PATTERSON UTI ENERGY INC
Form 10-K
February 13, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

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.)

10713 W. Sam Houston Pkwy N, Suite 800, Houston, Texas	77064
(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 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

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

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

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	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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $3.1 billion, calculated by reference to the closing price of $21.32 for the common stock on the Nasdaq Global Select Market on that date.

As of February 6, 2017, the registrant had outstanding 166,334,905 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 2017 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

SPECIAL NOTE 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 include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; rig counts; source and sufficiency of funds required for building new equipment, upgrading existing equipment and additional acquisitions (if opportunities arise); impact of inflation; demand for our services; competition; equipment availability; government regulation; debt service obligations; 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 "anticipate," "believe," "budgeted," "continue," "could," "estimate," "expect," "intend," "may," "plan," "predict," "potential," "project," "pursue," "should," "strat or the negative thereof 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.

On December 12, 2016, we entered into an Agreement and Plan of Merger (the "merger agreement") with Seventy Seven Energy Inc. ("SSE"), pursuant to which a subsidiary of ours will be merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly owned subsidiaries (the "SSE merger"). These forward-looking statements include, without limitation, our expectations with respect to:

- synergies, costs and other anticipated financial impacts of the SSE merger;
- future financial and operating results of the combined company;
- the combined company's plans, objectives, expectations and intentions with respect to future operations and services;
- approval of the SSE merger by stockholders;
- the satisfaction of the closing conditions to the SSE merger; and
- the timing of the completion of the SSE merger.

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. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These risks and uncertainties also include those set forth under "Risk Factors" contained in Item 1A of this Report and in 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, as well as, among others, risks and uncertainties relating to:

- the receipt of approval of both our and SSE's stockholders;
- the time required to complete the SSE merger;
- uncertainty as to whether the conditions to closing the SSE merger will be satisfied or whether the SSE merger will be completed;
- the diversion of management time on merger-related issues;
- the ultimate timing, outcome and results of integrating our operations with those of SSE;
- the effects of our business combination with SSE, including the combined company's future financial condition, results of operations, strategy and plans;
- potential adverse reactions or changes to business relationships resulting from the announcement or completion of the SSE merger;
- expected benefits from the SSE merger and our ability to realize those benefits;
- expectations regarding regulatory approval of the SSE merger;
- whether merger-related litigation will occur and, if so, the results of any litigation, settlements and investigations;

- potential triggering of change of control provisions in certain agreements to which SSE is a party;
- availability of capital and the ability to repay indebtedness when due;

1

- 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;
- loss of key customers;
- utilization, margins and planned capital expenditures;
- interest rate volatility;
- compliance with covenants under our debt agreements;
- excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction;
- equipment specialization and new technologies;
- operating hazards attendant to the oil and natural gas business;
- failure by customers to pay or satisfy their contractual obligations (particularly with respect to fixed-term contracts);
- difficulty in building and deploying new equipment;
- expansion and development trends of the oil and natural gas industry;
- weather;
- shortages, delays in delivery, and interruptions in supply, of equipment and materials;
- the ability to retain management and field personnel;
- the ability to effectively identify and enter new markets;
- the ability to realize backlog;
- strength and financial resources of competitors;
- environmental risks and ability to satisfy future environmental costs;
- global economic conditions;
- adverse oil and natural gas industry conditions;
- adverse credit and equity market conditions;
- operating costs;
- competition and demand for our services;
- liabilities from operations for which we or SSE, as applicable, do not have and receive full indemnification or insurance;
- governmental regulation;
- ability to obtain insurance coverage on commercially reasonable terms;
- financial flexibility;
- legal proceedings; and
- other financial, operational and legal risks and uncertainties detailed from time to time in either Patterson-UTI's or SSE's SEC filings.

We caution that the foregoing list of factors is not exclusive. Additional information concerning these and other risk factors is contained in this Report and may be contained in our future filings with the SEC. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to update publicly or revise any of these forward-looking statements, whether as a result of new information, future events or otherwise. In the event that we update any forward-looking statement, no inference should be made that we will make additional updates with respect to that statement, related matters or any other forward-looking statements. All subsequent written and oral forward-looking statements concerning us, SSE, the SSE merger or other matters and attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements above.

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 are a Houston, Texas-based oilfield services company that primarily owns and operates in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. We were formed in 1978 and reincorporated in 1993 as a Delaware corporation.

Our contract drilling business operates in the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. As of December 31, 2016, we had a drilling fleet that consisted of 202 marketed 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. We also have a substantial inventory of drill pipe and drilling rig components that support our 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, 2016, we had approximately 1.1 million hydraulic horsepower (approximately 1.0 million of which was hydraulic fracturing 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 manufacture and sell pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, we own and invest, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Recent Developments

Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2014, 2015 and 2016 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter

2014:				
Average oil price per Bbl (1)	$98.75	$103.35	$97.78	$73.16
Average rigs operating per day - U.S. (2)	193	201	209	210
2015:				
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96
Average rigs operating per day - U.S. (2)	165	122	105	88
2016:				
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15
Average rigs operating per day - U.S. (2)	71	55	60	66

(1) The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.
(2) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have recovered substantially from the lows experienced in the first quarter of 2016. During the fourth quarter of 2016, the Organization of Petroleum Exporting Countries ("OPEC") and certain non-OPEC countries, including Russia, announced an agreement to cut oil production. The announcement resulted in an increase in oil prices, which averaged $51.97 per barrel in December 2016. In response to improved prices, U.S. rig counts have been increasing, and we believe they will continue to increase throughout 2017 if prices for these commodities remain at or above current levels.

Our rig count in the United States declined significantly during the industry downturn that began in late 2014, but has steadily improved on a monthly basis since May 2016. For the fourth quarter, our average rig count improved to 66 rigs in the United States, up from the third quarter average of 60 rigs. Our rig count in the United States at December 31, 2016 of 74 rigs was 42% greater than the low of 52 rigs in April 2016; however, it was 65% less than the high of 214 rigs in October 2014. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 44 rigs operating under term contracts during the first quarter of 2017 and an average of 37 rigs operating under term contracts throughout 2017.

Activity levels in our pressure pumping business have also improved. Looking forward, we expect to see further increases in activity across the industry, especially in the Permian Basin. We have reactivated two frac spreads since mid-December 2016 at a cost of approximately $2 million per spread, including both operating and capital expenditures. Approximately 45% of the more than one million hydraulic fracturing horsepower in our fleet remains stacked. We expect the cost to reactivate our remaining idle frac spreads would be approximately $3 million per frac spread, including both operating and capital expenditures.

On December 12, 2016, we entered into an Agreement and Plan of Merger (the "merger agreement") with Seventy Seven Energy Inc. ("SSE"), pursuant to which a subsidiary of ours will be merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly owned subsidiaries (the "SSE merger"). Under the merger agreement, we will acquire all of the issued and outstanding shares of common stock of SSE in exchange for approximately 49.6 million shares of our common stock, subject to certain downward adjustments set forth in the merger agreement. SSE provides contract drilling, pressure pumping and oilfield rental services in many of the most active oil and natural gas plays onshore in the United States. SSE owns a fleet of 40 AC drilling rigs, approximately 93% of which are pad capable, including 28 fit-for-purpose PeakeRigs™. The remainder of SSE's rig fleet includes 51 SCR rigs. Additionally, SSE owns approximately 500,000 horsepower of modern, efficient fracturing equipment located in the Anadarko Basin and Eagle Ford Shale. The SSE oilfield rentals business has a modern, well-maintained fleet of premium rental tools, and provides specialized services for land-based oil and natural gas drilling, completion and workover activities.

The completion of the SSE merger is subject to satisfaction or waiver of certain closing conditions, including, but not limited to, approval by our and SSE's respective stockholders and other closing conditions set forth in the merger agreement. Subject to closing conditions, the SSE merger is expected to be completed late in the first quarter or early in the second quarter of 2017.

Industry Segments

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

- contract drilling services, and
- pressure pumping services.

Both of these industry segments had operating losses in 2016 and 2015. In 2014, both of these industry segments had operating profits.

We changed our reporting segment presentation in 2016, as we no longer consider our oil and natural gas exploration and production activities to be significant to an understanding of our results. We now present the oil and natural gas exploration and production activities, drilling technology and international activities as "Other" and "Corporate" reflects only corporate activities. This change in segment presentation was applied retrospectively to all periods presented herein.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 15 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, independent and other oil and natural gas operators. As of December 31, 2016, we had 202 marketed land-based drilling rigs based in the following regions:

- 42 in west Texas and southeastern New Mexico,

- 16 in north central and east Texas and northern Louisiana,
- 35 in the Rocky Mountain region (Colorado, Wyoming and North Dakota),
- 35 in south Texas,
- 24 in western Oklahoma,
- 43 in the Appalachian region (Pennsylvania, Ohio and West Virginia), and
- 7 in western Canada.

Our marketed drilling rigs have rated maximum depth capabilities ranging from approximately 13,000 feet to 25,000 feet. All of these drilling rigs are electric rigs. An electric rig converts the power from its diesel engines 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 upgrades or replacement parts for marketed rigs.

Drilling rigs are typically equipped with engines, drawworks, top drives, 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. We have spent approximately $1.4 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 2016, 2015 and 2014, we spent approximately $73 million, $527 million and $772 million, respectively, on these capital expenditures.

Depth and complexity of the well, drill site conditions and the number of wells to be drilled on a pad 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 2016, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 14 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, applicable law 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 provides the program for 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 2016, 2015 and 2014 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,		
	2016	2015	2014
Average rigs operating per day - U.S.(1)	63	120	203
Average rigs operating per day - Canada(1)	2	4	8
Number of rigs operated during the year	100	223	231
Number of wells drilled during the year	1,470	2,448	3,740
Number of operating days	23,596	45,142	77,000

(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 a 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® rigs are electric rigs with advanced electronic drilling systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other automated pipe handling equipment. APEX® rigs that are pad capable 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. As of December 31, 2016, our marketed land-based drilling fleet was comprised of the following:

	Number of Rigs			
Classification	United States	Canada	Total	Percent Pad Capable
APEX® 1500 HP rigs	126	1	127	70 %
APEX® 1000 HP rigs	26	—	26	88 %
APEX® 1400 HP rigs	5	—	5	100 %
APEX® 2000 HP rigs	3	—	3	100 %
Other electric rigs	35	6	41	20 %
Total	195	7	202	63 %
Average horsepower	1,428	1,171	1,419	

The U.S. land rig industry has recently begun referring to certain high specification rigs as "super-spec" rigs. We consider a super-spec rig to be a 1,500 horsepower, AC powered rig that has a 750,000 pound hookload, has a 7,500 psi circulating system and is pad capable. We currently estimate there are approximately 375 super-spec rigs in the United States, which includes 65 of our APEX® 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, applicable law 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 1.1 million hydraulic horsepower (approximately 1.0 million of which was hydraulic fracturing horsepower) as of December 31, 2016. Pressure pumping equipment at December 31, 2016 included:

	Hydraulic Fracturing Equipment	Other Pumping Equipment	Total
Southwest Region:			
Number of units	284	30	314
Approximate hydraulic horsepower	662,000	30,890	692,890
Northeast Region:			
Number of units	169	94	263
Approximate hydraulic horsepower	353,800	55,400	409,200
Combined:			
Number of units	453	124	577
Approximate hydraulic horsepower	1,015,800	86,290	1,102,090

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 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.

Customers

Our customer base includes major, independent and other oil and natural gas operators. With respect to our consolidated operating revenues in 2016, we received approximately 51% from our ten largest customers and approximately 33% from our five largest customers. During 2016, one customer accounted for approximately $124 million, or approximately 14%, of our consolidated operating revenues. These revenues were earned in both our contract drilling and pressure pumping businesses. 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.

Competition

The contract drilling and pressure pumping businesses are highly competitive. Historically, available equipment used in these businesses has frequently exceeded demand, particularly in an industry downturn, such as the current market environment. 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 limitation, 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 operations.

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. For example, in December 2016, the U.S. Environmental Protection Agency (“EPA”) and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking by March 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. If changes are made to the classification of exploration and production wastes under 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, each 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, 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, including on groundwater quality and seismic activity, 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 or Other Aspects of the Oil and Gas Industry 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 U.S. 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, 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 drilling rigs, pressure pumping equipment 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, a substantial portion of our drilling rigs and pressure pumping equipment and certain other assets, such insurance does not cover the full replacement cost of such drilling rigs, pressure pumping equipment 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 insurance coverage, a $1.0 million per occurrence deductible on our equipment insurance coverage, a $2.0 million per occurrence deductible on our general liability coverage and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and cyber risks, and we 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 that is not fully covered by insurance or an enforceable and 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 3,600 full-time employees as of February 7, 2017. 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. When 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, and expectations about future prices, are affected by factors such as:

- market supply and demand,
- the desire and ability of OPEC to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries,
- domestic and international military, political, economic and weather conditions,
- 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. The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil prices averaged $49.15 during the fourth quarter of 2016. As a result of the lower level of oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. Currently, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our fracturing horsepower is stacked.

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. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers' expectations of future oil and natural gas prices. A continued decline in demand for oil and natural gas, prolonged low oil or natural gas prices or expectations of further decreases in oil and natural gas prices, would likely result in further reduced capital expenditures by our customers and decreased demand for our services, which could have a material adverse effect on 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 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, or an inability to obtain, financing by us, our customers and our suppliers and result in reduced demand for our services. Furthermore, these factors may result in certain of our customers experiencing an inability or unwillingness 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.

Excess Equipment and a Highly Competitive Oil Service Industry May Adversely Affect Our Utilization and Profit Margins and the Carrying Value of our Assets.

The North American land drilling and pressure pumping businesses are highly competitive, and at times available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. A low commodity price environment can result in substantially more drilling rigs and pressure pumping equipment being available than are needed to meet demand. In addition, in recent years there has been a substantial increase in the construction of new technology drilling rigs and new pressure pumping equipment. Low commodity prices and construction of new equipment can result in excess capacity and substantial competition for a declining number of drilling and pressure pumping contracts. Even in an environment of high oil and natural gas prices and increased drilling activity, reactivation and improvement of existing drilling rigs and pressure pumping equipment, construction of new technology drilling rigs and new pressure pumping equipment, and movement of drilling rigs and pressure pumping equipment from region to region in response to market conditions or otherwise can lead to an excess supply of equipment. In addition, we may be unable to replace fixed-term contracts that were terminated early, extend expiring contracts or obtain new contracts in the spot market, and the rates and other material terms under any new or extended contracts may be on substantially less favorable rates and terms. Accordingly, high competition and excess equipment can cause drilling and pressure pumping contractors to have difficulty maintaining utilization and profit margins and, at times, result in operating losses. We cannot predict the future level of competition or excess equipment in the oil and natural gas contract drilling or pressure pumping businesses or the level of demand for our contract drilling or pressure pumping services.

The excess supply of operable land drilling rigs, increasing rig specialization and excess pressure pumping equipment, which has been exacerbated by the decline in oil and natural gas prices could affect the fair market value or our drilling and pressure pumping equipment, which in turn could result in additional impairments of our assets. A prolonged period of lower oil and natural gas prices could result in future impairment to our long-lived assets and goodwill.

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 customer 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. In addition, certain states, including Louisiana, New Mexico, Texas and Wyoming, have enacted statutes generally referred to as "oilfield anti-indemnity acts" expressly prohibiting certain indemnity agreements contained in or related to oilfield services agreements. Such oilfield anti-indemnity acts may restrict or void a party's indemnification of us.

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 drilling rigs, pressure pumping equipment 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, a substantial portion of our drilling rigs and pressure pumping equipment and certain other assets, such insurance does not cover the full replacement cost of such drilling rigs, pressure pumping equipment 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 insurance coverage, a $1.0 million per occurrence deductible on our equipment insurance coverage, a $2.0 million per occurrence deductible on our general liability coverage, and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and cyber risks, and we 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 that is not fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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

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 or renegotiate or otherwise 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 terminate or renegotiate 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 termination or renegotiation 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. As of December 31, 2016, 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 $417 million. Our contract drilling backlog may continue to decline as fixed-term drilling contract coverage over time may not be offset by new contracts, including as a result of the decline in the price of oil and natural gas, capital spending reductions by our customers or other factors.

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 drilling 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 continue to 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. We have also improved existing drilling rigs and pressure pumping equipment by adding equipment designed to enhance functionality and performance. Although we take measures to ensure that we use advanced oil and natural gas drilling and pressure pumping technology, changes in technology, improvements in competitors' equipment and changes relating to the wells to be drilled and completed could make our equipment less competitive.

If we are not successful keeping pace with technological advances in a timely and cost-effective manner, demand for our services may decline. If any technology that we need to successfully compete is not available to us or that we implement in the future does not work as we expect, 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.

Shortages, Delays in Delivery, and Interruptions in Supply, of Equipment and Materials Could Adversely Affect Our Operating Results.

During periods of increased demand for drilling and pressure pumping services, the industry has experienced shortages of equipment for upgrades, drill pipe, replacement parts and other equipment 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 and materials, including as a result of commitments of vendors to other customers or third parties or bankruptcies or consolidation.

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 operate, maintain, upgrade and construct 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.

Loss of Key Personnel 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, particularly after a prolonged industry downturn. During periods of high demand for our services, wage rates for operations personnel are also likely to increase, resulting in higher operating costs. During periods of lower demand for our services, we may experience reductions in force and voluntary departures of key personnel, which could adversely affect our business and make it more it difficult to meet customer demands when demand for our services improves. In addition, even if it is generally a period of lower demand for our services, if there is a high demand for our services in certain areas, it may be difficult to attract and retain qualified personnel to perform services in such areas. The loss of key employees, the failure to attract and retain qualified personnel and the increase in labor costs 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 2016, we received approximately 51% from our ten largest customers, 33% from our five largest customers and 14% from our largest customer. 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. While we have entered into the merger agreement with SSE, there is no assurance that the SSE merger will be completed. The SSE merger is subject to a number of conditions, certain of which are beyond our control and may prevent, delay or otherwise materially adversely affect completion of the SSE merger. In addition, 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, improved commodity prices may cause contract drillers to continue to build new, high technology rigs and providers of pressure pumping services to 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 we 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. See "-Risk Factors Relating to the Pending SSE Merger."

