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, 2020

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ________ to ________

Commission File Number 1-39270

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	Trading Symbol	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	PTEN	The Nasdaq Global Select Market
Preferred Stock Purchase Rights		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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒or No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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, 2020, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $639 million, calculated by reference to the closing price of $3.47 for the common stock on the Nasdaq Global Select Market on that date.

As of February 4, 2021, the registrant had outstanding 187,736,421 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 2021 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, press releases and presentations 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. As used in this Report, "we," "us," "our," "ours" and like terms refer collectively to Patterson-UTI Energy, Inc. and its consolidated subsidiaries. Patterson-UTI Energy, Inc. conducts its operations through its wholly-owned subsidiaries and has no employees or independent business operations. These forward-looking statements involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue, cost and margin expectations and backlog; financing of operations; oil and natural gas prices; rig counts and frac spreads; source and sufficiency of funds required for building new equipment, upgrading existing equipment and acquisitions (if opportunities arise); demand and pricing for our services; competition; equipment availability; government regulation; legal proceedings; debt service obligations; impact of inflation; 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," "strategy," "target," or "will," 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.

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:

- adverse oil and natural gas industry conditions; including the rapid decline in crude oil prices as a result of economic repercussions from the COVID-19 pandemic;
- global economic conditions;
- 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;
- excess availability of land drilling rigs, pressure pumping and directional drilling equipment, including as a result of reactivation, improvement or construction;
- competition and demand for our services;
- strength and financial resources of competitors;
- utilization, margins and planned capital expenditures;
- liabilities from operational risks for which we do not have and receive full indemnification or insurance;
- 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);
- the ability to realize backlog;
- specialization of methods, equipment and services and new technologies, including the ability to develop and obtain satisfactory returns from new technology;

- the ability to retain management and field personnel;
- loss of key customers;
- shortages, delays in delivery, and interruptions in supply, of equipment and materials;
- cybersecurity events;
- synergies, costs and financial and operating impacts of acquisitions;
- difficulty in building and deploying new equipment;
- governmental regulation;
- climate legislation, regulation and other related risks;
- environmental, social and governance practices, including the perception thereof;
- environmental risks and ability to satisfy future environmental costs;
- technology-related disputes;
- legal proceedings and actions by governmental or other regulatory agencies;
- the ability to effectively identify and enter new markets;
- weather;
- operating costs;
- expansion and development trends of the oil and natural gas industry;
- ability to obtain insurance coverage on commercially reasonable terms;
- financial flexibility;
- interest rate volatility;
- adverse credit and equity market conditions;
- availability of capital and the ability to repay indebtedness when due;
- stock price volatility;
- compliance with covenants under our debt agreements; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our filings with the SEC.

We caution that the foregoing list of factors is not exhaustive. Additional information concerning these and other risk factors is contained in this Report and may be contained in our future filings with the SEC. You are cautioned not to place undue reliance on any of our forward-looking statements. 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 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. 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 one of the largest fleets of land-based drilling rigs in the United States and a large fleet of pressure pumping equipment.

Our contract drilling business operates in the continental United States and, from time to time, we pursue contract drilling opportunities in other select markets. As of December 31, 2020, we had a drilling fleet that consisted of 210 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. Substantially all of the revenue in the pressure pumping segment is from well stimulation services (such as hydraulic fracturing) for 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. As of December 31, 2020, we had approximately 1.3 million fracturing horsepower to provide these services. We also provide cementing services through the pressure pumping segment. Cementing is the process of inserting material between the wall of the well bore and the casing to support and stabilize the casing. 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 provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States. Our directional drilling services include directional drilling, measurement-while-drilling and supply and rental of downhole performance motors and wireline steering tools. We also provide services that improve the statistical accuracy of horizontal wellbore placement.

We have other operations through which we provide oilfield rental tools in select markets in the United States. We also service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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

Recent Developments in Market Conditions — Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2018, 2019 and 2020 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2018:				
Average oil price per Bbl (1)	$62.88	$68.04	$69.76	$59.08
Average rigs operating per day — U.S. (2)	166	175	177	182
2019:				
Average oil price per Bbl (1)	$54.83	$59.78	$56.37	$56.94
Average rigs operating per day — U.S. (2)	174	157	142	122
2020:				
Average oil price per Bbl (1)	$45.76	$27.81	$40.89	$42.45
Average rigs operating per day — U.S. (2)	123	82	60	62

(1) The average oil price represents the average monthly West Texas Intermediate (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.

Reduced demand for crude oil and refined products related to the COVID-19 pandemic led to a significant reduction in crude oil prices and demand for drilling and completion services in the United States.

Oil prices remain extremely volatile, as the closing price of oil (WTI-Cushing) reached a first quarter 2020 high of $63.27 per barrel on January 6, 2020, declined to negative $36.98 per barrel on April 20, 2020, and closed at $53.55 per barrel on February 1, 2021. In response to the rapid decline in commodity prices, E&P companies acted swiftly to reduce drilling and completion activity starting late in the first quarter of 2020. While oil prices have recovered from the lows experienced in the first half of 2020, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our pressure pumping horsepower remains stacked. Oil prices averaged $42.45 per barrel in the fourth quarter of 2020.

Our active rig count has declined since the fourth quarter of 2018. Our average active rig count for the fourth quarter of 2020 was 62 rigs. This was an increase from our average active rig count for the third quarter of 2020 of 60 rigs. Our U.S. active rig count at December 31, 2020 of 65 rigs was less than the rig count of 121 rigs at December 31, 2019, due to the significantly reduced demand for drilling services in the United States. Term contracts help support our operating rig count. Based on contracts currently in place, we expect an average of 42 rigs operating under term contracts during the first quarter of 2021 and an average of 34 rigs operating under term contracts throughout 2021.

The pressure pumping market remains oversupplied. In response to oversupplied market conditions, we implemented changes during the second quarter of 2020 to further streamline our operations, improve our efficiencies, and reduce our overall cost structure, while maintaining our customer service levels.

Recent Developments in Financial Matters — During the fourth quarter of 2020, we elected to repurchase portions of our 2028 Notes and 2029 Notes (as defined below) in the open market. The principal amounts retired through these transactions totaled $15.5 million related to our 2028 Notes and $0.8 million related to our 2029 Notes, plus accrued interest. We recorded corresponding gains on the extinguishment of these amounts totaling $3.4 million and $0.2 million, respectively, net of the proportional write-off of associated deferred financing costs and original issuance discounts. These gains are included in “Interest expense, net of amount capitalized” in the consolidated statements of operations.

On December 24, 2020, we elected to repay $50 million of the borrowings under our Term Loan Agreement (as defined below). As of December 31, 2020, we had $50 million in borrowings remaining under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. The maturity date of the Term Loan Agreement is June 10, 2022.

On March 27, 2020, we entered into Amendment No. 2 to Amended and Restated Credit Agreement to, among other things, extend the maturity date for $550 million of revolving credit commitments of certain lenders under the Credit Agreement (as defined below) from March 27, 2024 to March 27, 2025. We have the option, subject to certain conditions, to exercise an additional one-year extension of the maturity date.

Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" for additional detail regarding our 2028 Notes, 2029 Notes, Term Loan Agreement and Credit Agreement.

During the second quarter of 2020, we implemented a restructuring plan to improve operating margins, achieve operational efficiencies and reduce indirect support costs. The restructuring included workforce reductions, changes to management structure and facility consolidations and closures. We recorded $38.3 million of charges associated with this plan in the second quarter of 2020. In conjunction with our restructuring, we closed our Canadian drilling operations. We recorded an impairment of $8.3 million associated with that closure. We completed the restructuring plan during the third quarter of 2020 and did not incur additional expenses related to the plan.

The following table presents restructuring expenses by reportable segment for the year ended December 31, 2020 (in thousands):

	Contract Drilling	Pressure Pumping	Directional Drilling	Other Operations	Corporate	Total
Severance costs	$1,821	$ 3,460	$ 503	$501	$215	$ 6,500
Contract termination costs	—	20,373	—	—	—	20,373
Other exit costs	523	194	827	—	—	1,544
Right-of-use asset abandonments	86	7,304	1,845	—	686	9,921
Total	$2,430	$31,331	$3,175	$501	$901	$38,338

Industry Segments

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

- contract drilling services,
- pressure pumping services, and
- directional drilling services.

Our contract drilling services, pressure pumping services, and directional drilling services industry segments had operating losses in 2020, 2019 and 2018.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 17 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, 2020, we had 210 marketed land-based drilling rigs based in the following regions:

- 68 in west Texas and southeastern New Mexico,
- 19 in north central and east Texas and northern Louisiana,
- 35 in the Rocky Mountain region (Colorado, Wyoming and North Dakota),
- 23 in south Texas,
- 29 in western Oklahoma, and

• 36 in the Appalachian region (Pennsylvania, Ohio and West Virginia).

Our marketed drilling rigs have rated maximum depth capabilities ranging from approximately 13,200 feet to 24,000 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 $694 million during the last three years on capital expenditures to modify, upgrade and extend the lives of components of our drilling fleet. During fiscal years 2020, 2019 and 2018, we spent approximately $105 million, $194 million and $395 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 (we define term contracts as contracts with a duration of six months or more) or for a specified number of wells. During 2020, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 19 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.

Our drilling contracts provide for payment on a daywork basis, pursuant to which 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.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Average rigs operating per day [(1)]	82	149	177
Number of rigs operated during the year	132	189	193
Number of wells drilled during the year	1,327	2,703	3,088
Number of operating days	29,904	54,544	64,479

(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 the United States.

To address our customers' needs for drilling horizontal wells in shale and other unconventional resource plays, we have improved the capability of our drilling fleet during the last several years. 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, 2020, our marketed land-based drilling fleet was comprised of the following:

	Number of Rigs	
Classification	**Total**	**Percent Pad-Capable**
APEX® 1500 HP rigs	172	94%
APEX® 1000 HP rigs	12	100%
APEX® 2000 HP rigs	6	67%
APEX® 1400 HP rigs	5	100%
APEX® 1200 HP rigs	3	100%
Other electric rigs	12	83%
Total	210	
Average horsepower	1,458	

The U.S. land rig industry refers 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 at least a 750,000-pound hookload, a 7,500-psi circulating system, and is pad-capable. We currently estimate there are approximately 690 super-spec rigs in the United States, which includes 150 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, Ohio and West Virginia.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators, primarily in Texas and the Appalachian region (Northeast Region). Pressure pumping services consist primarily of well stimulation services (such as hydraulic fracturing) 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 and proppant under pressure into the well bore to fracture the formation. Many wells in conventional plays also receive well stimulation services. We also provide cementing services through the pressure pumping segment. The cementing process inserts material between the wall of the well bore and the casing to support and stabilize the casing. The scope and impact of our cementing services were insignificant during the fiscal years 2020, 2019 and 2018.

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.

Equipment — We have pressure pumping equipment used in providing hydraulic fracturing services as well as cementing and acid pumping services, with a total of approximately 1.4 million horsepower as of December 31, 2020. Pressure pumping equipment at December 31, 2020 included:

	Fracturing Equipment	Other Pumping Equipment	Total
Texas Region			
Number of units	401	17	418
Approximate horsepower	953,250	18,555	971,805
Northeast Region			
Number of units	167	11	178
Approximate horsepower	371,150	7,500	378,650
Other Regions			
Number of units	5	—	5
Approximate horsepower	12,250	—	12,250
Combined:			
Number of units	573	28	601
Approximate horsepower	1,336,650	26,055	1,362,705

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 may not cover all of our required supply. These supply arrangements 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.

Directional Drilling Operations

General — We generally utilize our own proprietary downhole motors and equipment to provide a comprehensive suite of directional drilling services, including directional drilling, measurement-while-drilling (MWD) and supply and rental of downhole performance motors and wireline steering tools, in most major onshore oil and natural gas basins in the United States. We generally design, assemble and maintain our own fleet of downhole drilling motors and MWD equipment. Our customers primarily consist of major integrated energy companies and large North American independent oil and natural gas operators. We believe our customers use our services because of the quality of our specialized, technology-driven equipment and our well-trained and experienced workforce, which enable us to provide our customers with high-quality, reliable and safe directional drilling services.

Directional Drilling Services — We provide our directional drilling services on a dayrate basis, typically under master service agreements. Revenue from directional drilling services is recognized as work progresses based on the number of days of work completed. Our dayrates and other charges generally vary by location and depend on the equipment and personnel required for the job and market conditions in the region in which the services are performed. In addition to rates that are charged during periods of active directional drilling, a standby rate is typically agreed upon in advance and charged on a daily basis during periods when drilling is temporarily suspended while other on-site activity is conducted at the direction of the operator or another service provider.

Equipment — We generally design, assemble, maintain and inspect our own equipment. We have developed proprietary equipment for our drilling motors, mud pulse and electromagnetic data transfer MWD equipment. We believe that our vertical integration strategy allows us to deliver better operational performance and higher equipment reliability to our customers. Vertical integration also allows us to build our tools more efficiently and at a lower cost than if purchased from third parties. In addition, we have the ability to upgrade our tools in response to market conditions or our customers' job requirements, which allows us to minimize the costs and delays associated with sending equipment to original manufacturers. Our internal maintenance capability also affords us enhanced control over our supply chain and increases the effective utilization of our assets. As of December 31, 2020, we had a comprehensive fleet of over 1,000 motors. In addition to our motor fleet, we had over 100 MWD systems.

Wellbore Placement Data Analytics — We provide software and services used to improve the statistical accuracy of horizontal wellbore placement. Our measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well. Our HiFi Nav™ offering enhances FDIR by targeting improved vertical placement of the directional well within the reservoir. We provide these services to customers with onshore and offshore operations.

Other Operations

Our oilfield rentals business has a fleet of premium rental tools and provides specialized services for land-based oil and natural gas drilling, completion and workover activities in many of the major producing onshore oil and gas basins in the United States. We service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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.

Contracts

We believe that our contract drilling, pressure pumping, directional drilling and other contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations. However, each contract contains the actual terms setting forth our rights and obligations and those of the customer or supplier, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer or supplier requirements, applicable law or other factors.

Customers

Our customer base includes major, independent and other oil and natural gas operators. With respect to our consolidated operating revenues in 2020, we received approximately 54% from our ten largest customers and approximately 35% from our five largest customers. During 2020, no customer accounted for more than 10% of our consolidated operating revenues. 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.

Backlog

Our contract drilling backlog as of December 31, 2020 and 2019 was approximately $301 million and $605 million, respectively. Approximately 21% of the total contract drilling backlog at December 31, 2020 is reasonably expected to remain after 2021. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" included as a part of Item 7 of this Report for information pertaining to backlog.

Competition

The businesses in which we operate are highly competitive. Historically, available equipment used in our contract drilling, pressure pumping and directional drilling businesses has frequently exceeded demand, particularly in an industry downturn. The price for our services is a key competitive factor, in part because equipment used in these 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 our services will continue to be highly competitive.

Human Capital and Sustainability

We strive to be a leader in our industry in the area of environmental, social, governance and other sustainability-related issues, and we remain committed to managing these issues for the long-term benefit of our employees, communities and our business. We aim to minimize our environmental impact in the communities in which we work and live, while providing services for our customers in a safe and responsible manner. We invest extensively in the safety, health and well-being of our people, who are our most important asset and our greatest strength. Importantly, we maintain a rigorous focus on ethics and integrity at every level of our operations, a practice on which all of our success depends.

We encourage you to review our latest Sustainability Report, located on our website, for more detailed information regarding our Sustainability and Human Capital programs and initiatives. Nothing on our website, including our Sustainability Report or sections thereof, shall be deemed incorporated by reference into this Report or other filings that we make with the SEC.

Environment – We continue to pursue initiatives to mitigate climate change risk and make improvements in air quality, water quality, land usage, use of energy and reducing waste materials. For example, we utilize natural gas engines, dual-fuel equipment and other technologies that reduce our carbon and other greenhouse gas emissions, and we employ spill prevention plans and use additional protective measures in environmentally sensitive areas.

We have strengthened our position as a leader in alternative fuel technology with the commercialization of our EcoCell™ lithium battery hybrid energy management system. EcoCell™ is capable of efficiently displacing one of the gensets on a drilling rig to reduce both fuel consumption and emissions. The value of this technology is enhanced when used in combination with our Cortex® power management system and our dual-fuel engines, as the natural gas substitution rate can be optimized.

Through our Current Power business, we provide in-house electrical engineering, control system automation and installation services to connect drilling rigs to utility electrical lines. This capability enables our customers to use utility power, instead of natural gas or diesel fuel, to power drilling operations. Using utility power is an optimal power solution for our drilling rigs as it minimizes emission impacts at the wellsite.

Some of our key human capital areas of focus include:

Employees – We had approximately 3,000 full-time employees as of January 31, 2021. 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.

Training and Safety – Our training programs include opportunities for employees to advance in their professional careers through intensive, multi-day classroom training programs in numerous skills and competencies as well as management training programs. These programs are geared to providing our employees with opportunities to advance throughout our company.

The safety of our employees and others is our highest priority, as our goal is to provide an incident-free work environment. We have robust safety training programs in place that are designed to comply with applicable laws and industry standards and to benefit our employees, communities and our business. All field-based employees are required to attend an Employee Safety Orientation, which includes classes on behavior-based safety, hazard awareness, safe systems of work, permission to work, time out for safety, energy isolation, hazard communication (HAZCOM) and material handling. In response to the COVID-19 pandemic, we implemented, and continue to implement, safety protocols at our offices, facilities and worksites. These protocols include allowing many of our office-based employees to work from home, while implementing additional safety measures for employees continuing critical on-site work.

Diversity and Inclusion – We are committed to fostering a work environment where all people feel valued and respected. We embrace our diversity of people, thoughts and talents, and combine these strengths to pursue extraordinary results for our company, our employees and our stockholders. We are committed to recruiting, hiring and retaining the highest caliber talent for our business by utilizing outreach initiatives and partnerships with a diverse group of organizations, industry associations and networks.

We require our employees to complete training on an annual basis regarding our commitment to a respectful workplace for all. Supervisors and managers are required to complete respectful workplace training to ensure they understand our expectations for them regarding their obligations to promote a work environment where all employees feel valued and respected.

Maintaining our Core Values – In 2020, we trained over 4,000 employees on our Code of Business Conduct and Ethics, which addresses conflicts of interest, confidentiality, fair dealing with others, proper use of company assets, compliance with laws, insider trading, keeping of books and records, zero tolerance for discrimination and harassment in the work environment, as well as reporting of violations.

Health and Benefits – Our health and benefits program provides for extensive preventative care and is designed to improve our employees' fitness for work, personal safety on the job and overall well-being.

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 and acidizing and related well servicing activities,
- directional drilling services,
- services that improve the statistical accuracy of horizontal wellbore placement, including for customers with offshore operations,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks and injection wells,
- servicing of equipment for drilling contractors,
- provision of electrical controls and automation, and
- our employees.

To date, applicable environmental and other 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, delay the permitting of, or related to, such operations, restrict or prohibit oil and gas development in certain areas, reduce the demand for oil and natural gas and otherwise have an adverse effect on our operations or business, and could have a material adverse effect on our business, financial condition, cash flows and results of operations. Federal, state, foreign, regional and local environmental laws, rules and regulations, including laws, rules, regulations and executive actions related to the mitigation of climate change or greenhouse gas emissions, currently apply to our operations and are likely to become more stringent in the future. Any limitation, suspension or moratorium of the services and products 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 may 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 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. The EPA issued a report on April 23, 2019, determining that no revisions were necessary. However, if changes are made to the classification of exploration and production wastes under CERCLA and/or RCRA in the future, 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 (the "Clean Water Act") and the Oil Pollution Act of 1990 (the "Oil Pollution Act"), each as amended, and implementing regulations govern:

- the prevention and permitting 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 Clean Water 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. Certain politicians have also vocalized support for a nationwide ban on hydraulic fracturing. Additional legislation or regulation could lead to operational delays or increased operating costs in the production of oil and natural gas or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or existing wells. 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 provide for our exploration and production customers, and such efforts could adversely affect our business, financial condition, cash flows and results of operations. 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."

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. We are also subject to regulation by numerous other regulatory agencies, including, but not limited to, the U.S. Department of Labor, which oversees employment practice standards.

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."

There has been an increasing focus of local, state, national and international regulatory bodies on greenhouse gas ("GHG") emissions and climate change issues. There has also been legislation proposed by U.S. lawmakers to reduce GHG emissions, as well as GHG emissions regulations enacted by the EPA, and future federal action to address climate change is likely.

President Biden and the Democratic Party, which now controls Congress, have identified climate change as a priority, and it is likely that new executive orders, regulatory action, and/or legislation targeting greenhouse gas emissions, or prohibiting, delaying or restricting oil and gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. For example, the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee, and President Biden recently announced a moratorium on new oil and gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of Federal oil and gas permitting and leasing practices. President Biden's order also established climate change as a primary foreign policy and national security consideration, affirms that achieving net-zero greenhouse gas emissions by or before midcentury is a critical priority, affirms the Biden Administration's desire to establish the United States as a leader in addressing climate change, generally further integrates climate change and environmental justice considerations into government agencies' decision-making, and eliminates fossil fuel subsidies, among other measures. President Biden also announced that the United States is taking steps to reenter the Paris Agreement.

Several states and geographic regions in the United States have also adopted legislation and regulations to reduce emissions of GHGs, including cap and trade regimes and commitments to contribute to meeting the goals of the Paris Agreement.

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 – Our and Our Customers' Operations are Subject to a Number of Risks Arising Out of the Threat of Climate Change That Could Result in Increased Operating and Capital Costs, Limit the Areas in Which Oil and Natural Gas Production May Occur and Reduce Demand for Our Services."

Risks and Insurance

Our operations are subject to many hazards inherent in the businesses in which we operate, including inclement weather, blowouts, explosions, fires, loss of well control, motor vehicle accidents, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving our employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause us to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to our reputation, loss of customers and an inability to obtain insurance.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our 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 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 equipment and certain other assets, such insurance does not cover the full replacement cost of such 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 $10.0 million per occurrence deductible on our general liability coverage, a $2.0 million per occurrence deductible on our primary automobile liability insurance coverage, and a $5.0 million per occurrence deductible on our excess automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and most cybersecurity risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance may 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."

Seasonality

Seasonality has not significantly affected our overall operations. Toward the end of calendar years, we have recently experienced slower activity 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.

Business and Operating Risks

The Effects of the COVID-19 Pandemic, Have Had, and Are Expected to Continue to Have, a Significant Adverse Impact on Our Business, Liquidity, Results of Operations and Financial Condition.

The effects of the COVID-19 pandemic, including related governmental actions and restrictions, have had, and are expected to continue to have, a significant adverse impact on the global economy, including the worldwide demand for oil and natural gas, and the level of demand for our services, which has impacted and is expected to continue to impact our business, liquidity, results of operations and our financial condition.

In response to the COVID-19 pandemic, governmental authorities have imposed mandatory closures, sought voluntary closures and imposed restrictions on, or advisories with respect to, travel, business operations and public gatherings or interactions. While some governmental authorities have re-opened various sectors of the economy, the ongoing COVID-19 outbreak may significantly worsen, and new strains of COVID-19 may emerge, which may cause governmental authorities to reconsider restrictions on travel, business and social activities. In the event governmental authorities retain, increase or reimpose restrictions, the re-opening of the economy may be further curtailed.

In early March 2020, OPEC+ was initially unable to reach an agreement to continue to impose limits on the production of crude oil, and shortly thereafter the World Health Organization determined the COVID-19 outbreak to be a pandemic. The convergence of these events created the unprecedented dual impact of a global oil demand decline coupled with the risk of a substantial increase in supply. In response to the rapid decline in commodity prices, exploration and production companies acted swiftly to reduce drilling and completion activity starting late in the first quarter of 2020. While oil prices have recovered from the lows experienced in the first half of 2020, customer spending has not returned to pre-pandemic levels.

Given the nature and significance of the events described above, we are not able to enumerate all potential risks to our business from the recent volatility in crude oil prices and the COVID-19 pandemic; however, we believe that in addition to the impacts described above, other current and potential impacts of these recent events include, but are not limited to:

- liquidity challenges, including impacts related to delayed customer payments and payment defaults associated with customer liquidity issues and bankruptcies;
- customers, suppliers and other third parties seeking to terminate, reject, renegotiate or otherwise avoid, and otherwise failing to perform, their contractual obligations to us;
- additional credit rating downgrades of our corporate debt and potentially higher borrowing costs in the future;
- a need to preserve liquidity, which could result in a further reduction or suspension of our quarterly dividend or a delay or change in our capital investment plan;
- cybersecurity issues, as digital technologies may become more vulnerable and experience a higher rate of cyberattacks in the current environment of remote connectivity;
- litigation risk and possible loss contingencies related to COVID-19 and its impact, including with respect to commercial contracts, employee matters and insurance arrangements;
- disruption to our supply chain for raw materials essential to our business;
- a further reduction of our workforce to adjust to market conditions, including severance payments, retention issues, and an inability to hire employees when market conditions improve;
- additional costs associated with rationalization of our portfolio of real estate facilities, including exit of leases and facility closures to align with expected activity and workforce capacity;
- additional asset impairments, along with other accounting charges;
- additional infections and quarantining of our employees and the personnel of our customers, suppliers and other third parties in areas in which we operate and delays or suspensions of operations resulting therefrom;
- additional actions undertaken by international, national, regional and local governments and health officials to contain the virus or treat its effects; and
- a structural shift in the global economy and its demand for oil and natural gas as a result of changes in the way people work, travel and interact, or in connection with a global recession or depression.

The full extent of the impact of COVID-19 on our business, liquidity, results of operations and financial condition will depend largely on future developments, including the duration and further spread of the virus, including any new strains of COVID-19, and the related impact on the oil and gas industry, the impact of governmental actions designed to prevent the spread of COVID-19 and the further development and availability of effective treatments and vaccines, all of which are highly uncertain.

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 the United States. When these expenditures decline, our business may suffer. The rapid decline in oil prices resulting from the COVID-19 pandemic and the activities of OPEC+ has caused a significant decline in both customer activity and prices for our services, which has had, and is expected to continue to have, a significant impact on our business. 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, pressure pumping and directional drilling services,
- the cost of exploring for, developing, producing and delivering oil and natural gas,
- the availability of capital for oil and natural gas industry participants, including our customers,
- the availability of and constraints in pipeline, storage and other transportation capacity in the basins in which we operate,
- the environmental, tax and other laws and governmental regulations regarding the exploration, development, production, use 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,
- increased focus by the investment community on sustainability practices in the oil and natural gas industry, and
- merger and divestiture activity among oil and natural gas producers.

In particular, our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. Oil and natural gas prices and markets can be extremely volatile. Prices, and expectations about future prices, are affected by factors such as:

- market supply and demand, including impacts on supply and demand due to economic repercussions from the COVID-19 pandemic,
- the desire and ability of the Organization of Petroleum Exporting Countries ("OPEC"), its members and other oil-producing nations, such as Russia, to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries,
- domestic and international military, political, economic, health and weather conditions, including the impacts of war or terrorist activity, pandemics and other unexpected disasters or events such as the COVID-19 pandemic,
- changes to tax, tariff and import/export regulations by the United States or other countries,
- 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 and energy sources.

All of these factors are beyond our control. Oil prices remain extremely volatile, as the closing price of oil (WTI-Cushing) reached a first quarter 2020 high of $63.27 per barrel on January 6, 2020, declined to negative $36.98 per barrel on April 20, 2020, and closed at $53.55 per barrel on February 1, 2021. In response to the rapid decline in commodity prices, E&P companies acted swiftly to reduce drilling and completion activity starting late in the first quarter of 2020. While oil prices have recovered from the lows experienced in the first half of 2020, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our pressure pumping horsepower remains stacked. Oil prices averaged $42.45 per barrel in the fourth quarter of 2020.

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, as well as our customers' ability to access sources of capital to fund their operating and capital expenditures. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices, expectations of decreases in oil and natural gas prices or a reduction in the ability of our customers to access capital would likely result in 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 historically moderate or 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.

Demand for energy and for oil and natural gas end products is highly sensitive to economic conditions; as a result, global economic conditions, indications that economic growth is slowing 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, including economic repercussions from the COVID-19 pandemic, 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. An economic slowdown or recession in the United States or in any other country that significantly affects the supply of or demand for oil or natural gas could negatively impact our operations and therefore adversely affect our results. 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, including as a result of the COVID-19 pandemic, and there is no assurance that the global economic environment, or expectations for the global economic environment, will recover in the near term or not quickly deteriorate again due to one or more factors, including due to uncertainties relating to the COVID-19 pandemic. A deterioration in the global economic environment could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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

The land drilling and pressure pumping industries in the United States 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 or capital spending reductions by our customers due to customer consolidation, to investor requirements or other reasons 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 new and upgraded drilling rigs and pressure pumping equipment. Low commodity prices and new and upgraded 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 a surplus of equipment.

Due to the recently significantly reduced demand for our services, certain of our industry competitors may initiate bankruptcy proceedings or engage in debt refinancing transactions, management changes, or other strategic initiatives in an attempt to reduce operating costs to maintain a position in the market. This could result in such competitors emerging with stronger or healthier balance sheets and, in turn, an improved ability to compete with us in the future. We may also see corporate consolidations among both our customers and competitors, which could significantly alter industry conditions and competition within the industry, and have a material adverse effect on our business, financial condition, cash flows and results of operations.

We periodically seek to increase the prices on our services to offset rising costs, earn returns on our capital investment, and otherwise generate higher returns for our stockholders. However, we operate in a very competitive industry, and we are not always successful in raising or maintaining our existing prices. With the active rig count well below the peak seen in 2014 and many rigs, including highly capable AC rigs, and pressure pumping equipment still idle, there is considerable pricing pressure in the industry. Even if we are able to increase our prices, we may not be able to do so at a rate that is sufficient to offset rising costs without adversely affecting our activity levels. The inability to maintain our pricing and to increase our pricing as costs increase could have a material adverse effect on our business, financial condition, cash flows and results of operations. 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 a surplus of equipment can cause oil and natural gas service contractors to have difficulty maintaining pricing, utilization and profit margins and, at times, result in operating losses. We cannot predict the future level of competition or surplus equipment in the oil and natural gas service businesses or the level of demand for our contract drilling, pressure pumping or directional drilling services.

The surplus of operable land drilling rigs, increasing rig specialization and surplus of pressure pumping and directional drilling equipment, which has been exacerbated by a decline in oil and natural gas prices, could affect the fair market value of our drilling, pressure pumping and directional drilling 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. For example, we recognized impairment charges of $395 million, $221 million and $277 million in 2020, 2019 and 2018, respectively.

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 businesses in which we operate, including inclement weather, blowouts, explosions, fires, loss of well control, motor vehicle accidents, equipment failure, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving our employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause us to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to our reputation, loss of customers and an inability to obtain insurance.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our 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 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 equipment and certain other assets, such insurance does not cover the full replacement cost of such 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 $10.0 million per occurrence deductible on our general liability coverage, a $2.0 million per occurrence deductible on our primary automobile liability insurance coverage, and a $5.0 million per occurrence deductible on our excess automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and most of our cybersecurity risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance may 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 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, including as a result of their bankruptcy. 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, 2020, 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 $301 million. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of our calculation of backlog. Our contract drilling backlog may decline, as fixed-term drilling contract coverage over time may not be offset by new contracts or may be reduced by price adjustments to existing 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. For these and other reasons, our contract drilling backlog may not generate sufficient liquidity for us during periods of reduced demand for our services.

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

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, including environmental performance, of drilling rigs and pressure pumping and other equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs and pressure pumping and other equipment, as well as new and improved technology, such as drilling automation technology and lower-emissions operations and services, and data analytics. Accordingly, we may have to allocate a higher proportion of our capital expenditures to maintain and improve existing rigs and pressure pumping and other equipment, purchase and construct newer, higher specification drilling rigs and pressure pumping and other equipment to meet the increasingly sophisticated needs of our customers, and develop new and improved technology and data analytics. 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 and directional drilling businesses could have similar effects.

In recent years, we have added drilling rigs to our fleet through new construction, purchased new pressure pumping equipment and acquired a directional drilling services company. We have also improved existing drilling rigs and pressure pumping equipment by adding equipment and technology designed to enhance functionality and performance. Although we take measures to ensure that we use advanced oil and natural gas drilling, pressure pumping and directional drilling technology, changes in technology, improvements in competitors' equipment, increasing customer demands for new and improved technology, such as drilling automation technology and lower-emissions operations and services, and changes relating to the wells to be drilled and completed could make our equipment less competitive.

We continually attempt to develop new technologies for use in our business. In the event that we are successful in developing new technologies for use in our business, there is no guarantee of future demand for those technologies. Customers may be reluctant or unwilling to adopt our new technologies. We may also have difficulty negotiating satisfactory terms for our new technologies, including terms that would enable us to obtain acceptable returns on our investment in the research and development of new technologies.

Development of new technology is critical to maintaining our competitiveness. There can be no assurance that we will be able to successfully develop technology that our customers demand. Some of our competitors have greater financial, technical and personnel resources that may allow them to enjoy technological advantages and develop and implement new technology on a more timely basis or in a more cost-effective manner. 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 equipment and services obsolete, which could reduce our competitiveness and have a material adverse impact on our business, financial condition, cash flows and results of operation.