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 and a manufacturer and servicer of oilfield service 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. In June 2016, the EPA published a final rule that updates and expands the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In addition, the EPA has announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry. In November 2016, the Department of the Interior issued final rules relating to the venting, flaring and leaking of natural gas by oil and natural gas producers who operate on federal and Indian lands. The rules limit routine flaring of natural gas, require the payment of royalties on avoidable gas losses and require plans or programs relating to gas capture and leak detection and repair. These or other initiatives 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 or Other Aspects of the Oil and Gas Industry 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 conducted 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 hydraulic fracturing practices. We responded to the inquiry. The EPA released its final report in December 2016. It concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. Further, we conduct drilling and pressure pumping activities in numerous states. Some parties believe that there is a correlation between hydraulic fracturing and other oilfield related activities and the increased occurrence of seismic activity. When caused by human activity, such seismic activity is called induced seismicity. The extent of this correlation, if any, is the subject of studies of both state and federal agencies. In addition, a number of lawsuits have been filed against other industry participants alleging damages and regulatory violations in connection with such activity. These and other ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act ("SDWA") and other aspects of the oil and gas industry.

In addition, legislation has been proposed, but not enacted, 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 enacted, 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 SDWA 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. Further, in March 2015, the Bureau of Land Management ("BLM") issued a final rule to regulate hydraulic fracturing on Indian land. The rule requires companies to publicly disclose chemicals used in hydraulic fracturing operations to the BLM. However, in June 2016, the U.S. District Court of Wyoming struck down the rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government. In June 2016, the EPA published final pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works. 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, Louisiana, Montana, North Dakota, Texas 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.

In addition, in light of concerns about induced seismicity, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the Oklahoma Corporation Commission ("OCC") has implemented volume reduction plans, and at times required shut-ins, for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation. The OCC also recently released well completion seismicity guidelines for operators in the SCOOP and STACK plays that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity.

Finally, some jurisdictions have taken steps to enact hydraulic fracturing bans or moratoria. In June 2015, New York banned 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 approved a moratorium on hydraulic fracturing in November 2014, though it was later lifted in 2015. 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.

The Design, Manufacture, Sale and Servicing of Products, including Rig Components, May Subject Us to Liability for Personal Injury, Property Damage and Environmental Contamination Should Such Equipment Fail to Perform to Specifications.

We provide products, including rig components such as top drives, to customers involved in oil and gas exploration, development and production. Because of applications which use our products and services, a failure of such equipment, or a failure of our customer to maintain or operate the equipment properly, could cause damage to the equipment, damage to the property of customers and others, personal injury and environmental contamination, leading to claims against us.

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. However, in June 2014, the U.S. Supreme Court in UARG v. EPA limited application of this rule to sources that would otherwise need permits based on emission of conventional pollutants. In April 2015, the D.C. Circuit Court of Appeals narrowed the rule in accordance with the Supreme Court's decision. In October 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting requirements. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also, in November 2016, the EPA published a final rule adding monitoring methods for detecting leaks from oil and gas equipment and emission factors for leaking equipment to be used to calculate and report GHG emissions resulting from equipment leaks. In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years. 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. In addition, during periods of depressed market conditions, such as the one we are currently experiencing, we may be subject to an increased risk of our customers, vendors, current and former employees and others initiating legal proceedings against us. 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. Also, through our recent Warrior acquisition, we sell products, including rig components, for use in numerous oil and gas producing regions outside of North America. 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
- receive awards for work and 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 parts of the world where contract drilling and pressure pumping activities are conducted or where our consumers for the Warrior products are located 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 we 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 operations.

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 and, from time to time, our 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. 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. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the credit facility. As of December 31, 2016, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on our debt to capitalization ratio at September 30, 2016, the applicable margin on LIBOR loans was 2.75% and the applicable margin on base rate loans was 1.75% as of January 1, 2017. Based on our debt to capitalization ratio at December 31, 2016, 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, 2017. As of December 31, 2016, we had no amounts outstanding under our revolving credit facility.

We have in place a reimbursement agreement pursuant to which we are required to reimburse the issuing bank on demand for any amounts that it has disbursed under any of our letters of credit issued thereunder. We are obligated to pay the issuing bank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of December 31, 2016, no amounts had been disbursed under any letters of credit.

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.

Risk Factors Related to the Pending SSE Merger

Our expectations regarding our business may be impacted by the following risk factors related to the pending SSE merger:

The SSE Merger is Subject to Conditions, Including Certain Conditions That May Not Be Satisfied, or Completed on a Timely Basis, If At All.

The SSE merger is subject to a number of conditions, certain of which are beyond our control and may prevent, delay or otherwise materially adversely affect completion of the SSE merger. Notably, the completion of the SSE merger is conditioned on receiving the approval of both our and SSE's respective stockholders. At any time prior to the receipt of such approvals, each of our board of directors and the board of directors of SSE may change its recommendation with respect to the SSE merger, in each case in response to a superior proposal or an intervening event if the applicable board of directors determines in good faith, after consultation with its outside counsel, that, among other things, the failure to do so would be inconsistent with its fiduciary duties under applicable law and complies with certain other specified conditions. Consequently, we cannot predict whether and when these conditions will be satisfied. Any delay in completing the SSE merger could cause the combined company not to realize some or all of the benefits that we expect to achieve if the SSE merger is successfully completed within its expected time frame.

Current Patterson-UTI Stockholders Will Have a Reduced Ownership and Voting Interest in the Combined Company After the SSE Merger.

We will issue up to 49,559,000 shares of common stock to SSE stockholders in the SSE merger. As a result of these issuances, SSE stockholders are expected to hold up to approximately 23% of the combined company's outstanding common stock immediately following completion of the SSE merger.

Our stockholders currently have the right to vote for our directors and on other matters affecting our company. Each of our stockholders will remain a stockholder of our company with a percentage ownership of the combined company that will be smaller than the stockholder's percentage of our company prior to the SSE merger. As a result of these reduced ownership percentages, our stockholders will have less voting power in the combined company than they now have with respect to our company.

Uncertainties Associated With the SSE Merger May Cause a Loss of Key Employees, Which Could Adversely Affect the Future Business and Operations of the Combined Company.

We are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plan. Our success until the SSE merger and the combined company's success after the SSE merger will depend in part upon our ability to retain key employees. Current and prospective employees may experience uncertainty about their roles within the combined company following the SSE merger, which may have an adverse effect on our ability to attract or retain key personnel. Accordingly, no assurance can be given that the combined company will be able to attract or retain key employees to the same extent that we have previously been able to attract or retain our own employees.

Failure to Complete the SSE Merger Could Negatively Impact Our Future Business and Financial Results.

We cannot make any assurances that we will be able to satisfy all of the conditions to the SSE merger or succeed in any litigation brought in connection with the SSE merger. If the SSE merger is not completed, our financial results may be adversely affected and we will be subject to several risks, including but not limited to:

- being required to pay SSE a termination fee of either $40,000,000 or $100,000,000, in each case under certain circumstances provided in the merger agreement;
- payment of costs relating to the SSE merger, such as legal, accounting, financial advisor and printing fees, regardless of whether the SSE merger is completed;
- the focus of our management team on the SSE merger instead of the pursuit of other opportunities that could have been beneficial to us; and
- the potential occurrence of litigation related to any failure to complete the SSE merger.

In addition, if the SSE merger is not completed, we may experience negative reactions from the financial markets and from our customers and employees. If the SSE merger is not completed, we cannot assure our stockholders that these risks will not materialize and will not materially and adversely affect our business, financial results and stock price.

The Merger Agreement Contains Provisions That Limit Our Ability to Pursue Alternatives to the SSE Merger, Could Discourage a Potential Competing Acquirer of Us From Making a Favorable Alternative Transaction Proposal and, in Specified Circumstances, Could Require Us to Pay a Termination Fee to SSE.

The merger agreement contains "non-solicitation" provisions that, subject to limited exceptions, restrict our ability to, among other things, directly or indirectly, solicit, initiate, facilitate, knowingly encourage or induce or take any action that could be reasonably expected to lead to the making, submission or announcement of a proposal competing with the transactions contemplated by the merger agreement. In addition, while our board of directors has the ability, in certain circumstances, to change its recommendation of the transaction to our stockholders, we cannot terminate the merger agreement to accept an alternative proposal, and SSE generally has an opportunity to modify the terms of the SSE merger and the merger agreement in response to any alternative proposals that may be made before our board of directors may withdraw or modify its recommendation. Moreover, in certain circumstances, we may be required to pay up to $7,500,000 of SSE's expenses or we may be required to pay SSE a termination fee of either $40,000,000 or $100,000,000.

These provisions could discourage a potential third party that might have an interest in acquiring all or a significant portion of us from considering or proposing that acquisition, even if it were prepared to pay consideration with a higher per share cash or market value than the market value proposed to be received or realized in the SSE merger. In addition, these provisions might result in a potential third party acquirer proposing to pay a lower price to our stockholders than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. If the merger agreement is terminated and we determine to seek another business combination, we may not be able to negotiate a transaction with another party on terms comparable to, or better than, the terms of the SSE merger.

Completion of the SSE Merger May Trigger Change in Control or Other Provisions in Certain Agreements to Which SSE is a Party.

The completion of the SSE merger may trigger change in control or other provisions in certain agreements to which SSE is a party. If we and SSE are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we and SSE are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to SSE or the combined company.

We and SSE May be Unable to Obtain the Regulatory Clearances and Approvals Required to Complete the SSE Merger or, in Order to Do So, We May be Required to Comply With Material Restrictions or Conditions.

Under the HSR Act, neither we nor SSE may complete the SSE merger until required information and materials are furnished to the U.S. Department of Justice ("DOJ") and the U.S. Federal Trade Commission ("FTC"), and the applicable waiting period under the HSR Act terminates or expires. On January 3, 2017, we and SSE filed the requisite notification and report forms under the HSR Act with the DOJ and the FTC. On January 13, 2017, we and SSE were notified by the FTC that the early termination of the waiting period under the HSR Act had been granted.

The SSE merger may also be subject to the regulatory requirements of other municipal, state, federal, or foreign governmental agencies and authorities. Regulatory entities may impose certain requirements or obligations as conditions for their approval or in connection with their review.

The merger agreement may require us to accept conditions from these regulators that could adversely impact the combined company without us having the right to refuse to close the SSE merger on the basis of those regulatory conditions. We cannot provide any assurance that we will obtain the necessary clearances or approvals, or that any required conditions will not have a material adverse effect on the combined company following the SSE merger or result in the abandonment of the SSE merger.

Additionally, even after the above-described statutory waiting periods have expired, and even after completion of the SSE merger, governmental authorities could seek to challenge the SSE merger. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

The Pendency of the SSE Merger Could Adversely Affect Our Business and Operations.

In connection with the pending SSE merger, some of our customers or vendors may delay or defer decisions, which could negatively affect our revenues, earnings, cash flows and expenses, regardless of whether the SSE merger is completed. Similarly, our current and prospective employees may experience uncertainty about their future roles with the combined company following the SSE merger, which may materially adversely affect our ability to attract, retain and motivate key personnel during the pendency of the SSE merger and which may materially adversely divert attention from the daily activities of our existing employees.

In addition, due to operating covenants in the merger agreement, we may be unable, during the pendency of the SSE merger, to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing transactions and otherwise pursue other actions that are not in the ordinary course of business, even if such actions would prove beneficial to us. Further, the process of seeking to accomplish the SSE merger could also divert the focus of management from pursuing other opportunities that could be beneficial to us, without realizing any of the benefits which might have resulted had the SSE merger been completed.

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 10713 W. Sam Houston Parkway N., Suite 800, Houston, Texas, 77064. 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 and West Virginia.

Our manufacture, sale and service of pipe handling components are supported by offices and yard facilities located in western Canada and Texas. 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 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 4 of the Notes to Consolidated Financial Statements included in Item 8 of this Report.

Item 3. Legal Proceedings.

We are party to various legal proceedings arising in the normal course of its business. We do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our 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
2016		
First quarter	$18.75	$10.94
Second quarter	22.12	16.06
Third quarter	22.66	17.61
Fourth quarter	29.56	20.79
2015		
First quarter	$19.70	$13.30
Second quarter	23.11	18.30

Third quarter	18.80	12.97
Fourth quarter	17.45	12.82

(b) Holders

As of February 6, 2017, there were approximately 1,126 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2016 and 2015 as follows:

	Per Share	Total (in thousands)
2016		
Paid on March 24, 2016	$ 0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Paid on December 22, 2016	0.02	2,961
Total cash dividends	$ 0.16	$ 23,579
2015		
Paid on March 25, 2015	$ 0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$ 0.40	$ 58,775

On February 8, 2017, our Board of Directors approved a cash dividend on our common stock in the amount of $0.02 per share to be paid on March 22, 2017 to holders of record as of March 8, 2017. 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 debt agreements and other factors. The merger agreement prohibits us (unless consented to in advance by SSE, which consent may not be unreasonably withheld, delayed or conditioned) from paying dividends to holders of our common stock in excess of $0.02 per share per quarter until the earlier of the effective time of the SSE merger and the termination of the merger agreement in accordance with its terms.

(d) 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, 2016.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in thousands)(1)

October 2016	—	$ —	—	$ 186,653
November 2016	—	$ —	—	$ 186,653
December 2016 (2)	16,325	$ 26.89	—	$ 186,653
Total	16,325		—	$ 186,653

(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.
(2) We withheld 16,325 shares in December 2016 with respect to exercises of stock options by directors. These shares were acquired at fair market value pursuant to the terms of the 2014 Plan and not pursuant to the stock buyback program.

23

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2011 through December 31, 2016, 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. We changed our peer group in 2016 to align with the peer group used by the compensation committee of our board of directors. In addition, our former peer group has been impacted by acquisitions over recent years. Our new peer group consists of Atwood Oceanics Inc., Basic Energy Services, Inc., Diamond Offshore Drilling Inc., Ensco plc., Forum Energy Technologies, Inc., FMC Technologies, Inc. (n/k/a TechnipFMC plc), Helmerich & Payne, Inc., Nabors Industries, Ltd., Noble Corp., Oceaneering International, Oil States International Inc., Precision Drilling Corporation, Parker Drilling Company, Rowan Companies Inc., Superior Energy Services, Inc., Transocean Ltd., Unit Corp. and Weatherford International Ltd.

The graph assumes investment of $100 on December 31, 2011 and reinvestment of all dividends.

	Fiscal Year Ended December 31,					
	2011	2012	2013	2014	2015	2016
Company/Index	($)	($)	($)	($)	($)	($)
Patterson-UTI Energy, Inc.	100.00	94.38	129.45	86.18	80.24	144.44
Peer Group Index	100.00	102.72	121.96	81.22	53.18	58.98
S&P 500 Stock Index	100.00	116.00	153.57	174.60	177.01	198.18
Oilfield Service Index	100.00	103.17	133.69	102.23	78.32	93.19
S&P MidCap Index	100.00	117.88	157.37	174.74	168.98	204.03

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, 2016, 2015, 2014, 2013 and 2012, and for each of the five years in the period ended December 31, 2016, 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.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$543,663	$1,153,892	$1,838,830	$1,679,611	$1,821,713
Pressure pumping	354,070	712,454	1,293,265	979,166	841,771
Other	18,133	24,931	50,196	57,257	59,930
Total	915,866	1,891,277	3,182,291	2,716,034	2,723,414
Operating costs and expenses:					
Contract drilling	305,804	608,848	1,066,659	968,754	1,075,491
Pressure pumping	334,588	612,021	1,036,310	744,243	580,878
Other	8,384	11,500	13,102	12,909	11,303
Depreciation, depletion, amortization and impairment	668,434	864,759	718,730	597,469	526,614
Impairment of goodwill	—	124,561	—	—	—
Selling, general and administrative	69,205	74,913	80,145	73,852	64,473
Other operating (income) expense, net	(14,323)	1,647	(15,781)	(3,384)	(33,806)
Provision for bad debts	—	—	—	—	1,100
Total	1,372,092	2,298,249	2,899,165	2,393,843	2,226,053
Operating income (loss)	(456,226)	(406,972)	283,126	322,191	497,361
Other expense	(39,970)	(35,477)	(28,843)	(25,750)	(21,688)
Income (loss) before income taxes	(496,196)	(442,449)	254,283	296,441	475,673
Income tax expense (benefit)	(177,562)	(147,963)	91,619	108,432	176,196
Net income (loss)	$(318,634)	$(294,486)	$162,664	$188,009	$299,477
Net income (loss) per common share:					
Basic	$(2.18)	$(2.00)	$1.12	$1.29	$1.96
Diluted	$(2.18)	$(2.00)	$1.11	$1.28	$1.96
Cash dividends per common share	$0.16	$0.40	$0.40	$0.20	$0.20
Weighted average number of common shares outstanding:					
Basic	146,178	145,416	144,066	144,356	151,144
Diluted	146,178	145,416	145,376	145,303	151,699
Balance Sheet Data:					
Total assets	$3,804,606	$4,529,484	$5,390,912	$4,683,375	$4,552,507
Borrowings under line of credit	—	—	303,000	—	—
Other long-term debt	598,437	787,900	667,029	678,873	688,188
Stockholders’ equity	2,248,724	2,561,131	2,905,810	2,755,997	2,640,657

Working capital	18,506	178,887	340,816	454,498	340,220

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

Recent Developments — Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2014, 2015 and 2016 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2014:				
Average oil price per Bbl (1)	$98.75	$103.35	$97.78	$73.16
Average rigs operating per day - U.S. (2)	193	201	209	210
2015:				
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96
Average rigs operating per day - U.S. (2)	165	122	105	88
2016:				
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15
Average rigs operating per day - U.S. (2)	71	55	60	66

(1) The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.
(2) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have recovered substantially from the lows experienced in the first quarter of 2016. During the fourth quarter of 2016, OPEC and certain non-OPEC countries, including Russia, announced an agreement to cut oil production. The announcement resulted in an increase in oil prices, which averaged $51.97 per barrel in December 2016. In response to improved prices, U.S. rig counts have been increasing, and we believe they will continue to increase throughout 2017 if prices for these commodities remain at or above current levels.

Our rig count in the United States declined significantly during the industry downturn that began in late 2014, but has steadily improved on a monthly basis since May 2016. For the fourth quarter, our average rig count improved to 66 rigs in the United States, up from the third quarter average of 60 rigs. Our rig count in the United States at December 31, 2016 of 74 rigs was 42% greater than the low of 52 rigs in April 2016; however, it was 65% less than the high of 214 rigs in October 2014. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 44 rigs operating under term contracts during the first quarter of 2017 and an average of 37 rigs operating under term contracts throughout 2017.

Activity levels in our pressure pumping business have also improved. Looking forward, we expect to see further increases in activity across the industry, especially in the Permian Basin. We have reactivated two frac spreads since mid-December 2016 at a cost of approximately $2 million per spread, including both operating and capital expenditures. Approximately 45% of the more than one million hydraulic fracturing horsepower in our fleet remains stacked. We expect the cost to reactivate our remaining idle frac spreads would be approximately $3 million per frac spread, including both operating and capital expenditures.