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 and in developing new technologies. 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 in a period of generally 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 2020, we received approximately 54% from our ten largest customers and approximately 35% from our five largest customers and 8% 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.

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

Periodically, the oilfield services 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 and other equipment and could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our Business Is Subject to Cybersecurity Risks and Threats.

Our operations are increasingly dependent on effective and secure information technologies and services. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow, and include, among other things, storms and natural disasters, terrorist attacks, utility outages, attempts to gain unauthorized access to our data and systems, theft, viruses, malware, design defects, human error, or complications encountered as existing systems are maintained, repaired, replaced, or upgraded. Risks associated with these threats include, among other things:

- theft or misappropriation of funds, including via “phishing” or similar attacks directed at us or our customers;
- loss, corruption, or misappropriation of intellectual property, or other proprietary or confidential information (including customer, supplier, or employee data);
- disruption or impairment of our and our customers’ business operations and safety procedures;
- destruction or damage to our and our customers’ equipment;
- downtime and loss of revenue;
- injury to our reputation;
- negative impacts on our ability to compete;
- loss or damage to our information technology systems, including worksite data delivery systems;

- exposure to litigation; and
- increased costs to prevent, respond to or mitigate cybersecurity events.

In response to the COVID-19 pandemic, many of our office personnel moved to a “remote work” model in March 2020. This model has significantly increased the use of remote networking and online conferencing services that enable employees to work outside of our corporate infrastructure and, in some cases, use their own personal devices. This may expose us to additional cybersecurity risks or related incidents.

Although we utilize various procedures and controls to mitigate our exposure to the risks described above, cybersecurity attacks and other cyber events are evolving and unpredictable. There can be no assurance that the procedures and controls that we implement, or that we cause third party service providers to implement, will be sufficient to protect our systems, information or other property. Moreover, we have no control over the information technology systems of our customers, suppliers, and others with which our systems may connect and communicate. As a result, the occurrence of a cyber incident could go unnoticed for a period of time. We self-insure most of our cybersecurity risks, and any such incident could have a material adverse effect on our business, financial condition, cash flows and results of operations. As cyber incidents continue to evolve, we may be required to incur additional costs to continue to modify or enhance our protective measures or to investigate or remediate the effects of cyber incidents.

Our Commitments Under Supply Agreements Could Exceed Our Requirements, Exposing Us to Risks Including Price, Timing of Delivery and Quality of Equipment and Materials Upon Which Our Business Relies.

We have purchase commitments with certain vendors to supply equipment and materials, including, in the case of our pressure pumping business, proppants. Some of these agreements are take-or-pay agreements with minimum purchase obligations. If demand for our services decreases from current levels, demand for the equipment that we use and the materials that we supply as part of these services will also decrease. In addition, some of our customers may self-source certain materials. If demand for our services and/or materials decreases enough, we could have contractual minimum commitments that exceed the required amount of materials we need to supply to our customers. In this instance, we could be required to purchase materials that we do not have a present need for, pay for materials that we do not take delivery of or pay prices in excess of market prices at the time of purchase.

Growth Through Acquisitions, the Building or Upgrading of Equipment and the Development of Technology Is Not Assured.

We have grown our drilling rig fleet and pressure pumping fleet and expanded our business lines and use of technology in the past through mergers, acquisitions, new construction and technology development. 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 or upgrading equipment or developing new technology. 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, our competitors may continue to build new equipment and develop new technology, including drilling automation technology and lower-emissions operations and services.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions, build or upgrade equipment or develop new technology,
- successfully integrate additional equipment, acquired or developed technology or other assets or businesses,
- effectively manage the growth and increased size of our organization,
- successfully deploy idle, stacked, upgraded or additional equipment and acquired or developed technology,

- maintain the crews necessary to operate additional equipment or the personnel necessary to evaluate, develop and deploy new technology, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition, the building or upgrading equipment or the development of new technology.

Our failure to achieve consolidation savings, to integrate acquired businesses and technology and other assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our business. In addition, we may incur liabilities arising from events prior to any acquisitions, prior to our establishment of adequate compliance oversight or in connection with disputes over acquired or developed technology. While we generally seek to obtain indemnities for liabilities arising from events occurring before such acquisitions, these are limited in amount and duration, may be held to be unenforceable or the seller may not be able to indemnify us.

We may incur substantial indebtedness to finance future acquisitions, build or upgrade equipment or develop new technology, and we also may issue equity, convertible or debt securities in connection with any such acquisitions or building or upgrade 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.

Fuel Conservation Measures Could Reduce Demand for Oil and Natural Gas, Which Would, In Turn, Reduce the Demand for Our Services.

Fuel conservation measures, alternative fuel requirements and increasing consumer demand for alternatives to oil and natural gas could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, cash flows and results of operations. Additionally, the increased competitiveness of alternative energy sources (such as wind, solar geothermal, tidal, and biofuels) could reduce demand for oil and natural gas and therefore for our services, which would lead to a reduction in our revenues.

Legal and Regulatory Risks

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.

Numerous political and regulatory authorities, governmental bodies and officials, and environmental groups devote resources to campaigns aimed at eradicating 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. President Biden and other presidential candidates stated that they would support either increased regulation or a ban on hydraulic fracturing; however, we cannot predict whether hydraulic fracturing regulations will be enacted during the Biden Administration or how stringent they may be. In addition, members of the U.S. Congress and the EPA have reviewed proposals for more stringent regulation of hydraulic fracturing, and various state and local initiatives have been or may be proposed or implemented to further regulate hydraulic fracturing. For example, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and 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, pressure pumping and directional drilling 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. The EPA has not yet finalized this rule. 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, several jurisdictions have taken steps to enact hydraulic fracturing bans, moratoria or increased regulations on hydraulic fracturing practices. 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. In November 2018, voters rejected an initiative that would have materially restricted hydraulic fracturing activity in Colorado; however, the Colorado state legislature subsequently passed a package of oil and gas development regulations in April 2019. In November 2019, the California governor’s office imposed new regulations on hydraulic fracturing, including a moratorium on all new hydraulic fracturing permits pending review by a panel of scientists. Recently, bills have been introduced in the New Mexico Senate to place a moratorium on hydraulic fracturing. Further, at various times during his campaign, President Biden proposed a ban of new leases for production of minerals on federal lands, and the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee. Subsequently, President Biden issued an executive order imposing a moratorium on new oil and gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices.

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 restrict our ability, or 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. Additionally, the adoption of significant restrictions or a prohibition on hydraulic fracturing by a state, region or locality could result in a surplus of oilfield equipment in other states, regions or localities where hydraulic fracturing remains allowed.

Our and Our Customers' Operations are Subject to a Number of Risks Arising Out of the Threat of Climate Change That Could Result in Increased Operating and Capital Costs, Limit the Areas in Which Oil and Natural Gas Production May Occur and Reduce Demand for Our Services.

The physical and regulatory effects of climate change could have a negative impact on our operations, our customers' operations and the overall demand for our customers' products and, accordingly, our services. There is an 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. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. 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. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain oil and natural gas system sources, implement CAA emission standards directing the reduction of methane emissions from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States.

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. In November 2020, the United States' previously-announced withdrawal from the Paris Agreement became effective. On January 20, 2021 President Biden announced that the United States would be reentering the Paris Agreement. This reentry will become effective on February 19, 2021. Several states and geographic regions in the United States have also adopted legislation and regulations to reduce emissions of GHGs, including cap and trade regimes and commitments to contribute to meeting the goals of the Paris Agreement.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States. Critical declarations made by one or more presidential candidates included proposals to ban hydraulic fracturing of oil and natural gas wells and bans on new leases for production of minerals on federal lands. President Biden and the Democratic Party, which now controls Congress, have identified climate change as a priority, and it is likely that new executive orders, regulatory action, and/or legislation targeting greenhouse gas emissions, or prohibiting or restricting oil and gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. For example, the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee, and President Biden issued an executive order imposing a moratorium on new oil and gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. President Biden's order also established climate change as a primary foreign policy and national security consideration, affirms that achieving net-zero greenhouse gas emissions by or before midcentury is a critical priority, affirms the Biden Administration's desire to establish the United States as a leader in addressing climate change, generally further integrates climate change and environmental justice considerations into government agencies' decision-making, and eliminates fossil fuel subsidies, among other measures. Other actions impacting oil and natural gas production activities that could be pursued by the Biden administration may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquified natural gas export facilities.

It is not possible at this time to predict the timing and effects of climate change or to predict the timing or effect of rejoining the Paris Agreement or whether additional climate-related legislation, regulations or other measures will be adopted at the local, state, regional, national and international levels. However, continued efforts by governments and non-governmental organizations to reduce GHG emissions appear likely, and additional legislation, regulation or other measures that control or limit GHG emissions or otherwise seek to address climate change could adversely affect our business. 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 increase compliance costs, add operating restrictions, or reduce demand for our customers' products and, accordingly, our services.

There are also increasing financial risks for oil and natural gas producers, as stockholders and bondholders currently invested in oil and natural gas companies concerned about the potential effects of climate change and other sustainability-related issues may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Additionally, the lending and investment practices of institutional lenders and investors have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, not to provide funding for oil and natural gas producers. Limitation of investments in and financings for oil and natural gas could result in the restriction, delay, or cancellation of drilling and completion programs or development of production activities. An increasing number of our customers consider sustainability factors in awarding work. If we are unable to successfully continue our sustainability enhancement efforts, we may lose customers, our stock price may be negatively impacted, our reputation may be negatively affected, and it may be more difficult for us to effectively compete.

Increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors.

These political, litigation, and financial risks may result in our customers restricting or cancelling production activities, incurring liability for infrastructure damage as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our products and services. One or more of these developments could have a material adverse effect on our business, financial condition, cash flows and results of operations. Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our operations.

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 or judgments,
- 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 places that 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, a manufacturer and servicer of equipment and automation to the energy, marine and mining industries and a provider of directional drilling and other services, we may be deemed to be a responsible party under these laws and regulations.

Technology Disputes Could Negatively Impact Our Operations or Increase Our Costs.

Our services and products use proprietary technology and equipment, which can involve potential infringement of a third party’s rights, or a third party’s infringement of our rights, including patent rights. The majority of the intellectual property rights relating to our drilling rigs, pressure pumping equipment and directional drilling services are owned by us or certain of our supplying vendors. However, in the event that we or one of our customers or supplying vendors becomes involved in a dispute over infringement of intellectual property rights relating to equipment or technology owned or used by us, services performed by us or products provided by us, we may lose access to important equipment or technology or our ability to provide services or products, or we could be required to cease use of some equipment or technology or forced to modify our equipment, technology, services or products. We could also be required to pay license fees or royalties for the use of equipment or technology or provision of services or products. In addition, we may lose a competitive advantage in the event we are unsuccessful in enforcing our rights against third parties. Technology disputes involving us or our customers or supplying vendors 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 Electrical Controls, 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 electrical controls, to customers involved in oil and gas exploration, development and production and in the marine and mining industries. Because of applications that 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 harm to our reputation, contractual and warranty-related liability, damage to the equipment, damage to the property of customers and others, personal injury and environmental contamination, leading to claims against us.

Legal Proceedings and Governmental Investigations Could Have a Negative Impact on Our Business, Financial Condition and Results of Operations.

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, we may be subject to an increased risk of our customers, vendors, current and former employees and others initiating legal proceedings against us. Additionally, actions or decisions we have taken or may take as a consequence of the COVID-19 pandemic may result in investigations, litigation or legal claims 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. Please see “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.”

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

We sell products, including electrical controls, for use in numerous oil and gas producing regions outside of North America, and through our Superior QC business, we occasionally provide remote data analytics and other services to customers to support their operations outside of the United States. We also continue to evaluate opportunities from time to time to provide our other services outside of the United States. 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 our services could be provided or where our consumers for 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. In addition, investors could negatively view potential violations, inquiries or allegations of misconduct under the FCPA or similar laws, which could adversely affect our reputation and the market for our shares. 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.

Many countries, including the United States, control the import and export of certain goods, services and technology and impose related import and export recordkeeping and reporting obligations. Governments also may impose economic sanctions against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities. In particular, U.S. sanctions are targeted against certain countries that are heavily involved in the oil and gas industry. The laws and regulations concerning import and export activity, recordkeeping and reporting, including customs, export controls and economic sanctions, are complex and constantly changing. Any failure to comply with applicable legal or regulatory requirements governing international trade could also result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of shipments and loss of import and export privileges.

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.

Financial Risks

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

We have borrowings outstanding under our senior notes and our term loan agreement and, from time to time, our revolving credit facility. Our ability to meet our interest and principal payment obligations depends in large part on cash flows from our subsidiaries. If our subsidiaries do not generate sufficient cash flows, 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 term loan facility under our Term Loan Agreement. Interest is paid on the outstanding principal amount of borrowings under the Term Loan Agreement at a floating rate based on, at our election, LIBOR or a base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans and base rate loans was 1.375% and 0.375%, respectively. As of December 31, 2020, we had $50 million in borrowings outstanding under the Term Loan Agreement.

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. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans was 1.75% and the applicable margin on base rate loans was 0.75%. As of December 31, 2020, we had no borrowings outstanding under our revolving credit facility.

Finally, 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, 2020, 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 at floating rates under these agreements or under future agreements.

A Downgrade in Our Credit Rating Could Negatively Impact Our Cost of and Ability to Access Capital.

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by major U.S. credit rating agencies. Factors that may impact our credit ratings include debt levels, liquidity, asset quality, cost structure, commodity pricing levels, industry conditions and other considerations, including the impact of the COVID-19 pandemic. A ratings downgrade could adversely impact our ability in the future to access debt markets, increase the cost of future debt, and potentially require us to post letters of credit for certain obligations.

We May Not Be Able to Generate Sufficient Cash to Service All of Our Debt and We May Be Forced to Take Other Actions to Satisfy Our Obligations Under Our Debt, which May Not Be Successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure you that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

In addition, if our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our debt. We cannot assure you that we would be able to take any of these actions, that these actions would be successful and would permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements. In the absence of such cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. However, our debt agreements contain restrictions on our ability to dispose of assets. We may not be able to consummate those dispositions, and any proceeds may not be adequate to meet any debt service obligations then due.

Risks Related to Our Common Stock and Corporate Structure

The Market Price of Our Common Stock May Be Highly Volatile, and Investors May Not Be Able to Resell Shares at or Above the Price Paid.

The trading price of our common stock may be volatile. Securities markets worldwide experience significant price and volume fluctuations. This market volatility, as well as other general economic, market or political conditions, could reduce the market price of our common stock in spite of our operating and/or financial performance. The following factors, in addition to other factors described in this “Risk Factors” section and elsewhere in this Report, may have a significant impact on the market price of our common stock:

- investor perception of us and the industry and markets in which we operate;
- general financial, domestic, international, economic, and market conditions, including overall fluctuations in the U.S. equity markets;
- increased focus by the investment community on sustainability practices at our company and in the oil and natural gas industry generally;
- changes in customer needs, expectations or trends and our ability to maintain relationships with key customers;
- our ability to implement our business strategy;
- changes in our capital structure, including the issuance of additional debt;
- public announcements (including the timing of these announcements) regarding our business, financial performance and prospects or new services or products, service or product enhancements, technological advances or strategic actions, such as acquisitions or divestitures, restructurings or significant contracts, by our competitors or us;
- trading activity in our stock, including portfolio transactions in our stock by us, our executive officers and directors, and significant stockholders or trading activity that results from the ordinary course rebalancing of stock indices in which we may be included;
- short-interest in our common stock, which could be significant from time to time;
- our inclusion in, or removal from, any stock indices;
- changes in earnings estimates or buy/sell recommendations by securities analysts;
- whether or not we meet earnings estimates of securities analysts who follow us; and
- regulatory or legal developments in the United States and foreign countries where we operate.

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. In addition, we have adopted a stockholder rights agreement that could make it more difficult for a third-party to acquire our common stock without the approval of our Board of Directors.

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 — Our drilling services are supported by multiple offices and yard facilities located throughout our areas of operations, including Texas, Oklahoma, Colorado, North Dakota, Wyoming, Pennsylvania, and Ohio.

Pressure Pumping — Our pressure pumping services are supported by multiple offices and yard facilities located in Texas and Pennsylvania.

Directional Drilling — Our directional drilling services are supported by multiple offices and yard facilities located throughout our areas of operations, including Texas, North Dakota, and Ohio.

Our oilfield rental operations are supported by offices and yard facilities located in Texas, Oklahoma and Ohio. Our servicing of equipment for drilling contractors is supported by offices and yard facilities located in Texas. Our electrical controls and automation operation is supported by an office and yard facility in 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 6 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 our 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, cash flows and results of operations.