On December 12, 2016, we entered into the merger agreement with SSE, pursuant to which a subsidiary of ours will be merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly owned subsidiaries. Under the merger agreement, we will acquire all of the issued and outstanding shares of common stock of SSE in exchange for approximately 49.6 million shares of our common stock, subject to certain downward adjustments set forth in the merger agreement. SSE provides contract drilling, pressure pumping and oilfield rental services in many of the most active oil and natural gas plays onshore in the United States. SSE owns a fleet of 40 AC drilling rigs, approximately 93% of which are pad capable, including 28 fit-for purpose PeakeRigs™. The remainder of

SSE's rig fleet includes 51 SCR rigs. Additionally, SSE owns approximately 500,000 horsepower of modern, efficient fracturing equipment located in the Anadarko Basin and Eagle Ford Shale. The SSE oilfield rentals business has a modern, well-maintained fleet of premium rental tools, and provides specialized services for land-based oil and natural gas drilling, completion and workover activities.

The completion of the SSE merger is subject to satisfaction or waiver of certain closing conditions, including, but not limited to, approval by our and SSE's respective stockholders and other closing conditions set forth in the merger agreement. Subject to closing conditions, the SSE merger is expected to be completed late in the first quarter or early in the second quarter of 2017.

Management Overview — We are a Houston, Texas-based oilfield services company that primarily owns and operates in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. Our contract drilling business operates in the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. Our pressure pumping business operates primarily in Texas and the Appalachian region. We also manufacture and sell pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, we own and invest, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

There continues to be uncertainty with respect to the global economic environment, and oil and natural gas prices have been depressed. During the fourth quarter of 2016, our average number of rigs operating in the United States was 66 compared to an average of 88 drilling rigs operating during the same period in 2015. During the fourth quarter of 2016, our average number of rigs operating in Canada was two compared to an average of three drilling rigs operating during the fourth 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, 2016, our rig fleet included 161 APEX® rigs. We expect to add two new APEX® rigs to our fleet during 2017.

In connection with the development of horizontal shale and other unconventional resource plays, we have added equipment to perform service intensive fracturing jobs. As of December 31, 2016, we had approximately 1.1 million hydraulic horsepower in our pressure pumping fleet (approximately 1.0 million of which was hydraulic fracturing horsepower). We have increased the horsepower of our pressure pumping fleet by more than eight-fold since the beginning of 2009, although we have not ordered or committed to purchase any new horsepower since October 2014 and there is currently no new horsepower on order. In recent years, the industry-wide addition of new pressure pumping equipment to the marketplace and lower oil and natural gas prices have 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 contract drilling backlog as of December 31, 2016 and 2015 was $417 million and $710 million, respectively. The decrease in backlog at December 31, 2016 from December 31, 2015, is primarily due to the revenue earned since December 31, 2015, including revenue from the receipt of early termination payments, and the expiration and termination of certain of our term contracts. Approximately 29% of the total December 31, 2016 backlog is reasonably expected to remain after 2017. 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 or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, our term drilling contracts are generally 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 that 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 Continue to Decline and 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, 2016, our operating revenues consisted of the following (dollars in thousands):

	2016	2015	2014

Contract drilling	$543,663	59 %	$1,153,892	61 %	$1,838,830	58 %
Pressure pumping	354,070	39 %	712,454	38 %	1,293,265	41 %
Other	18,133	2 %	24,931	1 %	50,196	1 %
	$915,866	100 %	$1,891,277	100 %	$3,182,291	100 %

Generally, the profitability of our business is most impacted by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2016, our average number of rigs operating was 63 in the United States and two in Canada compared to 120 in the United States and four in Canada in 2015, and 203 in the United States and eight in Canada in 2014. Our average rig revenue per operating day was $23,040 in 2016 compared to $25,560 in 2015 and $23,880 in 2014. We had a consolidated net loss of $319 million for 2016 compared to consolidated net loss of $294 million for 2015 and consolidated net income of $163 million for 2014. The financial results for 2015 include pretax non-cash charges totaling approximately $288 million. These charges include $125 million from the impairment of all goodwill associated with our pressure pumping business, $131 million from the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components, $22.0 from the write-down of pressure pumping equipment and closed facilities and $10.7 million related to the impairment of certain oil and natural gas properties. The financial results for 2014 include a pretax non-cash charge of $77.9 million related to the retirement of mechanical rigs and the write-off of excess spare components.

27

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 number of rigs operating have significantly declined from 2014. In December 2016, our average number of rigs operating was 71 in the United States. In January 2017, our average number of rigs operating increased to 76 in the United States.

We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues, weather 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.

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 higher specification 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 will be retired. In 2016, we retired 19 mechanical rigs but recorded no impairment charge as we had written down 15 of those rigs in 2015 that remained marketed. In 2015, we identified 24 mechanical rigs and 9 non-APEX® electric rigs that would no longer be marketed. Also, we had 15 additional mechanical rigs that were not operating. Although these 15 rigs remained marketed at that time, we had lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, we recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remained marketed but were not operating, and the write-down of excess spare rig components to their realizable values. In 2014, we identified 55 mechanical rigs that we determined would no longer be marketed, and 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 reduced size of our mechanical fleet.

We also periodically evaluate our pressure pumping assets, and in 2015, we recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2016 or 2014.

We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives ("triggering events"). 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. 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.

Based on recent commodity prices, our results of operations for the year ended December 31, 2016 and management's expectations of operating results in future periods, we concluded that no triggering events occurred during the year ended December 31, 2016 with respect to our contract drilling or pressure pumping segments. Our expectations of future operating results were based on the assumption that activity levels in both segments will begin to recover by early 2017 in response to improved future oil prices.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, we concluded a triggering event had occurred and deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. We performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and we determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

Due to the continued deterioration of crude oil prices in the fourth quarter of 2015, we deemed it necessary to once again assess the recoverability of long-lived assets groups for both contract drilling and pressure pumping. We performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and we determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 100%, respectively.

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts would be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon our historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices. While we believe these assumptions with respect to future pricing for oil and natural gas are reasonable, actual future prices may vary significantly from the ones that were assumed. The timeframe over which oil and natural gas prices will recover is highly uncertain. Potential events that could affect our assumptions regarding future prices and the timeframe for a recovery are affected by factors such as:

- market supply and demand,
- the desire and ability of OPEC to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries
- domestic and international military, political, economic and weather conditions,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production,
- the price and availability of alternative fuels,
- the cost of exploring for, developing, producing and delivering oil and natural gas, and
- regulations regarding the exploration, development, production and delivery of oil and natural gas.

All of these factors are beyond our control. If the current oil and natural gas commodity price environment were to last through 2017 and beyond, our actual cash flows would likely be less than the expected cash flows used in the aforementioned 2015 assessments and could result in impairment charges in the future, and any such impairment charges could be material.

We concluded that no triggering events occurred during the year ended December 31, 2014 with respect to our contract drilling or pressure pumping segments based on our results of the operations for the year ended December 31, 2014 and the prevailing commodity prices at that time.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. Goodwill is evaluated at least annually as of 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 our 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, and if so, the resulting goodwill impairment is determined using a two-step quantitative impairment test. From time to time, we may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step of the quantitative testing 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 quantitative testing 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 such shortfall.

In connection with our annual goodwill impairment assessment as of December 31, 2016, we determined based on an assessment of qualitative factors that it was more likely than not that the fair values of our contract drilling reporting unit was greater than its carrying amount and further testing was not necessary. In making this determination, we considered the demand experienced during 2016 for our contract drilling business. 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 this reporting unit, as well as its operating results for 2016 and forecasted operating results for 2017. Lastly, management considered our overall market capitalization at December 31, 2016 and the significant amount of calculated excess of the fair value of our reporting unit over its carrying value from our 2015 quantitative impairment assessment of goodwill.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of our revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for our contract drilling and pressure pumping services, we performed a quantitative Step 1 impairment assessment of our goodwill as of September 30, 2015. In completing the Step 1 assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of our contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for our services, and assumptions related to discount rates, long-term growth rates and control premiums.

Based on the results of the Step 1 goodwill impairment test as of September 30, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 15%, and we concluded that no impairment was indicated in our contract drilling reporting unit; however, impairment was indicated in our pressure pumping reporting unit. In the third quarter of 2015, we recognized an impairment charge of $125 million associated with the impairment of all of the goodwill in our pressure pumping reporting unit.

In connection with our annual goodwill impairment assessment as of December 31, 2015, we performed a quantitative Step 1 impairment assessment of the goodwill in our contract drilling reporting unit. In completing the Step 1 assessment, the fair value of the contract drilling reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of the reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of our contract drilling reporting unit, such as future oil and natural gas prices and projected demand for our services, and assumptions related to discount rates, long-term growth rates and control premiums. Based on the results of the quantitative Step 1 impairment assessment of our goodwill, as of December 31, 2015, the fair value of our contract drilling reporting unit exceeded its carrying value by approximately 16%, and we concluded that no impairment was indicated in our contract drilling reporting unit.

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 respective carrying amounts and no further testing was deemed necessary. In making this determination, we considered the continued demand experienced during 2014 for our 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 reporting units. Additionally, operating results for 2014 and forecasted operating results for 2015 were also taken into account. Lastly, management considered our overall market capitalization at December 31, 2014 and the large amount of calculated excess of the fair values of our reporting units over their respective carrying values from our 2013 quantitative impairment assessment.

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 reporting unit in future periods, and any 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 2016, 2015 and 2014 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 both proved and unproved oil and natural gas properties totaled approximately $2.8 million, $10.7 million and $20.9 million for the years ended December 31, 2016, 2015 and 2014, respectively, and such amounts are 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, 2016 included approximately $18.5 million in working capital and $500 million available under our revolving credit facility.

On January 24, 2017, we entered into an agreement with certain lenders under our revolving credit facility pursuant to which we exercised approximately $95.8 million of the $100 million commitment increase feature available thereunder in order to increase the aggregate commitments under our revolving credit facility to approximately

$595.8 million. The effectiveness of the aggregate commitment increase is subject to certain conditions, including the consummation of the SSE merger and the repayment and termination of the SSE credit facility, as well as other customary conditions.

On January 27, 2017, we completed an offering of 18.2 million shares of our common stock, and we intend to use the net proceeds from this offering of approximately $470 million to fund the repayment of SSE's outstanding net indebtedness upon closing of the SSE merger. If the SSE merger is not consummated, we intend to use the net proceeds of the offering for general corporate purposes, which may include repayment of outstanding indebtedness or investments in working capital.

We believe our current liquidity, together with cash expected to be generated from operations in 2017, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt and pay cash dividends for at least the next 12 months. If under current market conditions we desire to pursue opportunities for growth, in addition to the SSE merger, 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, 2016, we had working capital of $18.5 million, including cash and cash equivalents of $35.2 million, compared to working capital of $179 million, including cash and cash equivalents of $113 million, at December 31, 2015.

During 2016, our sources of cash flow included:

- $305 million from operating activities, and
- $21.9 million in proceeds from the disposal of property and equipment.

During 2016, we used $255 million to repay long-term debt, $23.6 million to pay dividends on our common stock, $3.6 million to acquire shares of our common stock, $3.4 million to pay debt issuance costs and $120 million:

- to build and acquire components to build new drilling rigs,
- to purchase new pressure pumping equipment,
- to make capital expenditures for the betterment and refurbishment of existing 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 non-operating working interest basis.

We paid cash dividends during the year ended December 31, 2016 as follows:

	Per Share	Total (in thousands)
Paid on March 24, 2016	$ 0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Paid on December 22, 2016	0.02	2,961
Total cash dividends	$ 0.16	$ 23,579

On February 8, 2017, our Board of Directors approved a cash dividend on our common stock in the amount of $0.02 per share to be paid on March 22, 2017 to holders of record as of March 8, 2017. 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 debt agreements and other factors. The merger agreement prohibits us (unless consented to in advance by SSE, which consent may not be unreasonably withheld, delayed or conditioned) from paying dividends to holders of our common stock in excess of $0.02 per share per quarter until the earlier of the effective time of the SSE merger and the termination of the merger agreement in accordance with its terms.

On September 6, 2013, our Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of our common stock in open market or privately negotiated transactions. As of December 31, 2016, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the 2013 stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

We acquired shares of stock from directors in 2016 and from employees during 2016, 2015 and 2014 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. 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 or the Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2016, 2015 and 2014 were as follows (dollars in thousands):

	2016 Shares	Cost	2015 Shares	Cost	2014 Shares	Cost
Treasury shares at beginning of period	43,207,240	$907,045	42,818,585	$899,035	42,268,057	$880,888
Purchases pursuant to 2013 stock buyback program	8,488	183	8,618	180	13,898	466
Acquisitions pursuant to long-term incentive plans	176,889	3,866	380,037	7,830	536,630	17,681
Treasury shares at end of period	43,392,617	$911,094	43,207,240	$907,045	42,818,585	$899,035

2012 Credit Agreement — On September 27, 2012, we entered into a Credit Agreement (“Base Credit Agreement”). The Base Credit Agreement (as amended, the “Credit Agreement”) is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, we entered into Amendment No. 2 to the Credit Agreement (“Amendment No. 2”), which amended the Base Credit Agreement. The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time, subject to a borrowing base calculated by reference to ours and certain of our subsidiaries’ eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No. 2. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time. Subject to customary conditions, we may request that the lenders’ aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $600 million. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving credit facility; however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019.

The term loan facility included in the Base Credit Agreement, which facility was terminated in connection with Amendment No. 2, provided for a loan of $100 million, which was drawn on December 24, 2012 and was payable in quarterly principal installments. As a condition precedent, Amendment No. 2 required that we repay the entire outstanding principal amount of this term loan.

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. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our availability under the credit facility. As of December 31, 2016, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on our debt to capitalization ratio at September 30, 2016, the applicable margin on LIBOR loans is 2.75% and the applicable margin on base rate loans is 1.75% as of January 1, 2017. Based on our debt to capitalization ratio at December 31, 2016, 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, 2017. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the daily 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 domestic subsidiaries unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and ours arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover our or 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 40%. 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 our 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, 2016.

Amendment No. 2 limits our ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of the total consolidated book value of our consolidated assets on a pro forma basis, we will not be able to make such investment. Amendment No. 2 also restricts our ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in Amendment No. 2) is at least 1.50 to 1.00. In addition, Amendment No. 2 requires that, if our consolidated cash balance, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, we can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, we must repay such unused proceeds on the fourth business day following such borrowings. Amendment No. 2 also decreased the permitted amount of certain secured indebtedness of us and our subsidiaries and decreased the permitted amount of certain unsecured indebtedness of our subsidiaries.

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 our insolvency and bankruptcy, such acceleration is automatic), and (iii) require us to cash collateralize any outstanding letters of credit.

As of December 31, 2016, we had no amounts outstanding under our revolving credit facility, with available borrowing capacity of $500 million.

On January 17, 2017, we entered into Amendment No. 3 to Credit Agreement (“Amendment No. 3”), which amended the Credit Agreement by restating the definition of Consolidated EBITDA to provide for the add-back of transaction expenses related to the SSE merger.

On January 24, 2017, we entered into an agreement with certain lenders under our revolving credit facility pursuant to which we exercised approximately $95.8 million of the $100 million commitment increase feature available thereunder in order to increase the aggregate commitments under our revolving credit facility to approximately $595.8 million. The effectiveness of the aggregate commitment increase is subject to certain conditions, including the consummation of the SSE merger and the repayment and termination of the SSE credit facility, as well as other customary conditions.

2015 Reimbursement Agreement — On March 16, 2015, we entered into a Reimbursement Agreement (the “Reimbursement Agreement”) with The Bank of Nova Scotia (“Scotiabank”), pursuant to which we may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of December 31, 2016, we had $38.2 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by us at the time of issuance at such rates and amounts as are in accordance with Scotiabank’s prevailing practice. We are obligated to pay to Scotiabank interest on all amounts not paid on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

We have also agreed that if obligations under the Credit Agreement are secured by liens on any of our subsidiaries' property, then our reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015 (the "Continuing Guaranty"), our payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by our subsidiaries that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, we entered into a Term Loan Agreement (the “2015 Term Loan Agreement”). The 2015 Term Loan Agreement was a senior unsecured single-advance term loan facility pursuant to which we made a term loan borrowing of $200 million on March 18, 2015 (the “Term Loan Borrowing”). The Term Loan Borrowing was payable in quarterly principal installments, together with accrued interest. Loans under the 2015 Term Loan Agreement bore interest, at our election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

As a condition precedent to Amendment No 2, we repaid the entire outstanding principal amount under the 2015 Term Loan Agreement and terminated the agreement on July 8, 2016.

Senior Notes — 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 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 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 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 domestic subsidiaries other than subsidiaries that are not required to be guarantors under the Credit Agreement.

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 our 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 fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2016. 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 we default 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.

Commitment Letter – On December 12, 2016 in connection with the execution of the merger agreement, we entered into a financing commitment letter (the “Commitment Letter”) with Canyon Capital Advisors LLC for a senior unsecured bridge facility in an aggregate principal amount not to exceed $150 million (the “Bridge Facility”), for the purposes of repaying or redeeming certain of SSE and its subsidiaries’ indebtedness and to pay related fees and expenses. Any undrawn commitments under the Bridge Facility will automatically terminate on the closing date of the SSE merger. The Bridge Facility will be subject to representations, warranties and covenants that, subject to certain agreed modifications, will be substantially similar to our revolving credit facility. The funding of the Bridge Facility is subject to our compliance with customary terms and conditions precedent as set forth in the Commitment Letter, including, among others: (i) the execution and delivery by us of definitive documentation consistent with the Commitment Letter and (ii) the SSE merger shall have been, or substantially simultaneously with the funding under the Bridge Facility shall be, consummated in accordance with the terms of the merger agreement. We do not currently expect to enter into the Bridge Facility.

Commitments and Contingencies — The merger agreement provides for an expense reimbursement in an amount not to exceed $7.5 million in respect of bona fide, out of pocket expenses actually incurred by SSE in connection with the merger agreement if the merger agreement is terminated if our stockholders fail to approve the issuance of our common stock in the SSE merger. The merger agreement also provides that we may be required to pay SSE a termination fee of $100 million in certain circumstances, including if our board of directors changes its recommendation as a result of a superior parent proposal (as defined in the merger agreement) or if the merger agreement is terminated in certain circumstances and we enter into certain types of alternative acquisition transactions within 12 months of termination. In certain other circumstances, we may be required to pay SSE a termination fee of $40 million. In no event will we be obligated to make more than one expense reimbursement payment or more than one termination fee payment to SSE.

The description of the expense reimbursement, termination payments and other provisions of the merger agreement does not purport to be complete and is qualified in its entirety by the full text of the merger agreement, which we filed with the SEC on December 13, 2016 as Exhibit 2.1 to our Current Report on Form 8-K.

As of December 31, 2016, we maintained letters of credit in the aggregate amount of $38.2 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, 2016, no amounts had been drawn under the letters of credit.

As of December 31, 2016, we had commitments to purchase approximately $68.4 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. As of December 31, 2016, the remaining obligation under these agreements was approximately $17.0 million, of which materials with a total purchase price of approximately $9.5 million were required to be purchased during 2017. 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.

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, 2016 (dollars in thousands):

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Series A Notes (1)	$300,000	$—	$—	$300,000	$—
Interest on Series A Notes (2)	59,640	14,910	29,820	14,910	—
Series B Notes (3)	300,000	—	—	—	300,000
Interest on Series B Notes (4)	72,912	12,810	25,620	25,620	8,862
Leases (5)	31,053	5,707	9,515	6,686	9,145
Equipment purchases (6)	68,423	68,423	—	—	—

Inventory purchases (7)	17,025	9,525	7,500	—	—
	$849,053	$111,375	$72,455	$347,216	$318,007

(1) Principal repayment of the Series A Notes is required at maturity on October 5, 2020.
(2) Interest to be paid on the Series A Notes using 4.97% coupon rate.
(3) Principal repayment of the Series B Notes is required at maturity on June 14, 2022.
(4) Interest to be paid on the Series B Notes using 4.27% coupon rate.
(5) See Note 12 of Notes to Consolidated Financial Statements.
(6) Represents commitments to purchase major equipment to be delivered in 2017 based on expected delivery dates.
(7) 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, 2016.

Results of Operations

Comparison of the years ended December 31, 2016 and 2015

The following tables summarize operations by business segment for the years ended December 31, 2016 and 2015:

Contract Drilling	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Revenues	$543,663	$1,153,892	(52.9)%
Direct operating costs	305,804	608,848	(49.8)%
Margin (1)	237,859	545,044	(56.4)%
Selling, general and administrative	5,743	5,580	2.9 %
Depreciation, amortization and impairment	467,974	618,434	(24.3)%
Operating loss	$(235,858)	$(78,970)	198.7 %
Operating days	23,596	45,142	(47.7)%
Average revenue per operating day	$23.04	$25.56	(9.9)%
Average direct operating costs per operating day	$12.96	$13.49	(3.9)%
Average margin per operating day (1)	$10.08	$12.07	(16.5)%
Average rigs operating	64.5	123.7	(47.9)%
Capital expenditures	$72,508	$527,054	(86.2)%

(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 decline in prices for oil and natural gas, together with the reactivation and construction of new land drilling rigs in the United States in recent years, have resulted in 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 2016 and 2015 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2016:					
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15	$43.15
Average natural gas price per Mcf (2)	$2.00	$2.14	$2.88	$3.04	$2.51
2015:					
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96	$48.69
Average natural gas price per Mcf (2)	$2.90	$2.75	$2.76	$2.12	$2.63

(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.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 primarily due to higher average dayrates and early termination revenues of approximately $69.4 million. Early termination revenues were approximately $24.6 million in 2016. Depreciation, amortization and impairment expense for 2015 included a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. There were no similar charges in 2016. Capital expenditures were significantly lower as no new rigs were added to the fleet in 2016 and drilling activity was lower, which required less maintenance capital.

Pressure Pumping	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Revenues	$354,070	$712,454	(50.3)%
Direct operating costs	334,588	612,021	(45.3)%
Margin (1)	19,482	100,433	(80.6)%
Selling, general and administrative	11,238	16,318	(31.1)%
Depreciation, amortization and impairment	184,872	214,552	(13.8)%
Impairment of goodwill	—	124,561	NA
Operating loss	$(176,628)	$(254,998)	(30.7)%
Fracturing jobs	352	610	(42.3)%
Other jobs	799	2,080	(61.6)%
Total jobs	1,151	2,690	(57.2)%
Average revenue per fracturing job	$982.56	$1,117.95	(12.1)%
Average revenue per other job	$10.28	$14.66	(29.9)%
Average revenue per total job	$307.62	$264.85	16.1 %
Average direct operating costs per total job	$290.69	$227.52	27.8 %
Average margin per total job (1)	$16.93	$37.34	(54.7)%
Margin as a percentage of revenues (1)	5.5 %	14.1 %	(61.0)%
Capital expenditures	$39,584	$197,577	(80.0)%

(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 total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased in 2016 as a result of declines in both activity and pricing. Average revenue per fracturing job and average revenue per other job decreased due to market-related pricing constraints. Average revenue per total job and average direct operating costs per total job increased as a result of a shift in the job mix toward fracturing jobs. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Lower selling, general and administrative expense in 2016 reflects lower personnel costs due to headcount reductions. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2016. In addition, all of the goodwill associated with our pressure pumping business was impaired during 2015.

Other Operations	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Revenues	$18,133	$24,931	(27.3)%
Direct operating costs	8,384	11,500	(27.1)%
Margin (1)	9,749	13,431	(27.4)%
Selling, general and administrative	3,026	1,399	116.3 %
Depreciation, depletion and impairment	10,114	26,301	(61.5)%
Operating loss	$(3,391)	$(14,269)	(76.2)%
Capital expenditures	$6,116	$16,625	(63.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, depletion and impairment and selling, general and administrative expenses.

Revenues from other operations decreased as a result of lower production and lower oil prices which resulted in lower revenues from our oil and natural gas working interests. Direct operating costs include a reduction in production taxes due to lower revenues. Selling, general and administrative expense increased from 2015 as the 2016 results include costs related to our drilling technology service business which was acquired in September 2016. Depreciation, depletion and impairment expense in 2016 includes approximately $2.8 million of oil and natural gas property impairments as compared to approximately $10.7 million of oil and natural gas property impairments in 2015.

Corporate	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	$49,198	$51,616	(4.7)%
Depreciation	$5,474	$5,472	0.0 %
Other operating (income) expense, net			
Net gain on asset disposals	$(14,771)	$(10,613)	39.2 %
Other, including legal settlements, net of insurance reimbursements	448	12,260	(96.3)%
Other operating (income) expense, net	$(14,323)	$1,647	NA
Interest income	$327	$964	(66.1)%
Interest expense	$40,366	$36,475	10.7 %
Other income	$69	$34	102.9 %
Capital expenditures	$1,591	$2,520	(36.9)%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating (income) expense, net includes net gains associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been excluded from the results of specific segments. Interest expense increased primarily due to lower capitalized interest, as we reduced our level of capital expenditures in 2016. In addition, we repaid the entire outstanding principal amount of our bank term loans. As a result, we wrote off $1.4 million of previously unamortized debt issuance costs in 2016 related to these bank term loans.

Comparison of the years ended December 31, 2015 and 2014

The following tables summarize operations by business segment for the years ended December 31, 2015 and 2014:

Contract Drilling	Year Ended December 31, 2015	2014	% Change
	(Dollars in thousands)		
Revenues	$1,153,892	$1,838,830	(37.2)%
Direct operating costs	608,848	1,066,659	(42.9)%
Margin (1)	545,044	772,171	(29.4)%
Selling, general and administrative	5,580	6,297	(11.4)%
Depreciation, amortization and impairment	618,434	524,023	18.0 %
Operating income (loss)	$(78,970)	$241,851	NA
Operating days	45,142	77,000	(41.4)%
Average revenue per operating day	$25.56	$23.88	7.0 %
Average direct operating costs per operating day	$13.49	$13.85	(2.6)%
Average margin per operating day (1)	$12.07	$10.03	20.3 %
Average rigs operating	$123.7	211.0	(41.4)%
Capital expenditures	$527,054	$771,593	(31.7)%

(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 contributed to an excess capacity of land drilling rigs compared to demand. Customer demand 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 2015 and 2014 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2015:					
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96	$48.69
Average natural gas price per Mcf (2)	$2.90	$2.75	$2.76	$2.12	$2.63
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.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 primarily due to higher average dayrates and early termination revenues of approximately $69.4 million. Depreciation, amortization and impairment expense for 2015 includes a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. Depreciation, amortization and impairment expense for 2014 includes a charge of $77.9 million related to the retirement of mechanical drilling rigs and the write-off of excess spare mechanical rig components. The increase in depreciation expense also reflects significant capital expenditures incurred in recent years to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional related equipment such as top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment.

	Year Ended December 31,		
Pressure Pumping	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$712,454	$1,293,265	(44.9)%
Direct operating costs	612,021	1,036,310	(40.9)%
Margin (1)	100,433	256,955	(60.9)%
Selling, general and administrative	16,318	20,279	(19.5)%
Depreciation, amortization and impairment	214,552	147,595	45.4%
Impairment of goodwill	124,561	—	NA
Operating income (loss)	$(254,998)	$89,081	NA
Fracturing jobs	610	1,224	(50.2)%
Other jobs	2,080	4,253	(51.1)%

Total jobs	2,690	5,477	(50.9)%
Average revenue per fracturing job	$1,117.95	$991.89	12.7 %
Average revenue per other job	$14.66	$18.62	(21.3)%
Average revenue per total job	$264.85	$236.13	12.2 %
Average direct operating costs per total job	$227.52	$189.21	20.2 %
Average margin per total job (1)	$37.34	$46.92	(20.4)%
Margin as a percentage of revenues (1)	14.1 %	19.9 %	(29.1)%
Capital expenditures and acquisitions	$197,577	$241,359	(18.1)%

(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 total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

40

Revenues and direct operating costs decreased primarily due to a decrease in the number of jobs, although the average size of the fracturing jobs increased. Average revenue per fracturing job and average direct operating costs per total job increased as a result of the increased size of the jobs in 2015 as compared to 2014. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2014. Depreciation expense also increased due to capital expenditures and acquisitions. All of the goodwill associated with our pressure pumping business was impaired during 2015.

Other	Year Ended December 31, 2015	2014	% Change
	(Dollars in thousands)		
Revenues	$24,931	$50,196	(50.3)%
Direct operating costs	11,500	13,102	(12.2)%
Margin (1)	13,431	37,094	(63.8)%
Selling, general and administrative	1,399	1,256	11.4 %
Depreciation, depletion and impairment	26,301	42,576	(38.2)%
Operating loss	$(14,269)	$(6,738)	111.8 %
Capital expenditures	$16,625	$36,683	(54.7)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, depletion and impairment and selling, general and administrative expenses.

Revenues from other operations decreased as a result of lower commodity prices which resulted in lower revenues from our oil and natural gas working interests. Direct operating costs include a reduction in production taxes due to lower revenues. Depreciation, depletion and impairment expense in 2015 includes approximately $10.7 million of oil and natural gas property impairments compared to approximately $20.9 million of oil and natural gas property impairments in 2014.

Corporate	Year Ended December 31, 2015	2014	% Change
	(Dollars in thousands)		
Selling, general and administrative	$51,616	$52,313	(1.3)%
Depreciation	$5,472	$4,536	20.6 %
Other operating (income) expense, net			
Net gain on asset disposals	$(10,613)	$(15,781)	(32.7)%
Legal settlements, net of insurance reimbursements	12,260	—	NA
Other operating (income) expense, net	$1,647	$(15,781)	NA
Interest income	$964	$979	(1.5)%
Interest expense	$36,475	$29,825	22.3 %
Other income	$34	$3	1,033.3%
Capital expenditures	$2,520	$2,706	(6.9)%

Gains on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Interest expense increased primarily due to borrowings under the 2015 Term Loan Agreement.

41

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by U.S. GAAP. We define Adjusted EBITDA as net income (loss) plus net interest expense, income tax expense (benefit) and depreciation, depletion, amortization and impairment expense (including impairment of goodwill). We present Adjusted EBITDA (a non-U.S. GAAP measure) because we believe it provides to both management and investors additional information with respect to both the performance of our fundamental business activities and our ability to meet our capital expenditures and working capital requirements. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measure of net income (loss). Set forth below is a reconciliation of Adjusted EBITDA to our net income (loss), the nearest performance measure under U.S. GAAP.

	Year Ended December 31,		
	2016	2015	2014
	(Dollars in thousands)		
Net income (loss)	$(318,634)	$(294,486)	$162,664
Income tax expense (benefit)	(177,562)	(147,963)	91,619
Net interest expense	40,039	35,511	28,846
Depreciation, depletion, amortization and impairment	668,434	864,759	718,730
Impairment of goodwill	—	124,561	—
Adjusted EBITDA	$212,277	$582,382	$1,001,859

Income Taxes

	Year Ended December 31,		
	2016	2015	2014
	(Dollars in thousands)		
Income (loss) before income taxes	$(496,196)	$(442,449)	$254,283
Income tax expense (benefit)	$(177,562)	$(147,963)	$91,619
Effective tax rate	35.8 %	33.4 %	36.0 %

The effective tax rate is a result of a federal rate of 35.0% adjusted as follows:

	2016	2015	2014
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	2.0	2.1	2.5
Permanent differences	(0.1)	(1.3)	(1.4)
Other differences, net	(1.1)	(2.4)	(0.1)
Effective tax rate	35.8%	33.4%	36.0%

The lower 2015 effective rate is primarily related to the impact of goodwill impairment charges in 2015 along with an adjustment to our deferred tax liability associated with the 2010 conversion of our Canadian operations to a controlled foreign corporation.

We record deferred federal income taxes based primarily on the temporary differences between the book and tax bases of our assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be settled. As a result of fully recognizing the benefit of our deferred income taxes, we incur deferred income tax expense as these benefits are utilized. We recognized a deferred tax benefit of approximately $152 million in 2016 and $100 million in 2015 and deferred tax expense of approximately $43.7 million in 2014.

On January 1, 2010, we converted our Canadian operations from a Canadian branch to a controlled foreign corporation for federal income tax purposes. This transaction triggered a $1.0 million increase in deferred tax liabilities, which is being amortized as an increase to deferred income tax expense over the weighted average remaining useful life of the Canadian assets. This amount was fully amortized as of December 31, 2016.

As a result of the above conversion, our Canadian assets are no longer directly subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, we have elected to permanently reinvest these unremitted earnings in Canada, and we intend to do so for the foreseeable future. As a result, no deferred United States federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $18.8 million as of December 31, 2016. The unrecognized deferred tax liability associated with these earnings was approximately $2.5 million, net of available foreign tax credits. This liability would be recognized if we received a dividend of the unremitted earnings.

Volatility of Oil and Natural Gas Prices and its Impact on Operations and Financial Condition

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 many factors beyond our control. Please see "Risk Factors – 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" in Item 1A of this Report. The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have recovered substantially from the lows experienced in the first quarter of 2016. During the fourth quarter of 2016, OPEC and certain non-OPEC countries, including Russia, announced an agreement to cut oil production. The announcement resulted in an increase in oil prices, which averaged $51.97 per barrel in December 2016. In response to improved prices, U.S. rig counts have been increasing, and we believe they will continue to increase throughout 2017 if prices for these commodities remain at or above current levels.

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. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers' expectations of future oil and natural gas prices. A continued decline in demand for oil and natural gas, prolonged low oil or natural gas prices or expectations of further decreases in oil and natural gas prices, would likely result in further reduced capital expenditures by our customers and decreased demand for our services, which could have a material adverse effect on 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 services.

Impact of Inflation

Inflation has not had a significant impact on our operations during the three years ended December 31, 2016. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. We expect to adopt this new revenue guidance utilizing the retrospective method of adoption in the first quarter of 2018, and because we are still evaluating the portion of our contract drilling revenues that will be subject to the new leasing guidance discussed below, we are unable to quantify the impact that the new revenue standard will have on our consolidated financial statements upon adoption.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. Since a portion of our contract drilling revenue will be subject to this new leasing guidance, we expect to adopt this updated leasing guidance at the same time we adopt the new revenue standard discussed above, utilizing the retrospective method of adoption. Upon adoption of these two new standards, we expect to have a lease component and a service component of revenue related to our drilling contracts. We are still evaluating the impact of this new guidance on our consolidated financial statements. This new leasing guidance will also impact us in situations where we are the lessee, and in certain circumstances we will need to record a right-of-use asset and lease liability on our consolidated financial statements. We have not quantified the impact of this guidance to such situations, although we expect the future minimum rental payments disclosed in Note 12 of our consolidated financial statements will provide some visibility into our estimated adoption impact.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

In March 2016, the FASB issued an accounting standards update to provide guidance for the accounting for share-based payment transactions, including the related income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. We believe this guidance will cause volatility in our effective tax rates and diluted earnings per share due to the tax effects related to share-based payments being recorded in the income statement. The volatility in future periods will depend on our stock price and the number of shares that vest in the case of restricted stock, or the number of shares that are exercised in the case of stock options.

In August 2016, the FASB issued an accounting standard to clarify the presentation of cash receipts and payments in specific situations on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We currently have exposure to interest rate market risk associated with any borrowings that we have under the Credit Agreement and the Reimbursement Agreement.

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. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the credit facility. As of December 31, 2016, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on our debt to capitalization ratio at September 30, 2016, the applicable margin on LIBOR loans was 2.75% and the applicable margin on base rate loans was 1.75% as of January 1, 2017. Based on our debt to capitalization ratio at December 31, 2016, 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, 2017. As of December 31, 2016, we had no amounts outstanding under our revolving credit facility.

Under the Reimbursement Agreement, we will reimburse the issuing bank on demand for any amounts that it has disbursed under any letters of credit. We are obligated to pay to the issuing bank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of December 31, 2016, no amounts had been disbursed under any letters of credit.

We conduct a portion of our business in Canadian dollars through our Canadian land-based drilling operations and our Warrior Rig Technologies Limited subsidiary. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars. This currency risk is not material to our results of operations or financial condition.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

Item 8. Financial Statements and Supplementary Data.

Financial Statements are filed as a part of this Report at the end of Part IV hereof beginning at page F-1, Index to Consolidated Financial Statements, and are incorporated herein by this reference.

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures:

Under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act, as of the end of the period covered by this Report. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2016, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and is accumulated and reported to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting:

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our CEO and CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016, based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management has concluded that our internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-2 of this Report and which is incorporated by reference into Item 8 of this Report.

Changes in Internal Control over Financial Reporting:

There have been no changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Certain information required by Part III is omitted from this Report because we expect to file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A of the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Report and certain information included therein is incorporated herein by reference.

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

We have adopted a Code of Business Conduct and Ethics for Senior Financial Executives, which covers, among others, our principal executive officer and principal financial and accounting officer. The text of this code is located on our website under "Governance." Our Internet address is www.patenergy.com. We intend to disclose any amendments to or waivers from this code on our website.