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 SmallCap 600 Index and several other market indices.

(b) Holders

As of February 4, 2021, there were approximately 900 holders of record of our common stock.

(c) Dividends

On February 3, 2021, 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 18, 2021 to holders of record as of March 4, 2021. 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.

(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, 2020.

Period Covered	Total Number of Shares Purchased (1)	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) (2)
October 2020	16,582	$2.84	—	$130,000
November 2020	—	$ —	—	$130,000
December 2020	537	$5.43	—	$130,000
Total	17,119		—	

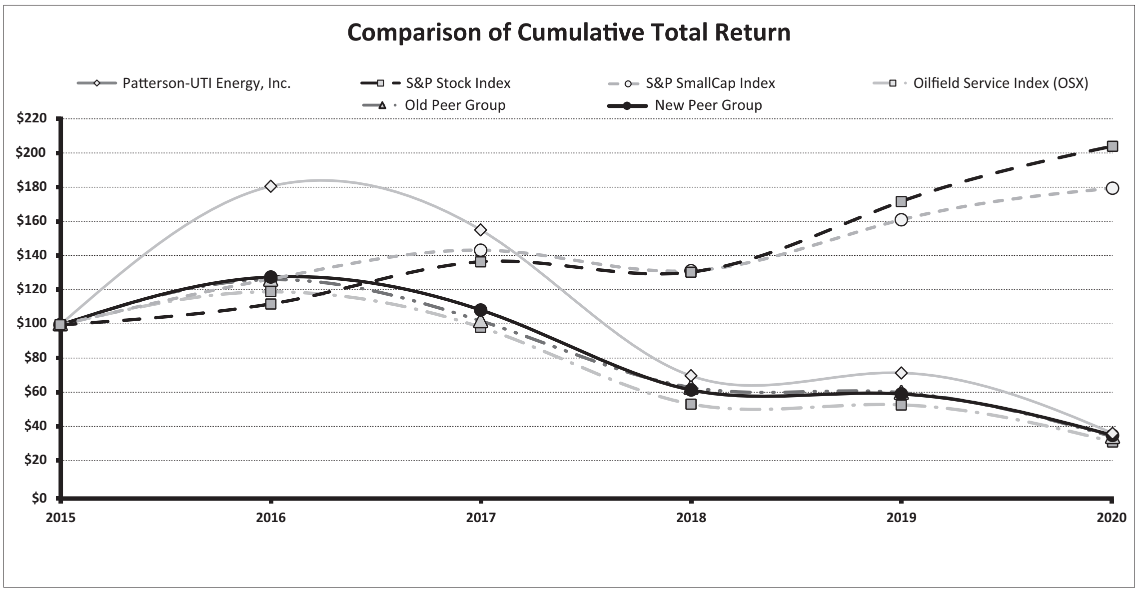
(1) We withheld 17,119 shares in the fourth quarter with respect to employees' tax withholding obligations upon the vesting of restricted stock units. These shares were acquired at fair market value pursuant to the terms of the Patterson-UTI Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan, as amended, and not pursuant to the stock buyback program.

(2) 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. On July 26, 2018, we announced that our Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 7, 2019, we announced that our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 25, 2019, we announced that our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. All purchases executed to date have been through open market transactions. Purchases under the program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. Shares of stock purchased under the buyback program are held as treasury shares. There is no expiration date associated with the buyback program.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2015 through December 31, 2020, with the cumulative total return of the S & P 500 Index, the S & P SmallCap 600 Index, the Oilfield Service Index and a peer group determined by us. We changed our peer group in 2020 to align with the peer group used by the compensation committee of our Board of Directors. Our new peer group consists of ChampionX Corporation, Archrock, Inc., Cimarex Energy Co., Diamond Offshore Drilling Inc., EQT Corporation, Helmerich & Payne, Inc., Liberty Oilfield Services Inc., Nabors Industries, Ltd., National Oilwell Varco, Inc., NexTier Oilfield Solutions Inc., Noble Corporation plc., Oceaneering International, Oil States International Inc., PDC Energy, Inc., Precision Drilling Corporation, Range Resources, TechnipFMC plc, Transocean Ltd., Valaris plc, and WPX Energy, Inc. Our old peer group consisted of Basic Energy Services, Inc., Diamond Offshore Drilling, Inc., Forum Energy Technologies, Inc., Halliburton Company, Helmerich & Payne, Inc., Nabors Industries, Ltd., National Oilwell Varco, Inc., Noble Corporation plc., Oceaneering International, Oil States International, Inc., Precision Drilling Corporation, Superior Energy Services, Inc., TechnipFMC plc., Transocean Ltd., Unit Corp., Valaris plc and Weatherford International plc.

The graph assumes investment of $100 on December 31, 2015 and reinvestment of all dividends.



Company/Index	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)	2020 ($)
	Fiscal Year Ended December 31,					
Patterson-UTI Energy, Inc.	100.00	180.01	154.44	70.07	72.23	36.98
S&P 500 Stock Index	100.00	111.96	136.40	130.42	171.49	203.04
S&P SmallCap 600 Index	100.00	126.56	143.30	131.15	161.03	179.20
Oilfield Service Index	100.00	118.98	98.51	53.97	53.67	31.09
Old Peer Group Index	100.00	127.68	108.49	62.22	59.96	35.06
New Peer Group Index	100.00	126.23	102.15	63.67	60.68	34.89

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, 2020, 2019, 2018, 2017 and 2016, and for each of the five years in the period ended December 31, 2020, 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. We completed several mergers and acquisitions during the five-year period ended December 31, 2020. As such, the table below includes the results of operations of Current Power since October 25, 2018, the results of operations of Superior QC since February 20, 2018, the results of operations of MS Directional since October 11, 2017 and the results of operations of Seventy Seven Energy since April 20, 2017. See Note 2 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report for financial information pertaining to these transactions.

On January 1, 2018, we adopted the new revenue guidance under Topic 606, Revenue from Contracts with Customers, using the modified retrospective method. Additionally, on January 1, 2019, we adopted the new lease guidance under Topic 842, Leases, using the modified retrospective approach. See Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report for information pertaining to the adoption of these standards and comparability between periods.

	2020	2019	2018	2017	2016
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$ 669,126	$1,308,350	$1,430,492	$1,040,033	$ 543,663
Pressure pumping	336,111	868,694	1,573,396	1,200,311	354,070
Directional drilling	73,356	188,786	209,275	45,580	—
Other	45,656	104,855	113,834	70,760	18,133
Total	1,124,249	2,470,685	3,326,997	2,356,684	915,866
Operating costs and expenses:					
Contract drilling	380,822	785,355	885,704	667,105	305,804
Pressure pumping	310,261	724,788	1,263,850	966,835	334,588
Directional drilling	69,050	178,645	175,829	32,172	—
Other	41,790	84,909	77,104	51,428	8,384
Depreciation, depletion, amortization and impairment	670,910	1,003,873	916,318	783,341	668,434
Impairment of goodwill	395,060	17,800	211,129	—	—
Selling, general and administrative	97,611	133,513	134,071	105,847	69,205
Credit loss expense	5,606	5,683	—	—	—
Merger and integration expenses	—	—	2,738	74,451	—
Restructuring expenses	38,338	—	—	—	—
Other operating expenses (income), net	7,059	(2,305)	(17,569)	(31,957)	(14,323)
Total	2,016,507	2,932,261	3,649,174	2,649,222	1,372,092
Operating loss	(892,258)	(461,576)	(322,177)	(292,538)	(456,226)
Other expense	(38,760)	(68,802)	(45,231)	(35,263)	(39,970)
Loss before income taxes	(931,018)	(530,378)	(367,408)	(327,801)	(496,196)
Income tax benefit	(127,326)	(104,675)	(45,987)	(333,711)	(177,562)
Net income (loss)	$ (803,692)	$ (425,703)	$ (321,421)	$ 5,910	$ (318,634)
Net income (loss) per common share:					
Basic	$ (4.27)	$ (2.10)	$ (1.47)	$ 0.03	$ (2.18)
Diluted	$ (4.27)	$ (2.10)	$ (1.47)	$ 0.03	$ (2.18)
Cash dividends per common share	$ 0.10	$ 0.16	$ 0.14	$ 0.08	$ 0.16
Weighted average number of common shares outstanding:					
Basic	188,013	203,039	218,643	198,447	146,178
Diluted	188,013	203,039	218,643	199,882	146,178
Balance Sheet Data:					
Total assets	$3,299,069	$4,439,615	$5,469,866	$5,758,856	$3,772,291
Long-term lease liability	19,118	26,644	—	—	—
Borrowings under line of credit	—	—	—	268,000	—
Other long-term debt	901,484	966,540	1,119,205	598,783	598,437
Stockholders' equity	2,016,059	2,833,620	3,505,423	3,982,493	2,248,724
Working capital	204,234	231,213	423,881	200,605	(17,933)

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

Management Overview and Recent Developments in Market Conditions — We are a Houston, Texas-based oilfield services company that primarily owns and operates one of the largest fleets of land-based drilling rigs in the United States and a large fleet of pressure pumping equipment.

Our contract drilling business operates in the continental United States and, from time to time, we pursue contract drilling opportunities in other select markets. Our pressure pumping business operates primarily in Texas and the Appalachian region. We also provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States, and we provide services that improve the statistical accuracy of horizontal wellbore placement. We have other operations through which we provide oilfield rental tools in select markets in the United States. We also service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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.

Reduced demand for crude oil and refined products related to the COVID-19 pandemic, combined with production increases from OPEC+, led to a significant reduction in crude oil prices and demand for drilling and completion services in the United States.

Oil prices remain extremely volatile, as the closing price of oil (WTI-Cushing) reached a first quarter 2020 high of $63.27 per barrel on January 6, 2020, declined to negative $36.98 per barrel on April 20, 2020, and closed at $53.55 per barrel on February 1, 2021. In response to the rapid decline in commodity prices, E&P companies acted swiftly to reduce drilling and completion activity starting late in the first quarter of 2020. While oil prices recovered from the lows experienced in the first half of 2020, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our pressure pumping horsepower remains stacked. Oil prices averaged $42.45 per barrel in the fourth quarter of 2020.

Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2018, 2019 and 2020 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2018:				
Average oil price per Bbl (1)	$62.88	$68.04	$69.76	$59.08
Average rigs operating per day — U.S. (2)	166	175	177	182
2019:				
Average oil price per Bbl (1)	$54.83	$59.78	$56.37	$56.94
Average rigs operating per day — U.S. (2)	174	157	142	122
2020:				
Average oil price per Bbl (1)	$45.76	$27.81	$40.89	$42.45
Average rigs operating per day — U.S. (2)	123	82	60	62

(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.

Our active rig count has declined since the fourth quarter of 2018. Our average active rig count for the fourth quarter of 2020 was 62 rigs. This was an increase from our average active rig count for the third quarter of 2020 of 60 rigs. Our U.S. active rig count at December 31, 2020 of 65 rigs was less than the rig count of 121 rigs at December 31, 2019, due to the significantly reduced demand for drilling services in the United States. Term contracts help support our operating rig count. Based on contracts currently in place, we expect an average of 42 rigs operating under term contracts during the first quarter of 2021 and an average of 34 rigs operating under term contracts throughout 2021.

Due to the downturn in completions activity since March, we averaged seven active pressure pumping spreads during the fourth quarter, up from an average of five active spreads during the third quarter, but down from an average of 12 active spreads during the fourth quarter of 2019. We expect to average seven active pressure pumping spreads during the first quarter of 2021. The pressure pumping market remains oversupplied.

Recent Developments in Financial Matters — During the fourth quarter of 2020, we elected to repurchase portions of our 2028 Notes and 2029 Notes (as defined below) in the open market. The principal amounts retired through these transactions totaled $15.5 million related to our 2028 Notes and $0.8 million related to our 2029 Notes, plus accrued interest. We recorded corresponding gains on the extinguishment of these amounts totaling $3.4 million and $0.2 million, respectively, net of the proportional write-off of associated deferred financing costs and original issuance discounts. These gains are included in “Interest expense, net of amount capitalized” in the consolidated statements of operations.

On December 24, 2020, we elected to repay $50 million of the borrowings under our Term Loan Agreement (as defined below). As of December 31, 2020, we had $50 million in borrowings remaining under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. The maturity date of the Term Loan Agreement is June 10, 2022.

On March 27, 2020, we entered into Amendment No. 2 to Amended and Restated Credit Agreement (“Amendment No. 2”) to, among other things, extend the maturity date for $550 million of revolving credit commitments of certain lenders under the Credit Agreement (as defined below) from March 27, 2024 to March 27, 2025. We have the option, subject to certain conditions, to exercise an additional one-year extension of the maturity date.

Please see “– Liquidity and Capital Resources” for additional detail regarding our 2028 Notes, 2029 Notes, Term Loan Agreement and Credit Agreement.

During the second quarter of 2020, we implemented a restructuring plan to improve operating margins, achieve operational efficiencies and reduce indirect support costs. The restructuring included workforce reductions, changes to management structure and facility consolidations and closures. We recorded $38.3 million of charges associated with this plan in the second quarter of 2020. In conjunction with our restructuring, we closed our Canadian drilling operations. We recorded an impairment of $8.3 million associated with that closure. We completed the restructuring plan during the third quarter of 2020 and did not incur additional expenses related to the plan.

The following table presents restructuring expenses by reportable segment for the year ended December 31, 2020 (in thousands):

	Contract Drilling	Pressure Pumping	Directional Drilling	Other Operations	Corporate	Total
Severance costs	$1,821	$ 3,460	$ 503	$ 501	$ 215	$ 6,500
Contract termination costs	—	20,373	—	—	—	20,373
Other exit costs	523	194	827	—	—	1,544
Right-of-use asset abandonments	86	7,304	1,845	—	686	9,921
Total	$2,430	$31,331	$3,175	$ 501	$ 901	$38,338

We estimate that the restructuring plan implemented in 2020 will result in annual cost savings of approximately $94 million. Of these estimated annual cost savings, approximately $14 million, $43 million, $7 million and $8 million are attributable to operating expense savings for contract drilling, pressure pumping, directional drilling and other operations, respectively. Annual selling, general and administrative cost savings are estimated to be approximately $22 million.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and upon our customers' ability to access capital to fund their operating and capital expenditures. During periods of improved oil and natural gas 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 oil and natural gas prices are relatively low or when our customers have a reduced ability to access capital, the demand for our services generally weakens, and we experience downward pressure on pricing for our services. We may also be impacted by delayed customer payments and payment defaults associated with customer liquidity issues and bankruptcies.

The North American oil and natural gas services industry is cyclical and at times experiences downturns in demand. During these periods, there has been substantially more oil and natural gas service equipment available than necessary to meet demand. As a result, oil and natural gas service contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods. Currently, there is an excess supply of drilling rigs, pressure pumping equipment and directional drilling equipment. We cannot predict either the future level of demand for our oil and natural gas services or future conditions in the oil and natural gas service businesses.

In addition to the dependence on oil and natural gas prices and demand for our services, we are highly impacted by operational risks, competition, labor issues, weather, the availability, from time to time, of products used in our pressure pumping business, supplier delays and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations, including as a result of the COVID-19 pandemic. See "Risk Factors" in Item 1A of this Report.

For the three years ended December 31, 2020, our operating revenues consisted of the following (dollars in thousands):

	2020		2019		2018	
Contract drilling	$ 669,126	59.5%	$1,308,350	53.0%	$1,430,492	43.0%
Pressure pumping	336,111	29.9%	868,694	35.2%	1,573,396	47.3%
Directional drilling	73,356	6.5%	188,786	7.6%	209,275	6.3%
Other	45,656	4.1%	104,855	4.2%	113,834	3.4%
	$1,124,249	100.0%	$2,470,685	100.0%	$3,326,997	100.0%

Contract Drilling

Contract drilling revenues accounted for 59.5% of our consolidated 2020 revenues and decreased 48.9% from 2019.

We have addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by improving the capabilities of our drilling fleet during the last several years. The U.S. land rig industry refers 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 at least a 750,000-pound hookload, a 7,500-psi circulating system, and is pad-capable. As of December 31, 2020, our rig fleet included 198 APEX® rigs, of which 150 were super-spec rigs.

We maintain a backlog of commitments for contract drilling services under term contracts, which we define as contracts with a duration of six months or more. Our contract drilling backlog as of December 31, 2020 and 2019 was approximately $301 million and $605 million, respectively. Approximately 21% of the total contract drilling backlog at December 31, 2020 is reasonably expected to remain after 2021. 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 fees for other services such as for mobilization, other than initial 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. For contracts that contain variable dayrate pricing, our backlog calculation uses the dayrate in effect for periods where the dayrate is fixed, and, for periods that remain subject to variable pricing, uses the commodity price in effect at December 31, 2020. 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 on which we have received notice for the rig to be placed on standby, our backlog calculation uses the standby rate for the period over which we expect to receive the standby rate. For contracts on which we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period over which we expect to receive the lower rate. See "Item 1A. Risk Factors – Our Current Backlog of Contract Drilling Revenue May Decline and May Not Ultimately Be Realized, as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment."