Item 11. Executive Compensation.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

PART IV

Item 15. Exhibits and Financial Statement Schedule.

(a)(1) Financial Statements

See Index to Consolidated Financial Statements on page F-1 of this Report.

(a)(2) Financial Statement Schedule

Schedule II — Valuation and qualifying accounts is filed herewith on page S-1.

All other financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(a)(3) Exhibits

The following exhibits are filed herewith or incorporated by reference herein. Our Commission file number is 0-22664.

2.1	Agreement and Plan of Merger by and among Patterson-UTI Energy, Inc., Pyramid Merger Sub, Inc. and Seventy Seven Energy Inc., dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 2.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
3.1	

	Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.2	Certificate of Amendment to the Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.3	Certificate of Elimination with respect to Series A Participating Preferred Stock (filed October 27, 2011 as Exhibit 3.1 to the Company's Current Report on Form 8-K and

	incorporated herein by reference).
3.4	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).
10.1	Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned to REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).
10.2	Patterson-UTI Energy, Inc. 2005

	Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 21, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.3	First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated

	herein by reference).*
10.4	Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.5	Third Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.6	Fourth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit

10.2 to the Company’s Current Report on Form 8-K and incorporated herein by reference).*

10.7 Fifth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q and incorporated herein by reference).*

10.8 Form of Share-Settled Performance Unit Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 and incorporated herein by

	reference).*
10.9	Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (filed April 21, 2014 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

47

10.10	Form of Executive Officer Share-Settled Performance Share Award Agreement (filed April 21, 2014 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.11	Form of Executive Officer Share-Settled Performance Share Award Agreement (filed May 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.12	Form of Executive Officer Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated

	herein by reference).*
10.13	Form of Executive Officer Restricted Stock Award Agreement (filed May 2, 2016 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.14	Form of Executive Officer Stock Option Agreement (filed April 21, 2014 as Exhibit 10.4 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.15	Form of Non-Employee Director Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.5 to the Company's Current Report on Form 8-K and incorporated herein by

	reference).*
10.16	Form of Non-Employee Director Stock Option Agreement (filed April 21, 2014 as Exhibit 10.6 to the Company's Current Report on Form 8-K and incorporated herein by reference).*
10.17	Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (filed on February 25, 2005 as Exhibit 10.23 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*
10.18	Employment Agreement, effective as of

	January 1, 2017, by and between Patterson-UTI Drilling Company LLC and James M. Holcomb (filed January 17, 2017 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference). *
10.19	Employment Agreement, effective as of August 1, 2016, by and between Patterson-UTI Energy, Inc. and William Andrew Hendricks, Jr. (filed August 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference). *
10.20	Employment Agreement, effective as of August 1, 2016, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler.*+
10.21	Form of Indemnification

	Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon and Tiffany J. Thom (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*
10.22	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company's Annual Report

	on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.23	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.24	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit

	10.7 to the Company’s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.25	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company’s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.26	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1,

	2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.27	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.28	Credit Agreement dated September 27, 2012, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank,

N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed September 28, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.29	Amendment No. 1 to Credit Agreement dated as of January 9, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed January 12, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.30	Amendment No. 2 to Credit Agreement dated as of July 8, 2016, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed July 12, 2016 as Exhibit 10.1 to the Company's Current Report on

	Form 8-K and incorporated herein by reference).
10.31	Amendment No. 3 to Credit Agreement dated as of January 17, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto.+
10.32	Commitment Increase Agreement, dated as of January 24, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed January 24, 2017 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by

reference).

10.33	Note Purchase Agreement dated October 5, 2010 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed October 6, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.34	Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010) (filed October 28, 2015 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

10.35	Note Purchase Agreement dated June 14, 2012 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed June 18, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.36	Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012) (filed October 28, 2015 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

10.37	Reimbursement Agreement, dated as March 16, 2015, by and between Patterson-UTI Energy, Inc. and The Bank of Nova Scotia (filed March 16, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.38	Continuing Guaranty, dated as of March 16, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 16, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.39	Term Loan Agreement, dated as March 18, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A.,

	as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents (filed March 18, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.40	Continuing Guaranty, dated as of March 18, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 18, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.41	

	Commitment Letter, dated December 12, 2016, between Patterson-UTI Energy, Inc. and Canyon Capital Advisors LLC (filed December 13, 2016 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.42	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Axar Capital Management, LLC, dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.43	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Blue Mountain Capital Management, LLC, dated as of

	December 12, 2016 (filed December 13, 2016 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.44	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Mudrick Capital Management, L.P., dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 10.4 to the Company's Current Report on Form 8-K and incorporated herein by reference).

21.1	Subsidiaries of the Registrant.+
23.1	Consent of Independent Registered Public Accounting Firm.+
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.+
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.+
32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.+
101	The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii)

the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, and (vi) Notes to Consolidated Financial Statements.+

* Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.
+Filed herewith.

Item 16. Form 10-K Summary

None.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Patterson-UTI Energy, Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Patterson-UTI Energy, Inc. and its subsidiaries (the "Company") at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 13, 2017

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2016	2015
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$35,152	$113,346
Accounts receivable, net of allowance for doubtful accounts of $3,191 and $3,545 at December 31, 2016 and 2015, respectively	148,091	219,672
Federal and state income taxes receivable	2,126	33,454
Inventory	20,191	14,716
Deferred tax assets, net	36,439	65,121
Other	41,322	40,227
Total current assets	283,321	486,536
Property and equipment, net	3,408,963	3,920,708
Goodwill and intangible assets	88,966	92,609
Deposits on equipment purchases	16,050	22,367
Other	7,306	7,264
Total assets	$3,804,606	$4,529,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$125,667	$82,771
Accrued expenses	139,148	161,611
Current portion of long-term debt, net of debt issuance cost of $483 at December 31, 2015	—	63,267
Total current liabilities	264,815	307,649
Long-term debt, net of debt issuance cost of $1,563 and $3,350 at December 31, 2016 and 2015, respectively	598,437	787,900
Deferred tax liabilities, net	682,976	863,833
Other	9,654	8,971
Total liabilities	1,555,882	1,968,353
Commitments and contingencies (see Note 9)		
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 191,525,872 and 190,374,801 issued and 148,133,255 and 147,167,561 outstanding at December 31, 2016 and 2015, respectively	1,915	1,904
Additional paid-in capital	1,042,696	1,011,811
Retained earnings	2,116,341	2,458,554

Accumulated other comprehensive loss	(1,134)	(4,093)
Treasury stock, at cost, 43,392,617 shares and 43,207,240 shares at December 31, 2016 and 2015, respectively	(911,094)	(907,045)
Total stockholders' equity	2,248,724	2,561,131
Total liabilities and stockholders' equity	$3,804,606	$4,529,484

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$543,663	$1,153,892	$1,838,830
Pressure pumping	354,070	712,454	1,293,265
Other	18,133	24,931	50,196
Total operating revenues	915,866	1,891,277	3,182,291
Operating costs and expenses:			
Contract drilling	305,804	608,848	1,066,659
Pressure pumping	334,588	612,021	1,036,310
Other	8,384	11,500	13,102
Depreciation, depletion, amortization and impairment	668,434	864,759	718,730
Impairment of goodwill	—	124,561	—
Selling, general and administrative	69,205	74,913	80,145
Other operating (income) expense, net	(14,323)	1,647	(15,781)
Total operating costs and expenses	1,372,092	2,298,249	2,899,165
Operating income (loss)	(456,226)	(406,972)	283,126
Other income (expense):			
Interest income	327	964	979
Interest expense, net of amount capitalized	(40,366)	(36,475)	(29,825)
Other	69	34	3
Total other expense	(39,970)	(35,477)	(28,843)
Income (loss) before income taxes	(496,196)	(442,449)	254,283
Income tax expense (benefit)	(177,562)	(147,963)	91,619
Net income (loss)	$(318,634)	$(294,486)	$162,664
Net income (loss) per common share:			
Basic	$(2.18)	$(2.00)	$1.12
Diluted	$(2.18)	$(2.00)	$1.11
Weighted average number of common shares outstanding:			
Basic	146,178	145,416	144,066
Diluted	146,178	145,416	145,376
Cash dividends per common share	$0.16	$0.40	$0.40

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Net income (loss)	$(318,634)	$(294,486)	$162,664
Other comprehensive loss, net of taxes of $0 for 2016, $0 for 2015 and $0 for 2014:			
Foreign currency translation adjustment	2,959	(10,556)	(7,613)
Total comprehensive income (loss)	$(315,675)	$(305,042)	$155,051

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock Number of Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands)						
Balance, December 31, 2013	186,487	$ 1,865	$ 913,505	$ 2,707,439	$ 14,076	$ (880,888)	$ 2,755,997
Net income	—	—	—	162,664	—	—	162,664
Foreign currency translation adjustment	—	—	—	—	(7,613)	—	(7,613)
Issuance of restricted stock	1,102	11	(11)	—	—	—	—
Vesting of restricted stock units	10	1	—	—	—	—	1
Forfeitures of restricted stock	(61)	(1)	1	—	—	—	—
Exercise of stock options	1,725	17	35,418	—	—	—	35,435
Stock-based compensation	—	—	27,032	—	—	—	27,032
Tax benefit related to stock-based compensation	—	—	8,729	—	—	—	8,729
Payment of cash dividends	—	—	—	(58,288)	—	—	(58,288)
Purchase of treasury stock	—	—	—	—	—	(18,147)	(18,147)
Balance, December 31, 2014	189,263	1,893	984,674	2,811,815	6,463	(899,035)	2,905,810
Net loss	—	—	—	(294,486)	—	—	(294,486)
Foreign currency translation adjustment	—	—	—	—	(10,556)	—	(10,556)
Issuance of restricted stock	1,180	12	(12)	—	—	—	—
Vesting of restricted stock units	14	—	—	—	—	—	—
Forfeitures of restricted stock	(82)	(1)	1	—	—	—	—
Stock-based compensation	—	—	28,510	—	—	—	28,510
Tax benefit related to stock-based compensation	—	—	(1,362)	—	—	—	(1,362)
Payment of cash dividends	—	—	—	(58,775)	—	—	(58,775)
Purchase of treasury stock	—	—	—	—	—	(8,010)	(8,010)

Balance, December 31, 2015	190,375	1,904	1,011,811	2,458,554	(4,093)	(907,045)	2,561,131
Net loss	—	—	—	(318,634)	—	—	(318,634)
Foreign currency translation adjustment	—	—	—	—	2,959	—	2,959
Shares issued for acquisition	354	3	6,730	—	—	—	6,733
Issuance of restricted stock	785	8	(8)	—	—	—	—
Vesting of restricted stock units	15	—	—	—	—	—	—
Forfeitures of restricted stock	(43)	—	—	—	—	—	—
Exercise of stock options	40		707	—	—	—	707
Stock-based compensation	—	—	28,324	—	—	—	28,324
Tax expense related to stock-based compensation	—	—	(4,868)	—	—	—	(4,868)
Payment of cash dividends	—	—	—	(23,579)	—	—	(23,579)
Purchase of treasury stock	—	—	—	—	—	(4,049)	(4,049)
Balance, December 31, 2016	191,526	$ 1,915	$ 1,042,696	$ 2,116,341	$ (1,134)	$ (911,094)	$ 2,248,724

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2016	2015	2014
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$(318,634)	$(294,486)	$162,664
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	668,434	864,759	718,730
Impairment of goodwill	—	124,561	—
Dry holes and abandonments	58	1,224	550
Deferred income tax expense (benefit)	(152,160)	(99,873)	43,673
Stock-based compensation expense	28,324	28,510	27,032
Net gain on asset disposals	(14,771)	(10,613)	(15,781)
Tax expense related to stock-based compensation	(4,868)	(1,362)	—
Amortization of debt issuance costs	2,270	1,245	653
Changes in operating assets and liabilities:			
Accounts receivable	72,327	440,884	(214,059)
Income taxes receivable/payable	30,379	49,895	(92,352)
Inventory and other assets	5,664	38,993	(6,390)
Accounts payable	12,024	(131,649)	86,621
Accrued expenses	(24,573)	(10,303)	12,838
Other liabilities	560	(2,348)	4,547
Net cash provided by operating activities	305,034	999,437	728,726
Cash flows from investing activities:			
Acquisitions	155	—	(176,301)
Purchases of property and equipment	(119,799)	(743,776)	(1,052,341)
Proceeds from disposal of assets	21,889	20,814	33,233
Net cash used in investing activities	(97,755)	(722,962)	(1,195,409)
Cash flows from financing activities:			
Purchases of treasury stock	(3,610)	(8,010)	(13,554)
Dividends paid	(23,579)	(58,775)	(58,288)
Tax benefit related to stock-based compensation	—	—	8,729
Proceeds from long-term debt	—	200,000	—
Repayment of long-term debt	(255,000)	(27,500)	(10,000)
Proceeds from borrowings under revolving credit facility	200,500	54,000	349,500
Repayment of borrowings under revolving credit facility	(200,500)	(357,000)	(46,500)
Debt issuance costs	(3,357)	(1,979)	—
Proceeds from exercise of stock options	268	—	30,842
Net cash provided by (used in) financing activities	(285,278)	(199,264)	260,729
Effect of foreign exchange rate changes on cash	(195)	(6,877)	(543)
Net increase (decrease) in cash and cash equivalents	(78,194)	70,334	(206,497)
Cash and cash equivalents at beginning of year	113,346	43,012	249,509
Cash and cash equivalents at end of year	$35,152	$113,346	$43,012
Supplemental disclosure of cash flow information:			

Net cash (paid) received during the year for:			
Interest, net of capitalized interest of $398 in 2016, $6,332 in 2015 and $6,883 in 2014	$(36,551)	$(33,452)	$(27,813)
Income taxes	52,716	97,333	(125,953)
Non-cash investing and financing activities:			
Net increase (decrease) in payables for purchases of property and equipment	$28,926	$(167,308)	$122,148
Issuance of common stock for business acquisition	6,733	—	—
Net decrease (increase) in deposits on equipment purchases	6,317	90,012	(59,819)

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., through its wholly-owned subsidiaries (collectively referred to herein as “Patterson-UTI” or the “Company”), provides onshore contract drilling services to oil and natural gas operators in the continental United States and western Canada. The Company provides pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. The Company also manufactures and sells pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, the Company owns and invests, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Basis of presentation — The consolidated financial statements include the accounts of Patterson-UTI and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any other entity which would require consolidation.

The U.S. dollar is the functional currency for all of the Company’s operations except for its Canadian subsidiaries, which use the Canadian dollar as their functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders’ equity.

During 2016, the Company determined that certain income and expense items should be classified as “other operating (income) expense, net” in the consolidated statements of operations. This caption now includes gains and losses on asset disposals and expenses related to certain legal settlements. Gains and losses on asset disposals were previously presented as a separate line in the consolidated statements of operations. Expenses related to certain legal settlements were previously included in operating costs of the respective operating segment or within selling, general and administrative expense. For comparative purposes, all such prior period amounts were reclassified to conform to the current presentation, including the Company’s previously disclosed $12.3 million legal settlement that was previously included within selling, general and administrative expense for the year ended December 31, 2015. Also during 2016, the Company adopted new guidance for the presentation of debt issuance costs as a direct deduction from the carrying amount of the related debt liability, and such guidance was applied retrospectively, resulting in the retroactive adjustment of debt issuance costs and the long-term debt as of December 31, 2015 (See Note 8). In addition, the Company changed its reporting segment presentation in 2016, as the Company no longer considers its oil and natural gas exploration and production activities to be significant to an understanding of the Company’s results. The Company now presents the oil and natural gas exploration and production activities, drilling technology and international activities as “Other” and “Corporate” reflects only corporate activities. This change in segment presentation was applied retrospectively to all periods presented herein (See Note 15).

A summary of the significant accounting policies follows:

Management estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure 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.

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 the Company drilled in 2016, 2015 and 2014 were drilled under daywork contracts.

Revenue is presented net of any sales tax charged to customers which the Company is required to remit to local or state governmental taxing authorities. Reimbursements for the purchase of supplies, equipment, personnel services, shipping and other services that are provided at the request of the Company's customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount. The allowance for doubtful accounts represents the Company's estimate of the amount of probable credit losses existing in the Company's accounts receivable. The Company reviews the adequacy of its allowance for doubtful accounts at least quarterly. Significant individual accounts receivable balances and balances which have been outstanding greater than 90 days are reviewed individually for collectability. Account balances, when determined to be uncollectable, are charged against the allowance.

Inventories — Inventories consist primarily of sand and other products to be used in conjunction with the Company's pressure pumping activities and materials used in its drilling technology business. Such inventories are stated at the lower of cost or market, with cost determined using the average cost method.

Other current assets — Other current assets includes reimbursement from the Company's workers compensation insurance carrier for claims in excess of the Company's deductible in the amount of $21.1 million and $25.1 million at December 31, 2016 and 2015, respectively.

Property and equipment — Property and equipment is carried at cost less accumulated depreciation. Depreciation is provided on the straight-line method over the estimated useful lives. The method of depreciation does not change whenever equipment becomes idle. The estimated useful lives, in years, are shown below:

	Useful Lives
Drilling rigs and other equipment	1.25-15
Buildings	15-20
Other	3-12

Long-lived assets, including property and equipment, are evaluated for impairment when certain triggering events or changes in circumstances indicate that the carrying values may not be recoverable over their estimated remaining useful life.

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. The Company reviews 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, the Company considers the well costs to be impaired and recognizes 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.

The Company reviews its 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 management's 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. The Company reviews unproved oil and natural gas properties quarterly to assess potential impairment. The Company's impairment assessment is made on a lease-by-lease basis and considers factors such as management's 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.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. The Company assesses impairment of its goodwill at least annually as of December 31, or on an interim basis if events or circumstances indicate that the fair value of goodwill may have decreased below its carrying value.

Maintenance and repairs — Maintenance and repairs are charged to expense when incurred. Renewals and betterments which extend the life or improve existing property and equipment are capitalized.

Disposals — Upon disposition of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statement of operations.

Net income (loss) per common share — The Company provides a dual presentation of its net income (loss) per common share in its consolidated statements of operations: Basic net income (loss) per common share (“Basic EPS”) and diluted net income (loss) per common share (“Diluted EPS”).

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate net income (loss) per share for the years ended December 31, 2016, 2015 and 2014, as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding because their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	2016	2015	2014
BASIC EPS:			
Net income (loss)	$(318,634)	$(294,486)	$162,664
Adjust for (income) loss attributed to holders of non-vested restricted stock	—	3,022	(1,663)
Income (loss) attributed to common stockholders	$(318,634)	$(291,464)	$161,001
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	146,178	145,416	144,066
Basic net income (loss) per common share	$(2.18)	$(2.00)	$1.12
DILUTED EPS:			
Income (loss) attributed to common stockholders	$(318,634)	$(291,464)	$161,001
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	146,178	145,416	144,066
Add dilutive effect of potential common shares	—	—	1,310
Weighted average number of diluted common shares outstanding	146,178	145,416	145,376
Diluted net income (loss) per common share	$(2.18)	$(2.00)	$1.11
Potentially dilutive securities excluded as anti-dilutive	9,057	7,781	1,088

Income taxes — The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized. The Company's policy is to account for interest and penalties with respect to income taxes as operating expenses.

Stock-based compensation — The Company recognizes the cost of share-based payments under the fair-value-based method. Under this method, compensation cost related to share-based payments is measured based on the estimated fair value of the awards at the date of grant, net of estimated forfeitures. This expense is recognized over the expected life of the awards (See Note 11).

Statement of cash flows — For purposes of reporting cash flows, cash and cash equivalents include cash on deposit and money market funds.

Recently Issued Accounting Standards — In May 2014, the Financial Accounting Standards Board ("FASB") issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The Company expects to adopt this new revenue guidance utilizing the retrospective method of adoption in the first quarter of 2018, and because the Company is still evaluating the portion of its contract drilling revenues that will be subject to the new leasing guidance discussed below, it is unable to quantify the impact that the new revenue standard will have on the Company's consolidated financial statements upon adoption.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. Since a portion of the Company's contract drilling revenue will be subject to this new leasing guidance, it expects to adopt this updated leasing guidance at the same time its adopts the new revenue standard discussed above, utilizing the retrospective method of adoption. Upon adoption of these two new standards, the Company expects to have a lease component and a service component of revenue related to its drilling contracts. The Company is still evaluating the impact of this new guidance on its consolidated financial statements. This new leasing guidance will also impact the Company in situations where it is the lessee, and in certain circumstances it will have a right-of-use asset and lease liability on its consolidated financial statements. The Company has not quantified the impact of this guidance to such situations, although it expects the future minimum rental payments disclosed in Note 12 will provide some visibility into the estimated adoption impact on the Company.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

In March 2016, the FASB issued an accounting standards update to provide guidance for the accounting for share-based payment transactions, including the related income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The Company believes this guidance will cause volatility in its effective tax rates and diluted earnings per share due to the tax effects related to share-based payments being recorded in the income statement. The volatility in future periods will depend on the Company's stock price and the number of shares that vest in the case of restricted stock, or the number of shares that are exercised in the case of stock options.

In August 2016, the FASB issued an accounting standard to clarify the presentation of cash receipts and payments in specific situations on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

2. Acquisitions

On December 12, 2016, the Company entered into an Agreement and Plan of Merger (the "merger agreement") with Seventy Seven Energy Inc. ("SSE") pursuant to which a subsidiary of the Company will be merged with and into SSE, with SSE continuing as the surviving entity and one of the Company's wholly owned subsidiaries (the "SSE merger"). Under the terms of the merger agreement, the Company will acquire all of the issued and outstanding shares of common stock of SSE, in exchange for approximately 49.6 million shares of common stock of the Company, subject to certain downward adjustments set forth in the merger agreement.

SSE provides contract drilling, pressure pumping and oilfield rental services in many of the most active oil and natural gas plays onshore in the United States. SSE owns a fleet of 40 AC drilling rigs, approximately 93% of which are pad capable, including 28 fit- for-purpose PeakeRigs™. The remainder of SSE's rig fleet includes 51 SCR rigs. Additionally, SSE owns approximately 500,000 horsepower of modern, efficient fracturing equipment located in the Anadarko Basin and Eagle Ford Shale. The SSE oilfield rentals business has a modern, well-maintained fleet of premium rental tools, and it provides specialized services for land-based oil and natural gas drilling, completion and workover activities. The completion of the merger is subject to satisfaction or waiver of certain closing conditions, including, but not limited to, approval by the Company's and SSE's respective stockholders and other closing conditions set forth in the merger agreement. Subject to closing conditions, the merger is expected to be completed late in the first quarter or early in the second quarter of 2017.

Additionally, during September 2016, the Company issued 353,804 shares of its common stock, valued at $6.7 million, in connection with the acquisition of Warrior Rig Ltd. and certain related entities ("Warrior"). Based in Calgary, Warrior manufactures and sells pipe handling components and related technology for drilling contractors in North America and other select markets. This acquisition was not significant to the Company's consolidated financial statements.

3. Inventory

Inventory consisted of the following at December 31, 2016 and 2015 (in thousands).

	2016	2015
Work-in-process	$1,803	$—
Raw materials and supplies	18,388	14,716
Inventory	$20,191	$14,716

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2016 and 2015 (in thousands):

	2016	2015
Equipment	$6,809,129	$6,963,148
Oil and natural gas properties	201,568	200,923
Buildings	97,029	96,470
Land	22,270	22,370
Total property and equipment	7,129,996	7,282,911
Less accumulated depreciation, depletion and impairment	(3,721,033)	(3,362,203)
Property and equipment, net	$3,408,963	$3,920,708

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment and intangible assets for 2016, 2015 and 2014 (in thousands):

	2016	2015	2014
Depreciation and impairment expense	$657,571	$845,543	$693,390
Amortization expense	3,643	3,643	3,643
Depletion expense	7,220	15,573	21,697
Total	$668,434	$864,759	$718,730

On a periodic basis, the Company evaluates its 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 higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to the Company’s other marketed rigs are transferred to other rigs or to the Company’s yards to be used as spare equipment. The remaining components of these rigs are retired. In 2016, the Company retired 19 mechanical rigs but recorded no impairment charge as it had written down 15 of those rigs in 2015 that remained marketed. In 2015, the Company identified 24 mechanical rigs and 9 non-APEX® electric rigs that would no longer be marketed. Also, the Company had 15 additional mechanical rigs that were not operating. Although these 15 rigs remained marketed at that time, the Company had lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, the Company recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remained marketed but were not operating, and the write-down of excess spare rig components to their realizable values. In 2014, the Company identified 55 mechanical rigs that it determined would no longer be marketed, and the Company 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 reduced size of the Company’s mechanical fleet.

The Company also periodically evaluates its pressure pumping assets, and in 2015, the Company recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2016 or 2014.

The Company reviews its long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that their carrying amounts of certain assets may not be recovered over their estimated remaining useful lives ("triggering events"). 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 Company estimates future cash flows over the life of the respective assets or asset groupings in its assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as the Company'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.

Based on recent commodity prices, the Company's results of operations for the year ended December 31, 2016 and management's expectations of operating results in future periods, the Company concluded that no triggering events occurred during the year ended December 31, 2016 with respect to its contract drilling or pressure pumping segments. Management's expectations of future operating results were based on the assumption that activity levels in both segments will begin to recover by early 2017 in response to improved future oil prices.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August 2015, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, management concluded a triggering event had occurred and deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

Due to the continued deterioration of crude oil prices in the fourth quarter of 2015, management deemed it necessary to once again assess the recoverability of long-lived assets groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 100%, respectively.

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts would be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon the Company's historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices. While management believed these assumptions with respect to future pricing for oil and natural gas were reasonable, actual future prices may vary significantly from the ones that were assumed. The timeframe over which oil and natural gas prices will recover is highly uncertain. Potential events that could affect the Company's assumptions regarding future prices and the timeframe for a recovery are affected by factors such as:

- market supply and demand,
- the desire and ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries
- domestic and international military, political, economic and weather conditions,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production,
- the price and availability of alternative fuels,
- the cost of exploring for, developing, producing and delivering oil and natural gas, and
- regulations regarding the exploration, development, production and delivery of oil and natural gas.

All of these factors are beyond the Company's control. If the current oil and natural gas commodity price environment were to continue through 2017 and beyond, the Company's actual cash flows would likely be less than the expected cash flows used in the aforementioned 2015 assessments and could result in impairment charges in the future, and any such impairment charges could be material.

The Company concluded that no triggering events occurred during the year ended December 31, 2014 with respect to its contract drilling or pressure pumping segments based on the Company's results of operations for the year ended December 31, 2014 and the prevailing commodity prices at that time.

With respect to the long-lived assets in the Company's oil and natural gas exploration and production segment, the Company assessed the recoverability of long-lived assets each quarter due to revisions in oil and natural gas reserve estimates and expectations about future commodity prices. The Company's analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable at various testing dates in 2016 and 2015. The

Company's estimates of expected future net cash flows from impaired properties are used in measuring the fair value of such properties. The Company recorded impairment charges of $2.8 million in 2016, $10.7 million in 2015 and $20.9 million in 2014 related to its oil and natural gas properties.

5. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2016 and 2015 and changes for the years then ended are as follows (in thousands):

	Contract Drilling	Pressure Pumping	Total
Balance December 31, 2014	$86,234	$124,561	$210,795
Changes to goodwill	—	(124,561)	(124,561)
Balance December 31, 2015	86,234	—	86,234
Changes to goodwill	—	—	—
Balance December 31, 2016	$86,234	$—	$86,234

There were no accumulated impairment losses related to goodwill in the contract drilling operating segment as of December 31, 2016 or 2015.

Goodwill is evaluated at least annually as of 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. The Company's reporting units for impairment testing have been determined to be its operating segments. The Company first determines 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, and if so, the resulting goodwill impairment is determined using a two-step quantitative impairment test. From time to time, the Company may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step of the quantitative testing 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 quantitative testing 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 such shortfall.

In connection with its annual goodwill impairment assessment as of December 31, 2016, the Company determined based on an assessment of qualitative factors that it was more likely than not that the fair values of the Company's contract drilling reporting unit was greater than its carrying amount and further testing was not necessary. In making this determination, the Company considered the demand experienced during 2016 for its contract drilling business. The Company also considered the current and expected levels of commodity prices for oil and natural gas, which influence its overall level of business activity in this reporting unit, as well as its operating results for 2016 and forecasted operating results for 2017. Lastly, management considered the Company's overall market capitalization at December 31, 2016 and the significant amount of calculated excess of the fair value of the Company's reporting unit over its carrying value from its 2015 quantitative impairment assessment of goodwill.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of the Company's revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for its contract drilling and pressure pumping services, the Company performed a quantitative Step 1 impairment assessment of its goodwill as of September 30, 2015. In completing the Step 1 assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods.

The estimate of fair value for each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

Based on the results of the Step 1 goodwill impairment test as of September 30, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 15%, and management concluded that no impairment was indicated in its contract drilling reporting unit; however, impairment was indicated in its pressure pumping reporting unit. In the third quarter of 2015, the Company recognized an impairment charge of $125 million associated with the impairment of all of the goodwill in its pressure pumping reporting unit.

In connection with its annual impairment asset at December 31, 2015, the Company performed a quantitative Step 1 impairment assessment of the goodwill in its contract drilling reporting unit. In completing the Step 1 assessment, the fair value of the contract drilling reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of the reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling reporting unit, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums. Based on the results of the quantitative Step 1 impairment assessment of its goodwill as of December 31, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 16%, and management concluded that no impairment was indicated in its contract drilling reporting unit.

In connection with its annual goodwill impairment assessment as of December 31, 2014, the Company determined based on an assessment of qualitative factors that it was more likely than not that the fair values of the Company's reporting units were greater than their respective carrying amounts and no further testing was deemed necessary. In making this determination, the Company considered the continued demand experienced during 2014 for its contract drilling and pressure pumping businesses. The Company also considered the current and expected levels of commodity prices for oil and natural gas, which influence its overall level of business activity in these reporting units. Additionally, operating results for 2014 and forecasted operating results for 2015 were also taken into account. Lastly, management considered the Company's overall market capitalization at December 31, 2014 and the large amount of calculated excess of the fair values of the Company's reporting units over their respective carrying values from its 2013 quantitative impairment assessment.

The Company has undertaken extensive efforts in the past several years to upgrade its fleet of equipment and believes that it is 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, the Company may be required to record an impairment of goodwill in its contract drilling reporting unit in future periods, and any such impairment could be material.

Intangible Assets — Intangible assets were recorded in the pressure pumping operating segment in connection with the fourth quarter 2010 acquisition of the assets of a pressure pumping business. As a result of the purchase price allocation, the Company recorded intangible assets related to a non-compete agreement and the customer relationships acquired. These intangible assets were recorded at fair value on the date of acquisition.

The value of the customer relationships was estimated using a multi-period excess earnings model to determine the present value of the projected cash flows associated with the customers in place at the time of the acquisition and taking into account a contributory asset charge. The resulting intangible asset is being amortized on a straight-line basis over seven years. Amortization expense of $3.6 million was recorded in each of the years ended December 31, 2016, 2015 and 2014, associated with customer relationships.

The Company concluded that no triggering events necessitating an impairment assessment of these customer relationships had occurred in 2016, 2015 or 2014. The assessment of the recoverability of the pressure pumping asset group included the customer relationship intangible asset, and no impairment was indicated.

The gross carrying amount and accumulated amortization of the customer relationships as of December 31, 2016 and 2015 are as follows (in thousands):

	2016 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	2015 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$25,500	$ (22,768)	$ 2,732	$25,500	$ (19,125)	$ 6,375

6. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2016 and 2015 (in thousands):

	2016	2015
Salaries, wages, payroll taxes and benefits	$21,138	$27,055
Workers' compensation liability	67,775	75,358
Property, sales, use and other taxes	6,766	9,061
Insurance, other than workers' compensation	9,566	12,817
Accrued interest payable	6,740	7,668
Other	27,163	29,652
	$139,148	$161,611

7. Asset Retirement Obligation

The Company records a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. This liability is included in the caption "other" in the liabilities section of the consolidated balance sheet.

The changes to the asset retirement obligations during 2016 and 2015 are as follows (in thousands):

	2016	2015
Balance at beginning of year	$5,692	$5,301
Liabilities incurred	164	340
Liabilities settled	(124)	(120)
Accretion expense	166	171
Revision in estimated costs of plugging oil and natural gas wells	42	—
Asset retirement obligation at end of year	$5,940	$5,692

8. Long-Term Debt

2012 Credit Agreement — On September 27, 2012, the Company entered into a Credit Agreement ("Base Credit Agreement") with Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto. The Base Credit Agreement (as amended, the "Credit Agreement") is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, the Company entered into Amendment No. 2 to the Credit Agreement (Amendment No. 2"), which amended the Base Credit Agreement. The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time, subject to a borrowing base calculated by reference to the Company's and certain of its subsidiaries' eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No 2. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time. Subject to customary conditions, the Company may request that the lenders' aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $600 million. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving credit facility, however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019.

The term loan facility included in the Base Credit Agreement, which facility was terminated in connection with Amendment No. 2, provided for a loan of $100 million, which was drawn on December 24, 2012 and was payable in quarterly principal installments. As a condition precedent, Amendment No. 2 required that the Company repay the entire outstanding principal amount of this term loan.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varies from 2.75% to 3.25% and the applicable margin on base rate loans varies from 1.75% to 2.25%, in each case determined based upon the Company's debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on the Company's excess availability under the credit facility. At December 31, 2016, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. Based on the Company's debt to capitalization ratio at September 30, 2016, the applicable margin on LIBOR rate loans is 2.75% and the applicable margin on base rate loans is 1.75% as of January 1, 2017. Based on the Company's debt to capitalization ratio at December 31, 2016, the applicable margin on LIBOR rate loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2017. A letter of credit fee is payable by the Company 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 domestic subsidiary of the Company unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover obligations of the Company and any subsidiary of the Company 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. The Company must not permit its debt to capitalization ratio to exceed 40%. 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. The Company also must not permit its 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. The Company was in compliance with these covenants at December 31, 2016.

Amendment No. 2 limits the Company's ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of the total consolidated book value of the assets of the Company and its subsidiaries on a pro forma basis, the Company will not be able to make such investment. Amendment No. 2 also restricts the Company's ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in Amendment No. 2) is at least 1.50 to 1.00. In addition, Amendment No. 2 requires that, if the consolidated cash balance of the Company and its subsidiaries, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, the Company can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, the Company must repay such unused proceeds on the fourth business day following such borrowings. Amendment No. 2 also decreased the permitted amount of certain secured indebtedness of the Company and its subsidiaries and decreased the permitted amount of certain unsecured indebtedness of the Company's subsidiaries.

The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants.

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 the Company to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic), and (iii) require the Company to cash collateralize any outstanding letters of credit.

As of December 31, 2016, the Company had no amounts outstanding under the revolving credit facility, with available borrowing capacity of $500 million.

On January 17, 2017, the Company entered into Amendment No. 3 to Credit Agreement ("Amendment No. 3"), which amended the Credit Agreement by restating the definition of Consolidated EBITDA to provide for the add-back of transaction expenses related to the SSE merger.

On January 24, 2017, the Company entered into an agreement with certain lenders under its revolving credit facility pursuant to which the Company exercised approximately $95.8 million of the $100 million commitment increase feature available thereunder in order to increase the aggregate commitments under its revolving credit facility to approximately $595.8 million. The effectiveness of the aggregate commitment increase is subject to certain conditions, including the consummation of the SSE merger and the repayment and termination of the SSE credit facility, as well as other customary conditions.

2015 Reimbursement Agreement — On March 16, 2015, the Company entered into a Reimbursement Agreement (the "Reimbursement Agreement") with The Bank of Nova Scotia ("Scotiabank"), pursuant to which the Company may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of December 31, 2016, the Company had $38.2 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, the Company will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by the Company at the time of issuance at such rates and amounts as are in accordance with Scotiabank's prevailing practice. The Company is obligated to pay to Scotiabank interest on all amounts not paid by the Company on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

The Company has also agreed that if obligations under the Credit Agreement are secured by liens on any of its or any of its subsidiaries' property, then the Company's reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015, the Company's payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by subsidiaries of the Company that from time to time guarantee payment under the Credit Agreement.

2015 Term Loan Agreement — On March 18, 2015, the Company entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement was a senior unsecured single-advance term loan facility pursuant to which the Company made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing was payable in quarterly principal installments, together with accrued interest. Loans under the 2015 Term Loan Agreement bore interest, at the Company's election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

As a condition precedent to Amendment No 2, the Company repaid the entire outstanding principal amount under the 2015 Term Loan Agreement and terminated the agreement on July 8, 2016.

Senior Notes – On October 5, 2010, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 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. The Company pays 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, the Company completed the issuance and sale of $300 million in aggregate principal amounts of its 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. The Company pays 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 senior unsecured obligations of the Company, which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of the existing domestic subsidiaries of the Company other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at the Company's 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. The Company must offer to prepay the notes upon the occurrence of any change of control. In addition, the Company 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. The Company must not permit its 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. The Company also must not permit its 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 fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2016.