Pressure Pumping

Pressure pumping revenues accounted for 29.9% of our consolidated 2020 revenues and decreased 61.3% from 2019. As of December 31, 2020, we had approximately 1.4 million horsepower in our pressure pumping fleet. The pressure pumping market remains oversupplied. In response to oversupplied market conditions, we implemented changes during the second quarter of 2020 that are intended to further streamline our operations, improve our efficiencies, and reduce our overall cost structure, while maintaining our customer service levels.

Directional Drilling

Directional drilling revenues accounted for 6.5% of our consolidated 2020 revenues and decreased 61.1% from 2019. We provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States. Our directional drilling services include directional drilling, measurement-while-drilling and supply and rental of downhole performance motors and wireline steering tools. We also provide services that improve the statistical accuracy of horizontal wellbore placement.

Other Operations

Other operations revenues accounted for 4.1% of our consolidated 2020 revenues and decreased 56.5% from 2019. Our oilfield rentals business, with a fleet of premium oilfield rental tools, provides the largest revenue contribution to our other operations and provides specialized services for land-based oil and natural gas drilling, completion and workover activities. Other operations also includes the results of our electrical controls and automation business, the results of our drilling equipment service business, and the results of our ownership, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Capital Expenditures

Cash capital expenditures for 2020 totaled $145 million. This was a reduction from the $348 million of cash capital expenditures for 2019, due largely to lower activity levels. Based on our current outlook for activity, we expect our capital expenditures for 2021 to be approximately $135 million.

For the three years ended December 31, 2020, our operating losses consisted of the following (dollars in thousands):

	2020		2019		2018	
Contract drilling	$(543,438)	60.9%	$(151,329)	32.8%	$ (33,115)	10.3%
Pressure pumping	(166,666)	18.7%	(102,701)	22.3%	(77,328)	24.0%
Directional drilling	(40,612)	4.6%	(52,724)	11.4%	(117,497)	36.5%
Other	(41,685)	4.7%	(54,725)	11.9%	(18,221)	5.7%
Corporate	(99,857)	11.1%	(100,097)	21.6%	(76,016)	23.5%
	$(892,258)	100.0%	$(461,576)	100.0%	$(322,177)	100.0%

Lower demand for our contract drilling and pressure pumping services, an impairment of goodwill and an implementation of a restructuring plan in 2020 contributed to a consolidated net loss of $804 million for 2020, compared to a consolidated net loss of $426 million for 2019 and consolidated net loss of $321 million for 2018.

Results of Operations

Comparison of the years ended December 31, 2020 and 2019

The following tables summarize results of operations by business segment for the years ended December 31, 2020 and 2019:

	Year Ended December 31,		
Contract Drilling	**2020**	**2019**	**% Change**
	(Dollars in thousands)		
Revenues	$ 669,126	$1,308,350	(48.9)%
Direct operating costs	380,822	785,355	(51.5)%
Margin (1)	288,304	522,995	(44.9)%
Restructuring expenses	2,430	—	NA
Other operating expenses (income), net	(4,185)	—	NA
Selling, general and administrative	4,666	6,317	(26.1)%
Depreciation, amortization and impairment	433,771	668,007	(35.1)%
Impairment of goodwill	395,060	—	NA
Operating loss	$(543,438)	$ (151,329)	259.1%
Operating days (2)	29,904	54,544	(45.2)%
Average revenue per operating day	$ 22.38	$ 23.99	(6.7)%
Average direct operating costs per operating day	$ 12.73	$ 14.40	(11.6)%
Average margin per operating day (1)	$ 9.64	$ 9.59	0.5%
Average rigs operating	81.7	$ 149.4	(45.3)%
Capital expenditures	$ 105,037	$ 194,416	(46.0)%

(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 operating day is defined as margin divided by operating days.

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

Reduced demand for crude oil and refined products related to the COVID-19 pandemic, combined with production increases from OPEC+, led to a significant reduction in crude oil prices and demand for contract drilling services.

Generally, the revenues in our contract drilling segment are most impacted by two primary factors: our average number of rigs operating and our average revenue per operating day. During 2020, our average number of rigs operating was 82, compared to 149 in 2019. Our average rig revenue per operating day was $22,380 in 2020, compared to $23,990 in 2019. Our average revenue per operating day is largely dependent on the pricing terms of our rig contracts.

Revenues and direct operating costs decreased primarily due to a decrease in operating days. Average direct operating costs per operating day decreased due to cost reduction efforts and a higher percentage of rigs on standby during 2020. Rigs on standby have very little associated cost. Average margin per operating day in 2020 included benefits from lump sum early termination revenue and a credit to operating costs for sales and use taxes.

Restructuring expenses were recognized in the second quarter of 2020 and primarily related to severance costs. See Note 20 of Notes to Consolidated Financial Statements for additional information.

The increase in other operating expenses (income), net is primarily due to an insurance reimbursement for damaged drilling equipment.

Depreciation, amortization and impairment expense decreased primarily due to a $173 million write-down in 2019 related to the retirement of 36 legacy non-APEX® drilling rigs. In addition to the charge in 2019, no depreciation expense was recorded for this equipment in 2020. Additionally, in the second quarter of 2020 we recorded a $8.3 million write-down related to the closing of our Canadian drilling operations.

All of the goodwill associated with our contract drilling reporting unit was impaired in 2020. See Note 7 of Notes to Consolidated Financial Statements for additional information.

The decrease in capital expenditures was primarily due to higher maintenance capital expenditures in 2019 when activity levels were higher and reduced capital expenditures in 2020 due to lower activity.

	Year Ended December 31,		
Pressure Pumping	**2020**	**2019**	**% Change**
	(Dollars in thousands)		
Revenues	$ 336,111	$ 868,694	(61.3)%
Direct operating costs	310,261	724,788	(57.2)%
Margin [1]	25,850	143,906	(82.0)%
Restructuring expenses	31,331	—	NA
Selling, general and administrative	8,555	12,655	(32.4)%
Depreciation, amortization and impairment	152,630	233,952	(34.8)%
Operating loss	$(166,666)	$(102,701)	62.3%
Fracturing jobs	265	505	(47.5)%
Other jobs	736	844	(12.8)%
Total jobs	1,001	1,349	(25.8)%
Average revenue per fracturing job	$1,188.46	$1,673.81	(29.0)%
Average revenue per other job	$ 28.76	$ 27.75	3.7%
Average revenue per total job	$ 335.78	$ 643.95	(47.9)%
Average direct operating costs per total job	$ 309.95	$ 537.28	(42.3)%
Average margin per total job [1]	$ 25.82	$ 106.68	(75.8)%
Margin as a percentage of revenues [1]	7.7%	16.6%	(53.6)%
Capital expenditures	$ 21,678	$ 105,803	(79.5)%

(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.

Reduced demand for crude oil and refined products related to the COVID-19 pandemic, combined with production increases from OPEC+, led to a significant reduction in crude oil prices and demand for pressure pumping services.

Generally, the revenues in our pressure pumping segment are most impacted by our number of fracturing jobs and the size (including whether or not we provide proppant and other materials) of those jobs, which is reflected in our average revenue per fracturing job. Direct operating costs are also most impacted by these same factors. Our average revenue per fracturing job is largely dependent on the pricing terms of our pressure pumping contracts. We completed 265 fracturing jobs during 2020 compared to 505 fracturing jobs in 2019. Our average revenue per fracturing job was $1.188 million in 2020 compared to $1.674 million in 2019.

Revenues and direct operating costs decreased in 2020 primarily due to a decline in the number of fracturing jobs. Average revenue and direct operating costs per job were impacted by lower demand and a change in the composition of our jobs.

Restructuring expenses were recognized in the second quarter of 2020. These restructuring expenses included $7.3 million related to right-of-use asset abandonments, $3.5 million of severance costs and $20.4 million of contract termination costs. See Note 20 of Notes to Consolidated Financial Statements for additional information.

Selling, general and administrative expenses decreased primarily as a result of cost reduction efforts.

Depreciation, amortization and impairment expense decreased due to the significant decline in capital expenditures and a $20.5 million write-down of pressure pumping equipment in 2019, which resulted in no depreciation expense being recorded for this equipment in 2020.

The decrease in capital expenditures was primarily due to higher maintenance capital expenditures in 2019 when activity levels were higher and reduced capital expenditures in 2020 due to lower activity.

	Year Ended December 31,		
Directional Drilling	**2020**	**2019**	**% Change**
	(Dollars in thousands)		
Revenues	$ 73,356	$188,786	(61.1)%
Direct operating costs	69,050	178,645	(61.3)%
Margin [1]	4,306	10,141	(57.5)%
Restructuring expenses	3,175	—	NA
Selling, general and administrative	5,239	10,642	(50.8)%
Depreciation and amortization	36,504	52,223	(30.1)%
Operating loss	$(40,612)	$ (52,724)	(23.0)%
Capital expenditures	$ 4,681	$ 15,549	(69.9)%

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

Reduced demand for crude oil and refined products related to the COVID-19 pandemic, combined with production increases from OPEC+, led to a significant reduction in crude oil prices and demand for directional drilling services.

Directional drilling revenue decreased by $115 million from 2019 primarily due to decreased job activity.

Directional drilling direct operating costs decreased by $110 million primarily due to lower direct costs from decreased job activity and cost reduction efforts.

Restructuring expenses were recognized in the second quarter of 2020 and were primarily attributable to severance and right-of-use asset abandonments. See Note 20 of Notes to Consolidated Financial Statements for additional information.

Selling, general and administrative expenses decreased primarily as a result of cost reduction efforts.

The decrease in capital expenditures was primarily due to higher maintenance capital expenditures in 2019 when activity levels were higher and reduced capital expenditures in 2020 due to lower activity.

Other Operations	Year Ended December 31, 2020	2019	% Change
	(Dollars in thousands)		
Revenues	$ 45,656	$104,855	(56.5)%
Direct operating costs	41,790	84,909	(50.8)%
Margin [1]	3,866	19,946	(80.6)%
Restructuring expenses	501	—	NA
Selling, general and administrative	3,539	14,068	(74.8)%
Depreciation, depletion, amortization and impairment	41,511	42,803	(3.0)%
Impairment of goodwill	—	17,800	NA
Operating loss	$(41,685)	$ (54,725)	(23.8)%
Capital expenditures	$ 12,378	$ 27,132	(54.4)%

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

Reduced demand for crude oil and refined products related to the COVID-19 pandemic, combined with production increases from OPEC+, led to a significant reduction in crude oil prices and demand for oilfield rental and other services.

Other operations revenue decreased by $59.2 million from 2019 primarily due to a decrease in the volume of services provided by our oilfield rentals business and a decline in the average price per barrel of crude oil received by our oil and natural gas assets.

Other operations direct operating costs decreased by $43.1 million from 2019 primarily due to a decrease in the volume of services provided by our oilfield rentals business. Additionally, a portion of the decrease is attributed to the decision to transition away from our engineering and manufacturing efforts in Calgary during 2019. Charges associated with this decision totaled $12.4 million for direct operating costs in 2019, which were primarily comprised of inventory write-offs.

Restructuring expenses were recognized in 2020 and related to severance costs. See Note 20 of Notes to Consolidated Financial Statements for additional information.

Selling, general and administrative expense decreased primarily as a result of cost reduction efforts in addition to the transition away from our engineering and manufacturing efforts in Calgary during 2019. Charges associated with that decision totaled $2.2 million in 2019.

Depreciation, depletion, amortization and impairment remained relatively consistent with the comparable prior year period. We recognized a $11.2 million impairment related to certain of our oil and natural gas assets recorded in 2020, whereas $2.2 million of oil and natural gas property impairments were recorded in 2019. However, the increased oil and natural gas property impairments were partially offset by decreased 2020 depletion of our oil and natural gas assets primarily due to a decrease in production as well as certain equipment reaching the end of its depreciable life in our oilfield rentals business.

There were no impairments of goodwill in 2020 as all of the goodwill associated with our oilfield rentals and electrical controls and automation businesses was impaired in 2019.

The decrease in capital expenditures was primarily due to higher maintenance capital expenditures in 2019 when activity levels were higher and reduced capital expenditures in 2020 due to lower activity and commodity prices.

	Year Ended December 31,		
Corporate	**2020**	**2019**	**% Change**
	(Dollars in thousands)		
Selling, general and administrative	$75,612	$ 89,831	(15.8)%
Restructuring expenses	$ 901	$ —	NA
Depreciation	$ 6,494	$ 6,888	(5.7)%
Other operating expenses (income), net			
Net gain on asset disposals	$ (3,079)	$(13,904)	(77.9)%
Legal-related expenses and settlements, net of insurance reimbursements	1,680	(3,471)	NA
Research and development	3,411	3,840	(11.2)%
Other	9,232	11,230	(17.8)%
Other operating expense (income), net	$11,244	$ (2,305)	NA
Credit loss expense	$ 5,606	$ 5,683	(1.4)%
Interest income	$ 1,254	$ 6,013	(79.1)%
Interest expense	$40,770	$ 75,204	(45.8)%
Other income	$ 756	$ 389	94.3%
Capital expenditures	$ 1,707	$ 4,612	(63.0)%

Selling, general and administrative expense decreased primarily as a result of cost reduction efforts.

Restructuring expenses were recognized in 2020 and were primarily attributable to severance and right-of-use asset abandonments. See Note 20 of Notes to Consolidated Financial Statements for additional information.

Other operating expenses (income), net includes net gains or losses associated with the disposal of assets. Accordingly, the related gains or losses have been excluded from the results of specific segments. The majority of the net gain on asset disposals during 2019 reflect gains on disposal of drilling equipment. Legal-related expenses and settlements in 2019 includes proceeds from insurance claims.

Other expenses, net include charges of $9.2 million and $12.7 million in 2020 and 2019, respectively related to a 2017 capacity reservation agreement that required a cash deposit to increase our access to finer grades of sand for our pressure pumping business. As market prices for sand substantially decreased since 2017, we purchased lower cost sand outside of this capacity reservation contract and revalued the deposit at its expected realizable value. There is no value assigned to the capacity reservation contract subsequent to the charge recorded in the second quarter of 2020.

A provision for credit losses was recognized in the twelve months ended December 31, 2020 with respect to accounts receivable balances that are estimated to be uncollectible.

Interest expense was lower in the twelve months ended December 31, 2020. Interest expense for the twelve months ended December 31, 2019 included a loss on debt extinguishment of $24.0 million as a result of full prepayment of the Series A Notes and Series B Notes (as defined below). Additionally, interest expense for the twelve months ended December 31, 2020 included a gain on debt extinguishment of $3.6 million associated with the repurchase of portions of our 2028 Notes and 2029 Notes.

Comparison of the years ended December 31, 2019 and 2018

A discussion of our results of operations for the fiscal year ended December 31, 2019 compared to the fiscal year ended December 31, 2018 is included in Part II, Item 7— "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended December 31, 2019, filed with the SEC on February 13, 2020.

Income Taxes

The effective tax rate decreased by approximately 6% to 13.7% for 2020 compared to 19.7% for 2019. This difference was primarily due to higher goodwill impairment charges in 2020 relative to 2019, which are not deductible for tax purposes. These charges resulted in an 8.2% decrease to the effective tax rate in 2020, as compared to a 0.7% decrease to the effective tax rate in 2019.

We continue to monitor income tax developments in the United States and other countries where we have legal entities. During 2020, the United States enacted various legislation related to COVID-19 relief, which includes multiple tax provisions. We have considered these tax provisions and do not currently expect any material impact to our financial statements. We will incorporate into our future financial statements the impacts, if any, of future regulations and additional authoritative guidance when finalized.

Liquidity and Capital Resources

During the second quarter of 2020, we implemented a restructuring plan to improve operating margins, achieve operational efficiencies and reduce indirect support costs. The restructuring included workforce reductions, changes to management structure and facility consolidations and closures. We recorded $38.3 million of charges associated with this plan in second quarter of 2020. There were no restructuring charges in the comparable periods of 2019. We completed the restructuring plan during the third quarter of 2020 and did not incur additional expenses related to the plan.

While oilfield services activity and revenues declined significantly throughout 2020, we aligned our cost structure with the changing activity levels and enhanced our liquidity position. Our liquidity as of December 31, 2020 included approximately $204 million in working capital, $225 million of cash and cash equivalents, and approximately $600 million available under our revolving credit facility.

On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 2028 Notes. We used $239 million of the net proceeds from the offering to repay amounts outstanding under our revolving credit facility. As described below, on March 27, 2018, we entered into an amended and restated credit agreement, which is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million.