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.

Commitment Letter – On December 12, 2016, in connection with execution of the merger agreement, the Company entered into a financing commitment letter (the "Commitment Letter") with Canyon Capital Advisors LLC for a senior unsecured bridge facility in an aggregate principal amount not to exceed $150 million (the "Bridge Facility"), for the purposes of repaying or redeeming certain of SSE and its subsidiaries' indebtedness and to pay related fees and expenses. Any undrawn commitments under the Bridge Facility will automatically terminate on the closing date of the SSE merger. The Bridge Facility will be subject to representations, warranties and covenants that, subject to certain agreed modifications, will be substantially similar to our revolving credit facility. The funding of the Bridge Facility is subject to our compliance with customary terms and conditions precedent as set forth in the Commitment Letter, including, among others: (i) the execution and delivery by us of definitive documentation consistent with the Commitment Letter and (ii) the SSE merger shall have been, or substantially simultaneously with the funding under the Bridge Facility shall be, consummated in accordance with the terms of the merger agreement. The Company does not currently expect to enter into the Bridge Facility.

The Company incurred approximately $10.8 million in debt issuance costs during 2010 in connection with the Series A Notes and a previous senior unsecured revolving credit facility. The Company incurred approximately $7.6 million in debt issuance costs during 2012 in connection with the Series B Notes and the Credit Agreement. The Company incurred approximately $2.0 million in debt issuance costs during 2015 in connection with the Reimbursement Agreement and the 2015 Term Loan Agreement. The Company incurred approximately $3.4 million in debt issuance costs during 2016 in connection with Amendment No. 2. These costs were deferred and are being recognized as interest expense over the term of the underlying debt.

In April and August 2015, the Financial Accounting Standards Board ("FASB") issued accounting standards updates to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs, except those related to line-of-credit arrangements, are presented in the balance sheet as a direct deduction from the carrying amount of the related debt. Debt issuance costs related to line-of-credit arrangements can continue to be classified as a deferred charge. Amortization of debt issuance costs continues to be reported as interest expense. This guidance became effective for the Company during the three months ended March 31, 2016. This guidance was applied retrospectively, and debt issuance costs and long-term debt as of December 31, 2015 were retroactively adjusted in the balance sheet. There was no impact on the Company's results of operations or cash flows as a result of the adoption of this guidance. Interest expense related to the amortization of debt issuance costs was approximately $4.1 million, $2.8 million and $2.2 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amortization of debt issuance costs for the year ended December 31, 2016 includes $1.4 million of costs related to the early termination of the 2012 and 2015 term loan agreements.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2016 (in thousands):

Year ending December 31,	
2017	$—
2018	—
2019	—
2020	300,000
2021	—
Thereafter	300,000
Total	$600,000

F-19

9. Commitments, Contingencies and Other Matters

Commitments – The merger agreement provides for an expense reimbursement in an amount not to exceed $7.5 million in respect of bona fide, out of pocket expenses actually incurred by SSE in connection with the merger agreement if the agreement is terminated if the Company's stockholders fail to approve the issuance of the Company's common stock in the SSE merger. The merger agreement also provides that the Company may be required to pay SSE a termination fee of $100 million in certain circumstances, including if the Company's board of directors changes its recommendation as a result of a superior parent proposal (as defined in the merger agreement) of if the merger agreement is terminated in certain circumstances and the Company enters into certain types of alternative acquisition transactions within 12 months of termination. In certain other circumstances, the Company may be required to pay SSE a termination fee of $40 million. In no event will the Company be obligated to make more than one expense reimbursement payment or more than one termination fee payment to SSE.

As of December 31, 2016, the Company maintained letters of credit in the aggregate amount of $38.2 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, 2016, no amounts had been drawn under the letters of credit.

As of December 31, 2016, the Company had commitments to purchase approximately $68.4 million of major equipment for its drilling and pressure pumping businesses.

The Company's pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. As of December 31, 2016, the remaining obligation under these agreements was approximately $17.0 million, of which materials with a total purchase price of approximately $9.5 million are required to be purchased during 2017. In the event that the required minimum quantities are not purchased during any contract year, the Company could be required to make a liquidated damages payment to the respective vendor for any shortfall.

Contingencies – The Company's 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 the Company to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

Any contractual right to indemnification that the Company may have for any such risk may be unenforceable or limited due to negligent or willful acts of commission or omission by the Company, its subcontractors and/or suppliers. In addition, certain states, including Louisiana, New Mexico, Texas and Wyoming, have enacted statutes generally referred to as "oilfield anti-indemnity acts" expressly prohibiting certain indemnity agreements contained in or related to oilfield service agreements. Such oilfield anti-indemnity acts may restrict or void a party's indemnification of the Company. The Company's customers and other third parties may dispute, or be unable to meet, their contractual indemnification obligations to the Company due to financial, legal or other reasons. Accordingly, the Company may be unable to transfer these risks to its customers and other third parties by contract or indemnification agreements. Incurring a liability for which the Company is not fully indemnified or insured could have a material adverse effect on its business, financial condition, cash flows and results of operations.

The Company has insurance coverage for fire, windstorm and other risks of physical loss to its rigs and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. The Company has also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, the Company generally maintains a $1.5 million per occurrence deductible on its workers' compensation insurance coverage, a $1.0 million per occurrence deductible on its equipment insurance coverage, a $2.0 million per occurrence deductible on its general liability coverage and a $2.0 million per occurrence deductible on its automobile liability insurance coverage. The Company also self-insures a number of other risks, including loss of earnings and business interruption and cyber risks, and does not carry a significant amount of insurance to cover risks of underground reservoir damage. If a significant accident or other event occurs that is not fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on the Company's business, financial condition, cash flows and results of operations.

The Company is party to various 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.

Other Matters — The Company has Change in Control Agreements with its Chairman of the Board and two of its Senior Vice Presidents (the "Specified Employees"). Each Change in Control Agreement generally has an initial term with automatic twelve-month renewals unless the Company notifies the Specified Employee at least ninety days before the end of such renewal period that the term will not be extended. If a change in control of the Company occurs during the term of the agreement and the Specified Employee's employment is terminated (i) by the Company other than for cause or other than automatically as a result of death, disability or retirement, or (ii) by the Specified Employee for good reason (as those terms are defined in the Change in Control Agreements), then the Specified Employee shall generally be entitled to, among other things:

- a bonus payment equal to the highest bonus paid after the Change in Control Agreement was entered into (such bonus payment for each Specified Employee prorated for the portion of the fiscal year preceding the termination date);
- a payment equal to 2.5 times (in the case of the Chairman of the Board) or 2 times (in the case of the Senior Vice Presidents) of the sum of (i) the highest annual salary in effect for such Specified Employee and (ii) the average of the three annual bonuses earned by the Specified Employee for the three fiscal years preceding the termination date and
- continued coverage under the Company's welfare plans for up to three years (in the case of the Chairman of the Board) or two years (in the case of the Senior Vice Presidents).

Each Change in Control Agreement provides the Specified Employee with a full gross-up payment for any excise taxes imposed on payments and benefits received under the Change in Control Agreements or otherwise, including other taxes that may be imposed as a result of the gross-up payment.

The Company has Employment Agreements with its Chief Executive Officer, General Counsel and the President of the Company's subsidiary, Patterson-UTI Drilling Company LLC ("Patterson-UTI Drilling"). In the case of the Chief Executive Officer and the General Counsel, the Employment Agreement supersedes the prior Change in Control Agreement with each executive and, in the case of the President of Patterson-UTI Drilling, the Employment Agreement supersedes his prior employment agreement. Each Employment Agreement generally has an initial three-year term, subject to automatic annual renewal. The executive may terminate his employment under his Employment Agreement by providing written notice of such termination at least 30 days before the effective date of such termination. Under specified circumstances, the Company may terminate the executive's employment under his Employment Agreement for Cause (as defined in the Employment Agreement) by either (i) providing written notice 10 days before the effective date of such termination and by granting at least 10 days to cure the cause for such termination or (ii) by providing written notice of such termination at least 30 days before the effective date of such termination and by granting at least 20 days to cure the cause for such termination, provided that if the matter is reasonably determined by the Company to not be capable of being cured, the executive may be terminated for cause on the date the written notice is delivered. The Employment Agreement also provides for, among other things, severance payments and the continuation of certain benefits following termination by the Company of the executive other than for Cause, or termination by the executive for Good Reason (as defined in each Employment Agreement). Under these provisions, if the executive's employment is terminated by the Company without Cause, or the executive terminates his employment for Good Reason:

- the executive will have the right to receive a lump-sum payment consisting of 3 times (in the case of the Chief Executive Officer) or 2.5 times (in the case of the General Counsel and President of Patterson-UTI Drilling) the sum of (i) his base salary and (ii) the average annual cash bonus received by him for the three years prior to the date of termination;
- the executive will have the right to receive a pro-rated lump-sum payment equal to his annual cash bonus based on actual results for the year, payable at the same time as annual cash bonuses are paid to active employees,
- the Company will accelerate vesting of all options and restricted stock awards on the 60th day following the executive's termination, and
- the Company will pay the executive certain accrued obligations and certain obligations pursuant to the terms of employee benefit plans.

If a termination by the Company other than for Cause or by the executive for Good Reason occurs following a Change in Control (as defined in his Employment Agreement, which for the President of Patterson-UTI Drilling includes a change in control of the Company or, in certain circumstances, of Patterson-UTI Drilling), the executive will generally be entitled to the same severance payments and benefits described above except that the pro-rated lump-sum payment for annual cash bonuses will be based on his highest annual cash bonus for the last three years, and the executive will be entitled to 36 months (in the case of the Chief Executive Officer) or 30 months (in the case of the General Counsel and President of Patterson-UTI Drilling) of subsidized benefits continuation coverage.

10. Stockholders' Equity

Cash Dividends – The Company paid cash dividends during the years ended December 31, 2016, 2015 and 2014 as follows:

	Per Share	Total (in thousands)
2016		
Paid on March 24, 2016	$0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Paid on December 22, 2016	0.02	2,961
Total cash dividends	$0.16	$ 23,579
2015		
Paid on March 25, 2015	$0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$0.40	$ 58,775
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 8, 2017, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.02 per share to be paid on March 22, 2017 to holders of record as of March 8, 2017. 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 the Company's debt agreements and other factors. The merger agreement prohibits the Company (unless consented to in advance by SSE, which consent may not be unreasonably withheld, delayed or conditioned) from paying dividends to holders of the Company's common stock in excess of $0.02 per share per quarter until the earlier of the effective time of the SSE merger and the termination of the merger agreement in accordance with its terms.

On January 27, 2017, the Company completed an offering of 18.2 million shares of its common stock and it intends to use the net proceeds from this offering of approximately $470 million to fund the repayment of SSE's outstanding net indebtedness upon closing of the SSE merger. If the SSE merger is not consummated, the Company intends to use the net proceeds of the offering for general corporate purposes, which may include repayment of outstanding indebtedness or investments in working capital.

On September 6, 2013, the Company's Board of Directors approved a 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, 2016, the Company had remaining authorization to purchase approximately $187 million of the

Company's outstanding common stock under the 2013 stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

The Company acquired shares of stock from directors during 2016 and from employees during 2016, 2015 and 2014 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. 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 years ended December 31, 2016, 2015 and 2014 were as follows (dollars in thousands):

	2016		2015		2014	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	43,207,240	$907,045	42,818,585	$899,035	42,268,057	$880,888
Purchases pursuant to 2013 stock buyback program:	8,488	183	8,618	180	13,898	466
Acquisitions pursuant to long-term incentive plans	176,889	3,866	380,037	7,830	536,630	17,681
Treasury shares at end of period	43,392,617	$911,094	43,207,240	$907,045	42,818,585	$899,035

11. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Share-based awards consist of equity instruments in the form of stock options, restricted stock or restricted stock units and have included service and, in certain cases, performance conditions. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units and share-settled performance unit awards vest.

The Company's shareholders approved the 2014 Plan, and the Board of Directors adopted a resolution that no future grants would be made under any of the Company's other previously existing plans. The Company's share-based compensation plans at December 31, 2016 are as follows:

Plan Name	Shares Authorized for Grant	Shares Underlying Awards Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan	9,100,000	3,851,760	1,784,452
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	—	4,454,500	—

A summary of the 2014 Plan follows:

- The Compensation Committee of the Board of Directors administers the plan other than the awards to directors.
- All employees, officers and directors are eligible for awards.
- The Compensation Committee determines the vesting schedule for awards. Awards typically vest over one year for non-employee directors and three years for employees.
- The Compensation Committee sets the term of awards and no option term can exceed 10 years.
- All options granted under the plan are granted with an exercise price equal to or greater than the fair market value of the Company's common stock at the time the option is granted.
- The plan provides for awards of incentive stock options, non-incentive stock options, tandem and freestanding stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit

awards and dividend equivalents. As of December 31, 2016, non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the plan.

Options granted under the 2005 Plan typically vested over one year for non-employee directors and three years for employees. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant. Restricted stock awards granted under the 2005 Plan typically vested over one year for non-employee directors and three years for employees.

Stock Options—The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate grant date fair values for stock options granted during the years ended December 31, 2016, 2015 and 2014 are as follows:

	2016	2015	2014
Volatility	35.11 %	37.95 %	35.89 %
Expected term (in years)	5.00	5.00	5.00
Dividend yield	2.05 %	2.00 %	1.17 %
Risk-free interest rate	1.40 %	1.37 %	1.76 %

Stock option activity for the year ended December 31, 2016 follows:

	Shares	Weighted-average exercise price
Outstanding at beginning of year	6,307,250	$ 21.68
Granted	969,900	$ 18.40
Exercised	(40,000)	$ 17.69
Expired	(550,000)	$ 28.26
Outstanding at end of year	6,687,150	$ 20.68
Exercisable at end of year	5,326,606	$ 21.01

Options outstanding at December 31, 2016 have an aggregate intrinsic value of approximately $46.8 million and a weighted-average remaining contractual term of 5.13 years. Options exercisable at December 31, 2016 have an aggregate intrinsic value of approximately $36.2 million and a weighted-average remaining contractual term of 4.15 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2016, 2015 and 2014 follows:

	2016	2015	2014
Weighted-average grant date fair value of stock options granted (per share)	$4.90	$5.79	$9.81
Aggregate grant date fair value of stock options vested during the year (in thousands)	$4,729	$5,077	$5,173
Aggregate intrinsic value of stock options exercised (in thousands)	$366	$—	$21,862

As of December 31, 2016, options to purchase 1.4 million shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2016 with respect to these non-vested options follows:

Aggregate intrinsic value (in thousands)	$10.5 million
Weighted-average remaining contractual term	9.0 years
Weighted-average remaining expected term	4.0 years
Weighted-average remaining vesting period	2.0 years
Unrecognized compensation cost	$6.0 million

Restricted Stock—For all restricted stock awards to date, shares of common stock were issued when the awards were made. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested shares of restricted stock. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity for the year ended December 31, 2016 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,432,250	$ 24.56
Granted	785,486	$ 20.58
Vested	(747,029)	$ 24.77
Forfeited	(43,252)	$ 24.57
Non-vested restricted stock outstanding at end of year	1,427,455	$ 22.26

As of December 31, 2016, approximately 1.3 million shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2016 with respect to these non-vested shares follows:

Aggregate intrinsic value	$34.0 million
Weighted-average remaining vesting period	1.8 years
Unrecognized compensation cost	$21.3 million

Restricted Stock Units—For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on certain non-vested restricted stock units. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock unit activity for the year ended December 31, 2016 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock units outstanding at beginning of year	41,686	$ 26.22
Granted	178,254	$ 19.31
Vested	(15,033)	$ 27.30
Forfeited	(13,252)	$ 24.08
Non-vested restricted stock units outstanding at end of year	191,655	$ 19.85

Performance Unit Awards. The Company has granted stock-settled performance unit awards to certain executive officers (the “Performance Units”) on an annual basis since 2010. The Performance Units provide for the recipients to receive a grant of shares of stock upon the achievement of certain performance goals during a specified period established by the Compensation Committee. The performance period for the Performance Units is the three year period commencing on April 1 of the year of grant, except that for the Performance Units granted in 2013 the performance period was extended pursuant to its terms, as described below.

The performance goals for the Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards and the market conditions were factored into the determination of the fair value of the respective performance units. Generally, the recipients will receive a target number of shares if the Company's total shareholder return is positive and, when compared to the peer group, is at the 50^{th} percentile. If the Company's total shareholder return during the performance period is positive and, when compared to the peer group, is at the 75^{th} percentile or higher, then the recipients will receive two times the target number of shares. If the Company's total shareholder return is positive and, when compared to the peer group, is at the 25^{th} percentile, the recipients will only receive one-half of the target number of shares. If the Company's total shareholder return during the performance period is positive and, when compared to the peer group, is between the 25^{th} and 75^{th} percentile, then the shares to be received by the recipients will be determined on a pro-rata basis. For the Performance Units awarded prior to 2016, there is no payout unless the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25^{th} percentile.

For the Performance Units granted in April 2016, if the Company's total shareholder return is negative and, when compared to the peer group, is at or above the 25^{th} percentile, then the recipients will receive one-half of the number of shares they would have received had the Company's total shareholder return been positive.

In respect of the 2013 Performance Units, for which the performance period ended March 31, 2016, the Company's total shareholder return for the performance period was negative, the Company's total shareholder return for the performance period when compared to the peer group was above the 75th percentile, and there was no payout; provided, however, that pursuant to the terms of those 2013 awards, if, during the two-year period ending March 31, 2018, the Company's total shareholder return for any 30 consecutive day period equals or exceeds 18 percent on an annualized basis from April 1, 2013 through the last day of such 30 consecutive day period, and the recipient is actively employed by the Company through the last day of the extended performance period, then the Company will issue to the recipient the number of shares equal to the amount the recipient would have been entitled to receive had the Company's total shareholder return been positive during the initial three year performance period.

The total target number of shares with respect to the Performance Units for the years 2011-2016 is set forth below:

	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards
Target number of shares	185,000	190,600	154,000	236,500	192,000	144,375

For the Performance Units that have been settled, the total shareholder return percentiles and the number of shares issued are as follows:

	2012 Performance Unit Awards	2011 Performance Unit Awards
Total shareholder return percentile for performance period	87th	94th
Shares issued	384,000	288,750

Because the Performance Units are stock-settled awards, they are accounted for as equity awards and measured at fair value on the date of grant using a Monte Carlo simulation model. The fair value of the Performance Units is set forth below (in thousands):

	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards
Aggregate fair value at date of grant	$ 3,854	$ 4,052	$ 5,388	$ 5,564	$ 3,065	$ 5,569

These fair value amounts are charged to expense on a straight-line basis over the performance period. Compensation expense associated with the Performance Units is set forth below (in thousands):

	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards
Year ended December 31, 2016	$ 963	$ 1,351	$ 1,796	$ 464	NA	NA
Year ended December 31, 2015	NA	$ 1,013	$ 1,796	$ 1,855	$ 255	NA
Year ended December 31, 2014	NA	NA	$ 1,347	$ 1,855	$ 1,022	$ 464

Dividends on Equity Awards – Non-forfeitable cash dividends are paid on restricted stock awards and dividend equivalents are paid on certain restricted stock units. These payments are recognized as follows:

- Dividends are recognized as reductions of retained earnings for the portion of restricted stock awards expected to vest.
- Dividends are recognized as additional compensation cost for the portion of restricted stock awards that are not expected to vest or that ultimately do not vest.
- Dividend equivalents are recognized as additional compensation cost for restricted stock units.

12. Leases

The Company incurred rent expense of $25.3 million, $37.6 million and $51.9 million for the years ended December 31, 2016, 2015 and 2014, respectively. Rent expense is primarily related to short-term equipment rentals that are generally passed through to customers.

Future minimum rental payments required under operating leases having initial or remaining non-cancelable lease terms in excess of one year at December 31, 2016 are as follows:

Year ending December 31,	
2017	$5,707
2018	4,991
2019	4,524
2020	3,864
2021	2,822
Thereafter	9,145
Total	$31,053

13. Income Taxes

Components of the income tax provision applicable to federal, state and foreign income taxes for the years ended December 31, 2016, 2015 and 2014 are as follows (in thousands):

	2016	2015	2014
Federal income tax expense (benefit):			
Current	$(24,777)	$(42,020)	$39,438
Deferred	(134,592)	(83,812)	39,673
	(159,369)	(125,832)	79,111
State income tax expense (benefit):			
Current	(257)	(3,480)	3,987
Deferred	(14,163)	(12,433)	5,292
	(14,420)	(15,913)	9,279
Foreign income tax expense (benefit):			
Current	(368)	(2,590)	4,521
Deferred	(3,405)	(3,628)	(1,292)
	(3,773)	(6,218)	3,229
Total income tax expense (benefit):			
Current	(25,402)	(48,090)	47,946
Deferred	(152,160)	(99,873)	43,673
Total income tax expense (benefit):	$(177,562)	$(147,963)	$91,619

The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2016, 2015 and 2014 is summarized as follows:

	2016	2015	2014
Statutory tax rate	35.0 %	35.0 %	35.0 %
State income taxes	2.0	2.1	2.5
Permanent differences	(0.1)	(1.3)	(1.4)
Other differences, net	(1.1)	(2.4)	(0.1)
Effective tax rate	35.8 %	33.4 %	36.0 %

The lower 2015 effective tax rate is primarily related to the impact of goodwill impairment charges in 2015, along with an adjustment to the Company's deferred tax liability associated with the 2010 conversion of its Canadian operations to a controlled foreign corporation.

The tax effect of significant temporary differences representing deferred tax assets and liabilities at December 31, 2016 and 2015 are as follows (in thousands):

	2016	2015
Deferred tax assets:		
Current:		
Net operating loss carryforwards	$4,702	$27,887
Workers' compensation allowance	25,736	28,734
Other	16,710	21,305
	47,148	77,926
Non-current:		
Net operating loss carryforwards	198,783	77,514
AMT credit	7,907	—
Expense associated with employee stock options	14,443	14,591
Federal benefit of state deferred tax liabilities	23,026	24,485
Other	19,137	20,441
	263,296	137,031
Less:		
Allowance to reduce deferred tax asset to expected realizable value	—	(603)
Total deferred tax assets	310,444	214,354
Deferred tax liabilities:		
Current:		
Other	(10,709)	(12,805)
Non-current:		
Property and equipment basis difference	(929,483)	(986,922)
Other	(16,789)	(13,339)
	(946,272)	(1,000,261)
Total deferred tax liabilities	(956,981)	(1,013,066)
Net deferred tax liability	$(646,537)	$(798,712)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized, and necessary allowances are provided. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. The Company expects the carrying value of its deferred tax assets at December 31, 2016 and 2015 to be realized as a result of the reversal of existing taxable temporary differences giving rise to deferred tax liabilities, as well as the generation of taxable income in future periods. As of December 31, 2016 the Company does not consider a valuation allowance necessary. The valuation allowance of $603,000 related to state net operating losses that expired in 2016.

Other deferred tax assets consist primarily of the tax effect of various allowance accounts and tax-deferred expenses expected to generate future tax benefits of approximately $35.8 million. Other deferred tax liabilities consist primarily of the tax effect of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

For income tax purposes, the Company has approximately $484 million of federal net operating losses, approximately $16 million of Canadian net operating losses and approximately $389 million, of state net operating losses as of December 31, 2016. Of these amounts, approximately $16 million of Canadian and $5 million of state losses will be carried back to prior years and the remaining balance can be carried forward to future years. Net operating losses that can be carried forward, if unused, are scheduled to expire as follows: 2025—$2.8 million; 2026—$17.1 million; 2027—$102,000; 2029—$33.2 million; 2030—$28.6 million; 2031—$92.0 million; 2034—$30,000; 2035—$302.6 million, 2 $391.1 million.

As of December 31, 2016, the Company had no unrecognized tax benefits. The Company has established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2016, the tax years ended December 31, 2013 through December 31, 2015 are open for examination by U.S. taxing authorities. As of December 31, 2016, the tax years ended December 31, 2012 through December 31, 2015 are open for examination by Canadian taxing authorities.

On January 1, 2010, the Company converted its Canadian operations from a Canadian branch to a controlled foreign corporation for federal income tax purposes. This transaction triggered a $1.0 million increase in deferred tax liabilities, which is being amortized as an increase to deferred income tax expense over the weighted average remaining useful life of the Canadian assets. This amount was fully amortized as of December 31, 2016.

As a result of the above conversion, the Company's Canadian assets are no longer directly subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, the Company has elected to permanently reinvest these unremitted earnings in Canada, and it intends to do so for the foreseeable future. As a result, no deferred United States federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $18.8 million as of December 31, 2016. The unrecognized deferred tax liability associated with these earnings was approximately $2.5 million, net of available foreign tax credits. This liability would be recognized if the Company received a dividend of the unremitted earnings.

14. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $4.4 million in 2016, $7.1 million in 2015 and $7.2 million in 2014 for the Company's contributions to the plan.

15. Business Segments

The Company's revenues, operating profits and identifiable assets are primarily attributable to two business segments: (i) contract drilling of oil and natural gas wells and (ii) pressure pumping services. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2016, the Company had 202 marketed land-based drilling rigs in the continental United States and western Canada.

For the years ended December 31, 2016, 2015 and, 2014, contract drilling revenue earned in Canada was $15.6 million, $37.5 million and $87.5 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totaled $44.0 million and $53.4 million as of December 31, 2016 and 2015, respectively.

Pressure Pumping — The Company provides pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. Pressure pumping services are primarily well stimulation services (such as hydraulic fracturing) and cementing services for the completion of new wells and remedial work on existing wells. Well stimulation involves processes inside a well designed to enhance the flow of oil, natural gas, or other desired substances from the well. Cementing is the process of inserting material between the hole and the pipe to center and stabilize the pipe in the hole.

Major Customer — During 2016, one customer accounted for approximately $124 million or 14% of the Company's consolidated operating revenues. During 2015, one customer accounted for approximately $244 million or 13% of the Company's consolidated operating revenues. These revenues were earned in both the Company's contract drilling and pressure pumping businesses. During 2014, no single customer accounted for more than 10% of the Company's consolidated operating revenue.

The following tables summarize selected financial information relating to the Company’s business segments (in thousands):

	Years Ended December 31,		
	2016	2015	2014
Revenues:			
Contract drilling	$544,196	$1,155,565	$1,843,707
Pressure pumping	354,070	712,454	1,294,569
Other operations(a)	18,299	24,931	50,196
Elimination of intercompany revenues(b)	(699)	(1,673)	(6,181)
Total revenues	$915,866	$1,891,277	$3,182,291
Income (loss) before income taxes:			
Contract drilling	$(235,858)	$(78,970)	$241,851
Pressure pumping	(176,628)	(254,998)	89,081
Other operations	(3,391)	(14,269)	(6,738)
Corporate	(54,672)	(57,088)	(56,849)
Other operating income (expense), net (c)	14,323	(1,647)	15,781
Interest income	327	964	979
Interest expense	(40,366)	(36,475)	(29,825)
Other	69	34	3
Income (loss) before income taxes	$(496,196)	$(442,449)	$254,283
Identifiable assets:			
Contract drilling	$3,032,819	$3,457,044	$4,000,576
Pressure pumping	653,630	813,704	1,186,010
Other operations	48,885	38,726	51,313
Corporate(d)	69,272	220,010	153,013
Total assets	$3,804,606	$4,529,484	$5,390,912
Depreciation, depletion, amortization and impairment:			
Contract drilling	$467,974	$618,434	$524,023
Pressure pumping	184,872	214,552	147,595
Other operations	10,114	26,301	42,576
Corporate	5,474	5,472	4,536
Total depreciation, depletion, amortization and impairment	$668,434	$864,759	$718,730
Capital expenditures:			
Contract drilling	$72,508	$527,054	$771,593
Pressure pumping	39,584	197,577	241,359
Other operations	6,116	16,625	36,683
Corporate	1,591	2,520	2,706
Total capital expenditures	$119,799	$743,776	$1,052,341

(a) Other operations includes the Company’s pipe handling components and related technology business, the oil and natural gas working interests and the Middle East/North Africa business.

(b) Consists of contract drilling and, in 2016, intercompany revenues between the pipe handling component manufacturer and the pipe handling component service provider, and in 2014, pressure pumping intercompany revenues for services provided to the oil and natural gas exploration and production segment.

(c) Other operating income (expense), net includes net gains or losses associated with the disposal of assets relate to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments. This caption also includes expenses related to certain legal settlements net of insurance reimbursements.

(d) Corporate assets primarily include cash on hand, income tax receivables and certain deferred tax assets.

16. Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of demand deposits, temporary cash investments and trade receivables.

The Company believes it has placed its demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2016 and 2015, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2016	2015
Deposits in FDIC and SIPC-insured institutions under insurance limits	$846	$617
Deposits in FDIC and SIPC-insured institutions over insurance limits	12,866	130,330
Deposits in foreign banks	27,557	15,303
	41,269	146,250
Less outstanding checks and other reconciling items	(6,117)	(32,904)
Cash and cash equivalents	$35,152	$113,346

Concentrations of credit risk with respect to trade receivables are primarily focused on companies involved in the exploration and development of oil and natural gas properties. The concentration is somewhat mitigated by the diversification of customers for which the Company provides services. As is general industry practice, the Company typically does not require customers to provide collateral. No significant losses from individual customers were experienced during the years ended December 31, 2016, 2015 or 2014. No provision for bad debts was recognized in 2016, 2015 or 2014.

17. Fair Values of Financial Instruments

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items. These fair value estimates are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting.

The estimated fair value of the Company's outstanding debt balances (including current portion) as of December 31, 2016 and 2015 is set forth below (in thousands):

	December 31, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Revolving credit facility	$—	$—	$—	$—
Term loan facility	—	—	70,000	70,000
2015 Term Loan	—	—	185,000	185,000
4.97% Series A Senior Notes	300,000	283,534	300,000	279,635
4.27% Series B Senior Notes	300,000	263,194	300,000	258,806

Total debt	$600,000	$546,728	$855,000	$793,441

The carrying values of the balances outstanding under the revolving credit facility, the term loan facility, and the 2015 Term Loan approximate their fair values as these instruments have floating interest rates. The fair values of the Series A Notes and Series B Notes at December 31, 2016 and 2015 are based on discounted cash flows associated with the respective notes using current market rates of interest at those respective dates. For the Series A Notes, the current market rates used in measuring this fair value were 6.65% at December 31, 2016 and 6.66% at December 31, 2015. For the Series B Notes, the current market rates used in measuring this fair value were 7.02% at December 31, 2016 and 6.95% at December 31, 2015. These fair value estimates are based on observable market inputs and are considered Level 2 fair value estimates in the fair value hierarchy of fair value accounting.

18. Quarterly Financial Information (in thousands, except per share amounts) (unaudited)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2016				
Operating revenues	$268,939	$193,907	$206,133	$246,887
Operating loss	(95,259)	(124,332)	(123,409)	(113,226)
Net loss	(70,503)	(85,866)	(84,143)	(78,122)
Net loss per common share:				
Basic	$(0.48)	$(0.58)	$(0.58)	$(0.53)
Diluted	$(0.48)	$(0.58)	$(0.58)	$(0.53)
2015				
Operating revenues	$657,699	$472,761	$422,251	$338,566
Operating income (loss)	24,103	(24,764)	(329,515)	(76,796)
Net income (loss)	9,125	(18,975)	(225,978)	(58,658)
Net income (loss) per common share:				
Basic	$0.06	$(0.13)	$(1.54)	$(0.40)
Diluted	$0.06	$(0.13)	$(1.54)	$(0.40)

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Charged to Costs and Expenses	Deductions(1)	Ending Balance
	(In thousands)			
Year Ended December 31, 2016				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,545	$ —	$ (354)	$3,191
Year Ended December 31, 2015				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,546	$ —	$ (1)	$3,545
Year Ended December 31, 2014				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,674	$ —	$ (128)	$3,546

(1) Consists of uncollectible accounts written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Patterson-UTI Energy, Inc. has duly caused this Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

PATTERSON-UTI ENERGY, INC.

By: /s/ William Andrew Hendricks, Jr.
William Andrew Hendricks, Jr.
President and Chief Executive Officer

Date: February 13, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report on Form 10-K has been signed by the following persons on behalf of Patterson-UTI Energy, Inc. and in the capacities indicated as of February 13, 2017.

Signature	Title
/s/ Mark S. Siegel Mark S. Siegel	Chairman of the Board
/s/ William Andrew Hendricks, Jr. William Andrew Hendricks, Jr. (Principal Executive Officer)	President and Chief Executive Officer
/s/ John E. Vollmer III John E. Vollmer III (Principal Financial and Accounting Officer)	Senior Vice President — Corporate Development, Chief Financial Officer and Treasurer
/s/ Kenneth N. Berns Kenneth N. Berns	Senior Vice President and Director
/s/ Charles O. Buckner Charles O. Buckner	Director
/s/ Michael W. Conlon Michael W. Conlon	Director
/s/ Curtis W. Huff Curtis W. Huff	Director
/s/ Terry H. Hunt Terry H. Hunt	Director
/s/ Tiffany J. Thom Tiffany J. Thom	Director

EXHIBIT INDEX

2.1 Agreement and Plan of Merger by and among Patterson-UTI Energy, Inc., Pyramid Merger Sub, Inc. and Seventy Seven Energy Inc., dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 2.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

3.1 Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.2 Certificate of Amendment to the Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.3 Certificate of Elimination with respect to Series A Participating Preferred Stock (filed October 27, 2011 as Exhibit 3.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

3.4 Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).

10.1 Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned to REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).

10.2 Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 21, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.3 First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.4 Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.5 Third Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.6 Fourth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.7 Fifth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*

10.8 Form of Share-Settled Performance Unit Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 and incorporated herein by reference).*

10.9 Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (filed April 21, 2014 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.10 Form of Executive Officer Share-Settled Performance Share Award Agreement (filed April 21, 2014 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.11 Form of Executive Officer Share-Settled Performance Share Award Agreement (filed May 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*

10.12 Form of Executive Officer Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.13 Form of Executive Officer Restricted Stock Award Agreement (filed May 2, 2016 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*

10.14 Form of Executive Officer Stock Option Agreement (filed April 21, 2014 as Exhibit 10.4 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.15 Form of Non-Employee Director Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.5 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.16 Form of Non-Employee Director Stock Option Agreement (filed April 21, 2014 as Exhibit 10.6 to the Company's Current

Report on Form 8-K and incorporated herein by reference).*

10.17 Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (filed on February 25, 2005 as Exhibit 10.23 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*

10.18 Employment Agreement, effective as of January 1, 2017, by and between Patterson-UTI Drilling Company LLC and James M. Holcomb (filed January 17, 2017 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference). *

10.19 Employment Agreement, effective as of August 1, 2016, by and between Patterson-UTI Energy, Inc. and William Andrew Hendricks, Jr. (filed August 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference). *

10.20 Employment Agreement, effective as of January 1, 2017, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler.*+

10.21 Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon and Tiffany J. Thom (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*

10.22 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.23 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.24 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.25 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.26 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.27 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company's Quarterly

Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.28 Credit Agreement dated September 27, 2012, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed September 28, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.29 Amendment No. 1 to Credit Agreement dated as of January 9, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed January 12, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.30 Amendment No. 2 to Credit Agreement dated as of July 8, 2016, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed July 12, 2016 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.31 Amendment No. 3 to Credit Agreement dated as of January 17, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto.+

10.32 Commitment Increase Agreement, dated as of January 24, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed January 24, 2017 as Exhibit 10.1 to the Company's Current Report on Form 8-K and

incorporated herein by reference).

10.33 Note Purchase Agreement dated October 5, 2010 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed October 6, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.34 Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010) (filed October 28, 2015 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

10.35 Note Purchase Agreement dated June 14, 2012 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed June 18, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.36 Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012) (filed October 28, 2015 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

10.37 Reimbursement Agreement, dated as March 16, 2015, by and between Patterson-UTI Energy, Inc. and The Bank of Nova Scotia (filed March 16, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.38 Continuing Guaranty, dated as of March 16, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 16, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.39 Term Loan Agreement, dated as March 18, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents (filed March 18, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.40 Continuing Guaranty, dated as of March 18, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 18, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.41 Commitment Letter, dated December 12, 2016, between Patterson-UTI Energy, Inc. and Canyon Capital Advisors LLC (filed December 13, 2016 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.42	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Axar Capital Management, LLC, dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.43	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Blue Mountain Capital Management, LLC, dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.44	Voting and Support Agreement, by and among Patterson-UTI Energy, Inc. and certain affiliates of Mudrick Capital Management, L.P., dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 10.4 to the Company's Current Report on Form 8-K and incorporated herein by reference).
21.1	Subsidiaries of the Registrant.+
23.1	Consent of Independent Registered Public Accounting Firm.+
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.+
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.+
32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.+
101	The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, and (vi) Notes to Consolidated Financial Statements.+

* Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.
+ Filed herewith.