On August 22, 2019, we entered into the Term Loan Agreement, which permitted a single borrowing of up to $150 million initially, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. On September 25, 2019, we used $150 million of borrowings from the Term Loan Agreement and approximately $158 million of cash on hand to prepay the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, plus accrued interest to the prepayment date. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and an additional $50 million on December 24, 2020. As of December 31, 2020, we had $50 million in borrowings remaining under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. The maturity date of the Term Loan Agreement is June 10, 2022.

On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of the 2029 Notes. The net proceeds before offering expenses were approximately $347 million. On December 16, 2019, we used a portion of the net proceeds from the offering to prepay the Series B Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, plus accrued interest to the prepayment date. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement.

On March 27, 2020, we entered into Amendment No. 2 to Amended and Restated Credit Agreement to, among other things, extend the maturity date for $550 million of revolving credit commitments of certain lenders under the Credit Agreement from March 27, 2024 to March 27, 2025. We have the option, subject to certain conditions, to exercise an additional one-year extension of the maturity date.

During the fourth quarter of 2020, we elected to repurchase portions of our Senior Notes due 2028 and 2029 in the open market. The principal amounts retired through these transactions totaled $15.5 million related to our 2028 Notes and $0.8 million related to our 2029 Notes, plus accrued interest. We recorded corresponding gains on the extinguishment of these amounts totaling $3.4 million and $0.2 million, respectively, net of the proportional write-off of associated deferred financing costs and original issuance discounts. These gains are included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

We believe our current liquidity, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt and pay cash dividends for at least the next 12 months.

If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash flows from operating activities, borrowing capacity under our revolving credit facility or 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, 2020, we had working capital of $204 million, including cash and cash equivalents of $225 million, compared to working capital of $231 million, including cash and cash equivalents of $174 million, at December 31, 2019.

During 2020, our sources of cash flow included:

- $279 million from operating activities,
- $20.9 million in proceeds from the disposal of property and equipment and insurance claims.

During 2020, we used $18.9 million to pay dividends on our common stock, $21.2 million for repurchases of our common stock, $12.0 million for repurchases of our 2028 Notes, $0.6 million for repurchases of our 2029 Notes, $50.0 million to repay a portion of the outstanding borrowings under our Term Loan Agreement due June 2022, and $145 million:

- to make capital expenditures for the betterment and refurbishment of drilling and pressure pumping equipment and, to a much lesser extent, equipment for our other businesses,
- to acquire and procure equipment to support our drilling, pressure pumping, directional drilling, oilfield rentals and manufacturing 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, 2020 as follows:

	Per Share	Total
		(in thousands)
Paid on March 19, 2020	$0.04	$ 7,629
Paid on June 18, 2020	0.02	3,735
Paid on September 17, 2020	0.02	3,746
Paid on December 17, 2020	0.02	3,752
Total cash dividends	$0.10	$18,862

On February 3, 2021, 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 18, 2021 to holders of record as of March 4, 2021. 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.

We may, at any time and from time to time, seek to retire or purchase our outstanding debt for cash through open-market purchases, privately negotiated transactions, redemptions or otherwise. Such repurchases, if any, will be upon such terms and at such prices as we may determine, and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

On September 6, 2013, our Board of Directors approved a stock buyback program that authorized purchases of up to $200 million of our common stock in open market or privately negotiated transactions. On July 25, 2018, our Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 6, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 24, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. All purchases executed to date have been through open market transactions. Purchases under the program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. Shares of stock purchased under the buyback program are held as treasury shares. There is no expiration date associated with the buyback program. As of December 31, 2020, we had remaining authorization to purchase approximately $130 million of our outstanding common stock under the stock buyback program.

We acquired shares of stock from employees during 2020, 2019 and 2018 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price and employees' tax withholding obligations upon the exercise of stock options. The remainder of these shares were acquired to satisfy payroll withholding obligations upon the settlement of performance unit awards and the vesting of restricted stock and restricted stock units. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan, as amended, and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2020, 2019 and 2018 were as follows (dollars in thousands):

	2020		2019		2018	
	Shares	**Cost**	**Shares**	**Cost**	**Shares**	**Cost**
Treasury shares at beginning of period	77,336,387	$1,345,134	53,701,096	$1,080,448	43,802,611	$ 918,711
Purchases pursuant to stock buyback program	5,826,266	20,000	22,566,331	250,109	9,331,131	150,497
Acquisitions pursuant to long-term incentive plan	239,669	1,179	1,037,947	14,205	567,354	11,240
Other	—	—	31,013	372	—	—
Treasury shares at end of period	83,402,322	$1,366,313	77,336,387	$1,345,134	53,701,096	$1,080,448

2019 Term Loan Agreement — On August 22, 2019, we entered into a term loan agreement ("Term Loan Agreement") among us, as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto.

The Term Loan Agreement is a committed senior unsecured term loan facility that permitted a single borrowing of up to $150 million initially, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and an additional $50 million on December 24, 2020. As of December 31, 2020, we had $50 million in borrowings remaining under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. The maturity date under the Term Loan Agreement is June 10, 2022.

Loans under the Term Loan Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans and base rate loans was 1.375% and 0.375%, respectively.

The Term Loan Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and the ability of each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade at both Moody's and S&P, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Term Loan Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. Restricted payments include, among other things, dividend payments, repurchases of our common stock, distributions to holders of our common stock or any other payment or other distribution to third parties on account of our or our subsidiaries' equity interests. Our credit rating is currently investment grade at one of the two ratings agencies.

The Term Loan Agreement requires mandatory prepayment in an amount equal to 100% of the net cash proceeds from the issuance of new senior indebtedness (other than certain permitted indebtedness) if our credit rating is below investment grade at both Moody's and S&P. Our credit rating is currently investment grade at one of the two ratings agencies. The Term Loan Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Term Loan Agreement generally defines the total 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 end of the most recently ended fiscal quarter. We were in compliance with these covenants at December 31, 2020.

Credit Agreement — On March 27, 2018, we entered into an amended and restated credit agreement (the "Credit Agreement") among us, as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender, each of the other lenders and letter of credit issuers party thereto, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Syndication Agents, Royal Bank of Canada, as Documentation Agent and Wells Fargo Securities, LLC, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Lead Arrangers and Joint Book Runners.

The Credit Agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $300 million, not to exceed total commitments of $900 million. The original maturity date under the Credit Agreement was March 27, 2023. On March 26, 2019, we entered into Amendment No. 1 to Amended and Restated Credit Agreement, which amended the Credit Agreement to, among other things, extend the maturity date under the Credit Agreement from March 27, 2023 to March 27, 2024. On March 27, 2020, we entered into Amendment No. 2 to Amended and Restated Credit Agreement to, among other things, extend the maturity date for $550 million of revolving credit commitments of certain lenders under the Credit Agreement from March 27, 2024 to March 27, 2025. We have the option, subject to certain conditions, to exercise an additional one-year extension of the maturity date.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans was 1.75% and the applicable margin on base rate loans was 0.75%. 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 varies from 0.10% to 0.30% based on our credit rating.

None of our subsidiaries are currently required to be a guarantor under the Credit Agreement. However, if any subsidiary guarantees or incurs debt in excess of the Priority Debt Basket (as defined in the Credit Agreement), such subsidiary is required to become a guarantor under the Credit Agreement.

The Credit Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and the ability of each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade at both Moody's and S&P, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. Restricted payments include, among other things, dividend payments, repurchases of our common stock, distributions to holders of our common stock or any other payment or other distribution to third parties on account of our or our subsidiaries' equity interests. Our credit rating is currently investment grade at one of the two ratings agencies. The Credit Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Credit Agreement generally defines the total 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 end of the most recently ended fiscal quarter. We were in compliance with these covenants at December 31, 2020.

As of December 31, 2020, we had no borrowings outstanding under our revolving credit facility. We had $0.1 million in letters of credit outstanding under the Credit Agreement at December 31, 2020 and, as a result, had available borrowing capacity of approximately $600 million at that date.

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, 2020, we had $60.7 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 by us 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 or 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, 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. None of our subsidiaries are currently required to guarantee payment under the Credit Agreement.

Series A Senior Notes and Series B 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 bore interest at a rate of 4.97% per annum. On September 25, 2019, we fully prepaid the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bore interest at a rate of 4.27% per annum. On December 16, 2019, we fully prepaid the Series B

Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

Primarily as a result of the "make-whole" premiums, we incurred an $8.2 million loss on early extinguishment of the Series A Notes in the three months ended September 30, 2019, and a $15.8 million loss on early extinguishment of the Series B Notes in the three months ended December 31, 2019, which were included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

2028 Senior Notes and 2029 Senior Notes — On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 3.95% Senior Notes due 2028 (the "2028 Notes"). The net proceeds before offering expenses were approximately $521 million, of which we used $239 million to repay amounts outstanding under our revolving credit facility. On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of our 5.15% Senior Notes due 2029 (the "2029 Notes"). The net proceeds before offering expenses were approximately $347 million. We used a portion of the net proceeds from the offering to prepay our Series B Notes. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement in 2019.

During the fourth quarter of 2020, we elected to repurchase portions of our 2028 Notes and 2029 Notes in the open market. The principal amounts retired through these transactions totaled $15.5 million related to our 2028 Notes and $0.8 million related to our 2029 Notes, plus accrued interest. We recorded corresponding gains on the extinguishment of these amounts totaling $3.4 million and $0.2 million, respectively, net of the proportional write-off of associated deferred financing costs and original issuance discounts. These gains are included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

We pay interest on the 2028 Notes on February 1 and August 1 of each year. The 2028 Notes will mature on February 1, 2028. The 2028 Notes bear interest at a rate of 3.95% per annum.

We pay interest on the 2029 Notes on May 15 and November 15 of each year. The 2029 Notes will mature on November 15, 2029. The 2029 Notes bear interest at a rate of 5.15% per annum.

The 2028 Notes and 2029 Notes (together, the "Senior Notes") are our senior unsecured obligations, which rank equally with all of our other existing and future senior unsecured debt and will rank senior in right of payment to all of our other future subordinated debt. The Senior Notes will be effectively subordinated to any of our future secured debt to the extent of the value of the assets securing such debt. In addition, the Senior Notes will be structurally subordinated to the liabilities (including trade payables) of our subsidiaries that do not guarantee the Senior Notes. None of our subsidiaries are currently required to be a guarantor under the Senior Notes. If our subsidiaries guarantee the Senior Notes in the future, such guarantees (the "Guarantees") will rank equally in right of payment with all of the guarantors' future unsecured senior debt and senior in right of payment to all of the guarantors' future subordinated debt. The Guarantees will be effectively subordinated to any of the guarantors' future secured debt to the extent of the value of the assets securing such debt.

At our option, we may redeem the Senior Notes in whole or in part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date, plus a "make-whole" premium. Additionally, commencing on November 1, 2027, in the case of the 2028 Notes, and on August 15, 2029, in the case of the 2029 Notes, at our option, we may redeem the respective Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date.

The indentures pursuant to which the Senior Notes were issued include covenants that, among other things, limit our and our subsidiaries' ability to incur certain liens, engage in sale and lease-back transactions or consolidate, merge, or transfer all or substantially all of their assets. These covenants are subject to important qualifications and limitations set forth in the indentures.

Upon the occurrence of a change of control triggering event, as defined in the indentures, each holder of the Senior Notes may require us to purchase all or a portion of such holder's Senior Notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date.

The indentures also provide for events of default which, if any of them occurs, would permit or require the principal of, premium, if any, and accrued interest, if any, on the Senior Notes to become or to be declared due and payable.

Commitments — As of December 31, 2020, we maintained letters of credit in the aggregate amount of $60.8 million primarily 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, 2020, no amounts had been drawn under the letters of credit.

As of December 31, 2020, we had commitments to purchase major equipment totaling approximately $14.7 million for our drilling, pressure pumping, directional drilling and oilfield rentals businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. The agreements expire in years 2021 and 2022. As of December 31, 2020, the remaining obligation under these agreements was approximately $13.4 million, of which approximately $10.0 million and $3.4 million relate to 2021 and 2022, respectively. In the event the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall. In 2017, we entered into a capacity reservation agreement that required a cash deposit to increase our access to finer grades of sand for our pressure pumping business. As market prices for sand substantially decreased since 2017, we purchased lower cost sand outside of this capacity reservation contract and recorded a charge of $9.2 million and $12.7 million in the second quarters of 2020 and 2019, respectively, to revalue the deposit to its expected realizable value. There is no value assigned to the capacity reservation contract subsequent to the charge recorded in the second quarter of 2020.

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, 2020 (in thousands):

	Payments due by period				
	Total	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
2029 Notes (1)	$ 349,250	$ —	$ —	$ —	$349,250
Interest on 2029 Notes (2)	161,878	17,986	35,973	35,973	71,946
Term Loan Agreement (3)	50,000	—	50,000	—	—
Interest on Term Loan Agreement (4)	1,116	761	355	—	—
2028 Notes (5)	509,505	—	—	—	509,505
Interest on 2028 Notes (6)	150,941	20,125	40,251	40,251	50,314
Leases (7)	29,125	8,011	10,236	5,237	5,641
Equipment purchases (8)	14,738	14,738	—	—	—
Inventory purchases (9)	13,380	10,030	3,350	—	—
Total	$1,279,933	$71,651	$140,165	$81,461	$986,656

(1) Principal repayment of the 2029 Notes is required at maturity on November 15, 2029.
(2) Interest to be paid on the 2029 Notes using 5.15% coupon rate.
(3) Principal repayment of the Term Loan Agreement is required at maturity on June 10, 2022.
(4) Interest to be paid on Term Loan Agreement using a LIBOR-based interest rate of 1.52% rate in effect as of December 31, 2020.
(5) Principal repayment of the 2028 Notes is required at maturity on February 1, 2028.
(6) Interest to be paid on the 2028 Notes using 3.95% coupon rate.
(7) See Note 13 of Notes to Consolidated Financial Statements.
(8) Represents commitments to purchase major equipment to be delivered in 2021 based on expected delivery dates.
(9) 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, 2020.

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by accounting principles generally accepted in the United States of America ("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 because we believe it provides to both management and investors additional information with respect to the performance of our fundamental business activities and a comparison of the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measure of net income (loss). Our computations of Adjusted EBITDA may not be the same as other similarly titled measures of other companies. Set forth below is a reconciliation of the non-U.S. GAAP financial measure of Adjusted EBITDA to the U.S. GAAP financial measure of net income (loss).

	Year Ended December 31,		
	2020	2019	2018
	(Dollars in thousands)		
Net loss	$(803,692)	$ (425,703)	$(321,421)
Income tax benefit	(127,326)	(104,675)	(45,987)
Net interest expense	39,516	69,191	45,981
Depreciation, depletion, amortization and impairment	670,910	1,003,873	916,318
Impairment of goodwill	395,060	17,800	211,129
Adjusted EBITDA	$ 174,468	$ 560,486	$ 806,020

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, leases and the use of estimates.

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 inactive rigs to working condition and the expected demand for drilling services by rig type. The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to our other marketed rigs are transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs are retired. In the second quarter of 2020, we recorded an impairment of $8.3 million related to the closing of our Canadian drilling operations. In 2019, we identified 36 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believed the 36 rigs that were retired had limited commercial opportunity. We recorded a $173 million charge related to this retirement. In 2018, we identified 42 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believed the 42 rigs that were retired had limited commercial opportunity. We recorded a $48.4 million charge related to this retirement.

We also periodically evaluate our pressure pumping assets for marketability based on the condition of inactive equipment, expenditures that would be necessary to bring the equipment to working condition and the expected demand. The components of equipment that will no longer be marketed are evaluated, and those components with continuing utility will be used as parts to support active equipment. The remaining components of this equipment are retired. In 2019, we recorded a charge of $20.5 million for the write-down of pressure pumping equipment compared to a $17.4 million write-down of pressure pumping equipment in 2018. There was no similar charge in 2020.

We also periodically evaluate our directional drilling assets. During 2019, we recorded a charge of $8.4 million for the write-down of directional drilling equipment. There was no similar charge in 2020 or 2018.

We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the 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. 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 our 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.

2020 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in the first quarter of 2020, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of March 31, 2020. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of March 31, 2020. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 15%, 22%, 3% and 9%, respectively.

For the assessment performed in the first quarter of 2020, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the second half of 2019 and the first quarter of 2020 and would begin to recover in 2022 in response to improved oil prices. While we believed these assumptions with respect to future oil pricing were reasonable, actual future prices and activity levels may vary significantly from the ones that were assumed. The timeframe over which oil prices and activity levels may 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 those described in "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."

All of these factors are beyond our control. If the lower oil price environment experienced in 2020 were to last into late 2022 and beyond, our actual cash flows would likely be less than the expected cash flows used in these assessments and could result in impairment charges in the future, and such impairment charges could be material.

After the assessment we performed in the first quarter of 2020, we concluded that no triggering events occurred during the periods thereafter through December 31, 2020 with respect to our asset groups based on our recent results of operations, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices, our results of operations for the quarter ended September 30, 2019 and management's expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of September 30, 2019. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 35%, 54%, 23% and 7%, respectively.

For the assessment performed in 2019, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in 2019 and would begin to recover in late 2020 or 2021 in response to improved oil prices.

We concluded that no triggering events occurred during the quarter ended December 31, 2019 with respect to our asset groups based on our recent results of operations, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

2018 Triggering Event Assessment

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of December 31, 2018. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 38%, 58%, 9% and 23%, respectively.

For the assessment performed in 2018, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the fourth quarter of 2018, and would begin to recover in late 2019 and continue into 2020 in response to improved oil prices and activity levels.

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 impairment testing purposes, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing are our operating segments. We 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 this is the case, any necessary goodwill impairment is determined using a quantitative impairment test. From time to time, we may perform quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. If the resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized for the amount of the shortfall.

2020 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in the first quarter of 2020, we lowered our expectations with respect to future activity levels in our contract drilling reporting unit. We performed a quantitative impairment assessment of our goodwill as of March 31, 2020. In completing the assessment, the fair value of our contract drilling operating segment was estimated using the income approach. The estimate of fair value required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of March 31, 2020, impairment was indicated in our contract drilling reporting unit. We recognized an impairment charge of $395 million in the quarter ended March 31, 2020 associated with the impairment of all of the goodwill in our contract drilling reporting unit. We had no remaining goodwill balance as of December 31, 2020.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and recent commodity prices, our results of operations for the quarter ended September 30, 2019 and our expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of September 30, 2019. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of September 30, 2019, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 13% and we concluded that no impairment was indicated in our contract drilling reporting unit; however, impairment was indicated in our oilfield rentals and electrical controls and automation reporting units included in the other operations segment. We recognized an impairment charge of $17.8 million in 2019 associated with the impairment of all of the goodwill in our oilfield rentals and electrical controls and automation reporting units.

In connection with our annual goodwill impairment assessment as of December 31, 2019, 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 the respective carrying amount. In making this determination, we considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in our reporting units, as well as our 2019 operating results and forecasted operating results for the succeeding year. We also considered our overall market capitalization at December 31, 2019.

2018 Triggering Event Assessment

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of December 31, 2018. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of December 31, 2018, the fair value of the contract drilling and oilfield rentals reporting units exceeded their carrying values by approximately 16% and 14%, respectively, and we concluded that no impairment was indicated in our contract drilling and oilfield rentals reporting units; however, impairment was indicated in our pressure pumping and directional drilling reporting units. We recognized an impairment charge of $211 million associated with the impairment of all of the goodwill in our pressure pumping and directional drilling reporting units.

Revenue recognition — On January 1, 2018, we adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on our consolidated financial statements, and a cumulative adjustment was not recognized. Revenues for reporting periods beginning after January 1, 2018 are presented under Topic 606, while revenues prior to January 1, 2018 continue to be reported under previous revenue recognition requirements of Topic 605.

Leases — On January 1, 2019, we adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. We have elected to report all leases at the beginning of the period of adoption and not restate our comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. See Note 13 for Notes to consolidated financial statements for additional information.

Use of estimates — The preparation of financial statements in conformity with 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 credit losses,
- 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.

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.

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. Oil prices remain extremely volatile, as the closing price of oil (WTI-Cushing) reached a first quarter 2020 high of $63.27 per barrel on January 6, 2020, declined to negative $36.98 per barrel on April 20, 2020, and closed at $53.55 per barrel on February 1, 2021. In response to the rapid decline in commodity prices, E&P companies acted swiftly to reduce drilling and completion activity starting late in the first quarter of 2020. While oil prices have recovered from the lows experienced in the first half of 2020, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our pressure pumping horsepower remains stacked. Oil prices averaged $42.45 per barrel in the fourth quarter of 2020.

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, as well as our customers' ability to access sources of capital to fund their operating and capital expenditures. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices, expectations of decreases in oil and natural gas prices or a reduction in the ability of our customers to access capital, would likely result in 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 historically moderate or 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, 2020. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

As of December 31, 2020, we had exposure to interest rate market risk associated with our borrowings under the Term Loan Agreement, and we would have had exposure to interest rate market risk associated with any borrowings that we had under the Credit Agreement and amounts owed under the Reimbursement Agreement.

Loans under the Term Loan Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans and base rate loans was 1.375% and 0.375%, respectively. As of December 31, 2020, we had $50 million in borrowings outstanding under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. A one percent increase in the interest rate on the borrowings outstanding under the Term Loan Agreement as of December 31, 2020 would increase our annual cash interest expense by $0.5 million.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based on our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans was 1.75% and the applicable margin on base rate loans was 0.75%. As of December 31, 2020, we had no borrowings outstanding under our revolving credit facility. The interest rate on borrowings outstanding under our revolving credit facility is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate.

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. We are obligated to pay Scotiabank 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, 2020, no amounts had been disbursed under any letters of credit.

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, 2020, 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, 2020, 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, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 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 within four business days following the date of the amendment or waiver.

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.

3.1	Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to our Quarterly Report on Form 10-Q 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 our Quarterly Report on Form 10-Q 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 our Current Report on Form 8-K and incorporated herein by reference).
3.4	Certificate of Amendment to Restated Certificate of Incorporation, as amended (filed July 30, 2018 as Exhibit 3.4 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018 and incorporated herein by reference).
3.5	Fourth Amended and Restated Bylaws (filed February 12, 2019 as Exhibit 3.1 to our Current Report on Form 8-K and incorporated herein by reference).
3.6	Certificate of Designation of the Series A Junior Participating Preferred Stock of Patterson-UTI Energy, Inc., dated April 22, 2020 (filed April 23, 2020 as Exhibit 3.1 to our Current Report on Form 8-K and incorporated herein by reference).
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934. +
4.2	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 our Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).
4.3	Base Indenture, dated January 19, 2018, among Patterson-UTI Energy, Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed January 19, 2018 as Exhibit 4.1 to our Current Report on Form 8-K and incorporated herein by reference).
4.4	First Supplemental Indenture, dated January 19, 2018, among Patterson-UTI Energy, Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed January 19, 2018 as Exhibit 4.2 to our Current Report on Form 8-K and incorporated herein by reference).
4.5	Form of 3.95% Senior Note due 2028 (included in Exhibit 4.4 above).
4.6	Base Indenture, dated November 15, 2019, between Patterson-UTI Energy, Inc. and U.S. Bank National Association, as trustee (filed November 15, 2019 as Exhibit 4.1 to our Current Report on Form 8-K and incorporated herein by reference).
4.7	First Supplemental Indenture, dated November 15, 2019, between Patterson-UTI Energy, Inc. and U.S. Bank National Association, as trustee (filed November 15, 2019 as Exhibit 4.2 to our Current Report on Form 8-K and incorporated herein by reference).
4.8	Form of 5.15% Senior Note due 2029 (included in Exhibit 4.7 above).

4.9	Stockholder Rights Agreement, dated as of April 22, 2020, by and between Patterson-UTI Energy, Inc. and Continental Stock Transfer & Trust Company, as rights agent (which includes the Form of Rights Certificate as Exhibit B thereto) (filed April 23, 2020 as Exhibit 4.1 to our Current Report on Form 8-K and incorporated herein by reference).
4.10	First Amendment to Stockholder Rights Agreement, dated as of July 22, 2020, by and between Patterson-UTI Energy, Inc. and Continental Stock Transfer & Trust Company, as rights agent (filed July 23, 2020 as Exhibit 4.1 to our Current Report on Form 8-K and incorporated herein by reference).
10.1	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 our Current Report on Form 8-K and incorporated herein by reference).*
10.2	First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.3	Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to our Current Report on Form 8-K and incorporated herein by reference).*
10.4	Third Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.5	Fourth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.2 to our Current Report on Form 8-K and incorporated herein by reference).*
10.6	Fifth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.4 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.7	Patterson-UTI Energy, Inc. Omnibus Incentive Plan (filed April 21, 2017 as Exhibit 4.4 to our Registration Statement on Form S-8 and incorporated herein by reference).*
10.8	Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (filed April 21, 2014 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.9	Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (as amended and restated effective June 29, 2017) (filed June 30, 2017 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.10	Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan, as amended and restated and further amended effective June 6, 2019 (filed June 6, 2019 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.11	Form of Executive Officer Restricted Stock Unit Award Agreement (filed August 4, 2017 as Exhibit 10.5 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.12	Form of Executive Officer Stock Option Agreement (filed April 21, 2014 as Exhibit 10.4 to our Current Report on Form 8-K and incorporated herein by reference).*
10.13	Form of Non-Employee Director Stock Option Agreement (filed April 21, 2014 as Exhibit 10.6 to our Current Report on Form 8-K and incorporated herein by reference).*
10.14	Form of Non-Employee Director Restricted Stock Unit Award Agreement (filed April 28, 2020 as Exhibit 10.11 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*

10.15	Form of Executive Officer Share-Settled Performance Share Award Agreement (filed July 28, 2020 as Exhibit 10.1 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.16	2020 Phantom Unit Award Agreement, dated May 11, 2020, by and between Patterson-UTI Energy, Inc. and William A. Hendricks, Jr. (filed July 28, 2020 as Exhibit 10.2 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.17	Amendment No. 1 to Performance Share Award Agreement, dated May 11, 2020, by and between Patterson-UTI Energy, Inc. and William A. Hendricks, Jr. (filed July 28, 2020 as Exhibit 10.2 to our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.18	Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with Kenneth N. Berns (filed on February 25, 2005 as Exhibit 10.23 to our Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*
10.19	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 our Current Report on Form 8-K and incorporated herein by reference).*
10.20	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 our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.21	Employment Agreement, effective as of August 1, 2016, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed February 13, 2017 as Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2016 and incorporated herein by reference).*
10.22	Employment Agreement, dated as of September 3, 2017, between Patterson-UTI Energy, Inc. and C. Andrew Smith (filed September 8, 2017 as Exhibit 10.2 to our Current Report on Form 8-K and incorporated herein by reference).*
10.23	Employment Agreement, dated as of April 8, 2020, between Patterson-UTI Management Services, LLC and Mark S. Siegel (filed April 9, 2020 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).*
10.24	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, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon, Tiffany J. Thom, C. Andrew Smith and Janeen S. Judah (filed April 28, 2004 as Exhibit 10.11 to our Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*
10.25	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 our Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.26	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 our Quarterly Report on Form 10-Q and incorporated herein by reference).*
10.27	Amended and Restated Credit Agreement dated March 27, 2018 among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuers and lenders party thereto (filed March 27, 2018 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).

10.28	Amendment No. 1 to Amended and Restated Credit Agreement, dated March 26, 2019, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuers and lenders party thereto (filed March 26, 2019 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).
10.29	Amendment No. 2 to Amended and Restated Credit Agreement, dated March 27, 2020, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuers and lenders party thereto (filed March 27, 2020 as Exhibit 10.1 to our Current Report on Form 8-K and incorporated herein by reference).
10.30	Reimbursement Agreement, dated as of 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 our Current Report on Form 8-K and incorporated herein by reference).
10.31	Term Loan Agreement, dated August 22, 2019, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto (filed August 23, 2019 as Exhibit 10.1 to our 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.INS	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.+
101.SCH	Inline XBRL Taxonomy Extension Schema Document+
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document+
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document+
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document+
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document+
104	Cover Page Interactive Data File (formatted as inline XBRL with applicable taxonomy extension information contained in Exhibits 101).

---

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

\+ Filed herewith.

++ Furnished 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.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Patterson-UTI Energy, Inc. and its subsidiaries (the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of operations, of comprehensive income (loss), of changes in stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2020, including the related notes and schedule of valuation and qualifying accounts for each of the three years in the period ended December 31, 2020 appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Long-lived Assets and Intangible Assets Recoverability Test—Asset Groupings in the Contract Drilling, Pressure Pumping, and Directional Drilling Operating Segments as of March 31, 2020

As described in Notes 6 and 7 to the consolidated financial statements, the Company's consolidated net property and equipment and consolidated intangible assets balance were $2,761 million and $30 million, respectively, most of which relates to the Contract Drilling and Pressure Pumping asset groupings as of December 31, 2020. Management reviews its long-lived assets, including property and equipment and intangibles, for impairment whenever events or changes in circumstances indicate that their carrying amounts of certain asset groupings may not be recovered over their estimated remaining useful lives. As a result of triggering events for the quarter ended March 31, 2020, management deemed it necessary to assess the recoverability of its contract drilling, pressure pumping, and directional drilling asset groups as of March 31, 2020. Management performed an analysis to assess the recoverability of the asset groups within its contract drilling, pressure pumping and directional drilling operating segments as of March 31, 2020. With respect to these asset groups, future cash flows were estimated over the expected remaining life of the assets, and management determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the asset groups, and no impairment was indicated. For the assessment performed in 2020, the expected cash flows for the Company's asset groups included revenue growth rates and operating expense growth rates.

The principal considerations for our determination that performing procedures relating to the Long-lived Assets and Intangible Assets Recoverability Test – Asset Groupings in the Contract Drilling, Pressure Pumping, and Directional Drilling Operating Segments as of March 31, 2020 is a critical audit matter are the significant judgment by management in estimating the future undiscounted cash flows of the asset groupings which, in turn, led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence obtained related to the significant assumptions in management's cash flow projections related to revenue growth rates for all three asset groupings and operating expense growth rates for the directional drilling asset grouping.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s long-lived assets and intangible assets recoverability test, including controls over the estimation of the undiscounted future cash flows of the Company’s asset groupings. These procedures also included, among others, evaluating the appropriateness of the method, testing the completeness, accuracy, and relevance of the underlying data used in the cash flows, and evaluating the reasonableness of significant assumptions used by management in developing their estimate of undiscounted future cash flows including revenue growth rates and operating expense growth rates. Evaluating management’s significant assumptions related to the revenue growth rates for all three asset groupings and operating expense growth rates for the directional drilling asset grouping, involved evaluating whether the significant assumptions used by management were reasonable considering the current and past performance of the asset groupings and considered whether they were consistent with evidence obtained in other areas of the audit.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 9, 2021

We have served as the Company’s auditor since 1993.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2020	December 31, 2019
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 224,915	$ 174,185
Accounts receivable, net of allowance for credit losses of $10,842 and $6,516 at December 31, 2020 and 2019, respectively	160,214	339,699
Federal and state income taxes receivable	4,428	6,397
Inventory	33,085	36,357
Other	55,314	75,177
Total current assets	477,956	631,815
Property and equipment, net	2,761,041	3,306,677
Right of use asset	16,850	31,275
Goodwill and intangible assets	30,087	444,004
Deposits on equipment purchases	1,716	8,066
Other	11,419	17,778
Total assets	$ 3,299,069	$ 4,439,615
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 91,622	$ 170,475
Federal and state income taxes payable	—	342
Accrued liabilities	175,004	219,850
Lease liability	7,096	9,935
Total current liabilities	273,722	400,602
Long-term lease liability	19,118	26,644
Long-term debt, net of debt discount and issuance costs of $7,271 and $8,460 at December 31, 2020 and 2019, respectively	901,484	966,540
Deferred tax liabilities, net	77,676	202,959
Other	11,010	9,250
Total liabilities	1,283,010	1,605,995
Commitments and contingencies (see Note 10)		
Stockholders' equity:		
Preferred stock, par value $0.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $0.01; authorized 400,000,000 shares with 271,028,688 and 269,372,257 issued and 187,626,366 and 192,035,870 outstanding at December 31, 2020 and 2019, respectively	2,710	2,694
Additional paid-in capital	2,902,236	2,875,680
Retained earnings	472,014	1,294,902
Accumulated other comprehensive income	5,412	5,478
Treasury stock, at cost, 83,402,322 shares and 77,336,387 shares at December 31, 2020 and 2019, respectively	(1,366,313)	(1,345,134)
Total stockholders' equity	2,016,059	2,833,620
Total liabilities and stockholders' equity	$ 3,299,069	$ 4,439,615

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,		
	2020	2019	2018
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$ 669,126	$1,308,350	$1,430,492
Pressure pumping	336,111	868,694	1,573,396
Directional drilling	73,356	188,786	209,275
Other	45,656	104,855	113,834
Total operating revenues	1,124,249	2,470,685	3,326,997
Operating costs and expenses:			
Contract drilling	380,822	785,355	885,704
Pressure pumping	310,261	724,788	1,263,850
Directional drilling	69,050	178,645	175,829
Other	41,790	84,909	77,104
Depreciation, depletion, amortization and impairment	670,910	1,003,873	916,318
Impairment of goodwill	395,060	17,800	211,129
Selling, general and administrative	97,611	133,513	134,071
Credit loss expense	5,606	5,683	—
Merger and integration expenses	—	—	2,738
Restructuring expenses	38,338	—	—
Other operating expenses (income), net	7,059	(2,305)	(17,569)
Total operating costs and expenses	2,016,507	2,932,261	3,649,174
Operating loss	(892,258)	(461,576)	(322,177)
Other income (expense):			
Interest income	1,254	6,013	5,597
Interest expense, net of amount capitalized	(40,770)	(75,204)	(51,578)
Other	756	389	750
Total other expense	(38,760)	(68,802)	(45,231)
Loss before income taxes	(931,018)	(530,378)	(367,408)
Income tax benefit	(127,326)	(104,675)	(45,987)
Net loss	$ (803,692)	$ (425,703)	$ (321,421)
Net loss per common share:			
Basic	$ (4.27)	$ (2.10)	$ (1.47)
Diluted	$ (4.27)	$ (2.10)	$ (1.47)
Weighted average number of common shares outstanding:			
Basic	188,013	203,039	218,643
Diluted	188,013	203,039	218,643

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,		
	2020	2019	2018
		(In thousands)	
Net loss	$(803,692)	$(425,703)	$(321,421)
Other comprehensive income (loss), net of taxes of $0 for 2020, $0 for 2019 and $0 for 2018:			
Foreign currency translation adjustment	(66)	2,991	(4,335)
Total comprehensive income (loss)	$(803,758)	$(422,712)	$(325,756)

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		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
	Number of Shares	Amount					
				(In thousands)			
Balance, December 31, 2017	266,259	$2,662	$2,785,823	$2,105,897	$ 6,822	$ (918,711)	$3,982,493
Net loss	—	—	—	(321,421)	—	—	(321,421)
Foreign currency translation adjustment	—	—	—	—	(4,335)	—	(4,335)
Restricted stock issued for acquisition	192	2	2,930	—	—	—	2,932
Issuance of restricted stock	381	4	(4)	—	—	—	—
Vesting of restricted stock units	452	5	(5)	—	—	—	—
Forfeitures of restricted stock	(8)	—	—	—	—	—	—
Exercise of stock options	40	—	485	—	—	—	485
Stock-based compensation	—	—	37,925	—	—	—	37,925
Payment of cash dividends	—	—	—	(30,589)	—	—	(30,589)
Dividend equivalents	—	—	—	(330)	—	—	(330)
Purchase of treasury stock	—	—	—	—	—	(161,737)	(161,737)
Balance, December 31, 2018	267,316	$2,673	$2,827,154	$1,753,557	$ 2,487	$(1,080,448)	$3,505,423
Net loss	—	—	—	(425,703)	—	—	(425,703)
Foreign currency translation adjustment	—	—	—	—	2,991	—	2,991
Issuance of restricted stock	185	2	(2)	—	—	—	—
Vesting of restricted stock units	1,173	12	(12)	—	—	—	—
Forfeitures of restricted stock	(2)	—	—	—	—	—	—
Exercise of stock options	700	7	9,212	—	—	—	9,219
Stock-based compensation	—	—	39,328	—	—	—	39,328
Payment of cash dividends	—	—	—	(32,428)	—	—	(32,428)
Dividend equivalents	—	—	—	(524)	—	—	(524)
Purchase of treasury stock	—	—	—	—	—	(264,686)	(264,686)
Balance, December 31, 2019	269,372	$2,694	$2,875,680	$1,294,902	$ 5,478	$(1,345,134)	$2,833,620
Net loss	—	—	—	(803,692)	—	—	(803,692)
Foreign currency translation adjustment	—	—	—	—	(66)	—	(66)
Issuance of restricted stock	333	3	(3)	—	—	—	—
Vesting of restricted stock units	1,324	13	(13)	—	—	—	—
Stock-based compensation	—	—	26,572	—	—	—	26,572
Payment of cash dividends	—	—	—	(18,862)	—	—	(18,862)
Dividend equivalents	—	—	—	(334)	—	—	(334)
Purchase of treasury stock	—	—	—	—	—	(21,179)	(21,179)
Balance, December 31, 2020	271,029	$2,710	$2,902,236	$ 472,014	$ 5,412	$(1,366,313)	$2,016,059

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,		
	2020	**2019**	**2018**
		(In thousands)	
Cash flows from operating activities:			
Net loss	$(803,692)	$ (425,703)	$(321,421)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	670,910	1,003,873	916,318
Impairment of goodwill	395,060	17,800	211,129
Dry holes and abandonments	1,285	109	915
Deferred income tax benefit	(125,283)	(103,202)	(41,185)
Stock-based compensation expense	26,572	39,328	37,925
Net gain on asset disposals	(3,079)	(13,904)	(28,958)
Net gain on insurance reimbursement	(4,172)	—	—
Write-down of capacity reservation contract	9,207	12,673	—
Credit loss expense	5,606	5,683	—
Restructuring expenses, non-cash	25,067	—	—
(Gain) loss on early debt extinguishment	(3,596)	24,023	—
Amortization of debt discount and issuance costs	912	937	830
Changes in operating assets and liabilities:			
Accounts receivable	173,862	213,588	23,515
Income taxes receivable/payable	1,635	(3,353)	(1,555)
Inventory and other assets	27,192	29,394	(1,470)
Accounts payable	(48,602)	(77,686)	(69,453)
Accrued liabilities	(59,240)	(18,218)	4,136
Other liabilities	(10,786)	(9,139)	(56)
Net cash provided by operating activities	278,858	696,203	730,670
Cash flows from investing activities:			
Acquisitions, net of cash acquired	—	(13)	(14,211)
Purchases of property and equipment	(145,481)	(347,512)	(641,458)
Proceeds from disposal of assets and insurance claims	20,929	45,761	47,357
Collection of note receivable	—	—	23,760
Other	(424)	—	—
Net cash used in investing activities	(124,976)	(301,764)	(584,552)
Cash flows from financing activities:			
Purchases of treasury stock	(21,179)	(255,467)	(161,737)
Dividends paid	(18,862)	(32,428)	(30,589)
Proceeds from long-term debt	—	496,969	521,194
Repayment of long-term debt	(62,525)	(673,443)	—
Proceeds from borrowings under revolving credit facility	—	—	79,000
Repayment of borrowings under revolving credit facility	—	—	(347,000)
Debt issuance costs	(584)	(852)	(4,489)
Proceeds from exercise of stock options	—	—	485
Net cash provided by (used in) financing activities	(103,150)	(465,221)	56,864
Effect of foreign exchange rate changes on cash	(2)	(62)	(781)
Net increase (decrease) in cash and cash equivalents	50,730	(70,844)	202,201
Cash and cash equivalents at beginning of year	174,185	245,029	42,828
Cash and cash equivalents at end of year	$ 224,915	$ 174,185	$ 245,029
Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			
Interest, net of capitalized interest of $431 in 2020, $732 in 2019 and $1,435 in 2018	$ (43,368)	$ (76,870)	$ (41,184)
Income taxes	3,709	(1,452)	3,172
Non-cash investing and financing activities:			
Receivable from property and equipment insurance	$ —	$ —	$ 15,000
Net increase (decrease) in payables for purchases of property and equipment	(30,241)	(40,857)	36,241
Issuance of common stock for business acquisitions	—	—	2,932
Net decrease in deposits on equipment purchases	6,350	3,974	4,311
Cashless exercise of stock options	—	9,219	—

The accompanying notes are an integral part of these 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 "we," "us," "our," "ours" and like terms), is 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. Our pressure pumping business operates primarily in Texas and the Appalachian region. We also provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States, and we provide services that improve the statistical accuracy of horizontal wellbore placement. We have other operations through which we provide oilfield rental tools in select markets in the United States. We also service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries, 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.

In the second quarter of 2020, we closed our Canadian drilling operations in response to our longer-term outlook for the western Canadian market. As a result of the closure, we recorded an impairment of $8.3 million.

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, we have no controlling financial interests in any other entity which would require consolidation. As used in these notes, "we," "us," "our," "ours" and like terms refer collectively to Patterson-UTI Energy, Inc. and its consolidated subsidiaries. Patterson-UTI Energy, Inc. conducts its business operations through its wholly-owned subsidiaries and has no employees or independent operations.

The U.S. dollar is the functional currency for all of our operations except for our Canadian operations, 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.

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 ("U.S. GAAP") 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 our contract drilling, pressure pumping, directional drilling, oilfield rentals, equipment servicing and electrical control and automation activities are recognized as services are performed. All of the wells we drilled in 2020, 2019 and 2018 were drilled under daywork contracts. Revenue from sales of products are recognized upon customer acceptance. Revenue is presented net of any sales tax charged to the customer that we are 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 our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred.

On January 1, 2018, we adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on our consolidated financial statements, and a cumulative adjustment was not recognized. See Note 3 for additional information.

Leases — We enter operating leases for operating locations, corporate offices and certain operating equipment. As of December 31, 2020, we did not have any finance leases.

On January 1, 2019, we adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. We have elected to report all leases at the beginning of the period of adoption and not restate our comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. See Note 13 for additional information.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount. The allowance for credit losses represents our estimate of the amount of probable credit losses existing in our accounts receivable. We review the adequacy of our allowance for credit losses 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 uncollectible, are charged against the allowance.

Inventories — Inventories consist primarily of sand and other products to be used in conjunction with our pressure pumping activities and materials used in our directional drilling and equipment servicing 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 our workers compensation insurance carrier for claims in excess of our deductible in the amount of $36.1 million and $39.0 million at December 31, 2020 and 2019, 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
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.

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.

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 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 our 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). 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 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. Impairment expense related to oil and natural gas properties of approximately $11.2 million, $2.2 million and $1.0 million was recorded for the years ended December 31, 2020, 2019 and 2018, respectively.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. We assess impairment of 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.

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. Our policy is to account for interest and penalties with respect to income taxes as operating expenses.

Stock-based compensation — We recognize 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 12).

As share-based compensation expense recognized in the consolidated statements of operations is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures, based on historical experience. Forfeitures are estimated at the time of grant and revised in subsequent periods if actual forfeitures differ from those estimates.

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

Recently Adopted 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. We adopted this new revenue guidance effective January 1, 2018, utilizing the modified retrospective method, and expanded our consolidated financial statement disclosures in order to comply with the update (See Note 3). The adoption of this update did not have a material impact on our consolidated financial statements.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The standard requires the lessee to recognize a lease liability along with a right-of-use asset for all leases with a term longer than one year. A lessee is permitted to make an accounting policy election to not recognize the lease liability and related right-of-use asset for leases with a term of one year or less. The provisions of this standard also apply to situations where we are the lessor. We adopted this new leasing guidance effective January 1, 2019 and expanded our consolidated financial statement disclosures in order to comply with the update (See Note 13). The adoption of this standard resulted in the recording of operating lease right-of-use assets of approximately $31.0 million and operating lease liabilities of approximately $35.8 million as of January 1, 2019.

In August 2016, the FASB issued an accounting standards update 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 in fiscal years beginning after December 15, 2017. The adoption of this update on January 1, 2018 did not have a material impact on our consolidated financial statements.

In May 2017, the FASB issued an accounting standards update that provided clarity on which changes to the terms or conditions of share-based payment awards require an entity to apply modification accounting provisions. The requirements in this update are effective during interim and annual periods in fiscal years beginning after December 15, 2017. The adoption of this update on January 1, 2018 did not have a material impact on our consolidated financial statements.

In March 2018, the FASB issued an accounting standards update to update the income tax accounting in U.S. GAAP to reflect the SEC interpretive guidance released on December 22, 2017, when significant U.S. tax law changes were enacted with the enactment of "H.R.1," also known as the "Tax Cuts and Jobs Act" ("U.S. Tax Reform"). The adoption of this update in March 2018 did not have a material impact on our consolidated financial statements, as we were already following the SEC guidance (See Note 14).

In June 2016, the FASB issued an accounting standards update on measurement of credit losses on financial instruments. The new guidance requires us to measure all expected credit losses for financial instruments held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. The new standard is effective for fiscal years beginning after December 15, 2019, including all interim periods within those years. We adopted ASU 2016-13 as of January 1, 2020. The adoption of this guidance and recognition of a loss allowance at an amount equal to expected credit losses for accounts receivable was not material and did not result in a transition adjustment to retained earnings. For more information regarding credit losses, see Note 4.

In August 2018, the FASB issued an accounting standards update to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The capitalized implementation costs of a hosting arrangement that is a service contract will be expensed over the term of the hosting arrangement. We adopted this new guidance on January 1, 2020 prospectively with respect to all implementation costs incurred after the date of adoption. There was no material impact on our consolidated financial statements.

In August 2018, the FASB issued an accounting standards update to eliminate certain disclosure requirements for fair value measurements for all entities, require public entities to disclose certain new information and modify certain disclosure requirements. The FASB developed the amendments to Topic 820 as part of its broader disclosure framework project, which aims to improve the effectiveness of disclosures in the notes to financial statements by focusing on requirements that clearly communicate the most important information to users of the financial statements. We adopted this new guidance on January 1, 2020 and there was no material impact on our consolidated financial statements.

Recently Issued Accounting Standards — In December 2019, the FASB issued an accounting standards update to simplify the accounting for income taxes. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2020, with early adoption permitted. We adopted this new guidance on January 1, 2021, and we do not expect this new guidance will have a material impact on our consolidated financial statements.

In March 2020, the FASB issued an accounting standards update to provide temporary optional expedients that simplify the accounting for contract modifications to existing debt agreements expected to arise from the market transition from LIBOR to alternative reference rates. The amendments in the update are effective as of March 12, 2020 through December 31, 2022 and may be applied to contract modifications from the beginning of an interim period that includes or is subsequent to March 12, 2020. We plan to adopt this standard when LIBOR is discontinued and are currently evaluating the impact of adoption on our consolidated financial statements.

During the third quarter of 2019, we identified and recorded out-of-period adjustments primarily related to the accounting for inventory in our directional drilling segment. We concluded that these adjustments were not material to the consolidated financial statements for any of the current or prior periods presented. The net adjustment is reflected as a $6.6 million increase to “Loss before income taxes” in the consolidated statements of operations for the year ended December 31, 2019.

2. Acquisitions

Current Power Solutions, Inc. (“Current Power”)

During October 2018, we acquired Current Power. Current Power is a provider of electrical controls and automation to the energy, marine and mining industries. This acquisition was not material to our consolidated financial statements.

Superior QC, LLC (“Superior QC”)

During February 2018, we acquired the business of Superior QC, including its assets and intellectual property. Superior QC is a provider of software and services used to improve the statistical accuracy of horizontal wellbore placement. Superior QC’s measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well. This acquisition was not material to our consolidated financial statements.

3. Revenues

ASC Topic 606 Revenue from Contracts with Customers

On January 1, 2018, we adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on our consolidated financial statements, and a cumulative adjustment was not recognized. Revenues for reporting periods beginning on or after January 1, 2018 are presented under Topic 606.

Our contracts with customers include both long-term and short-term contracts. Services that primarily generate revenue earned for us include the operating business segments of contract drilling, pressure pumping and directional drilling which comprise our reportable segments. We also derive revenues from our other operations, which include our operating business segments of oilfield rentals, equipment servicing, electrical controls and automation, and oil and natural gas working interests. For more information on our business segments, see Note 17.

Charges for services are considered a series of distinct services. Since each distinct service in a series would be satisfied over time if it were accounted for separately, and the entity would measure its progress towards satisfaction using the same measure of progress for each distinct service in the series, we are able to account for these integrated services as a single performance obligation that is satisfied over time.

The transaction price is the amount of consideration to which we expect to be entitled in exchange for transferring promised goods or services to a customer, based on terms of our contracts with our customers. The consideration promised in a contract with a customer may include fixed amounts and/or variable amounts. Payments received for services are considered variable consideration as the time in service will fluctuate as the services are provided. Topic 606 provides an allocation exception, which allows us to allocate variable consideration to one or more distinct services promised in a series of distinct services that form part of a single performance obligation as long as certain criteria are met. These criteria state that the variable payment must relate specifically to the entity’s efforts to satisfy the performance obligation or transfer the distinct good or service, and allocation of the variable consideration is consistent with the standards' allocation objective. Since payments received for services meet both of these criteria requirements, we recognize revenue when the service is performed.

An estimate of variable consideration should be constrained to the extent that it is not probable that a significant revenue reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Payments received for other types of consideration are fully constrained as they are highly susceptible to factors outside the entity's influence and therefore could be subject to a significant revenue reversal once resolved. As such, revenue received for these types of consideration is recognized when the service is performed.

Estimates of variable consideration are subject to change as facts and circumstances evolve. As such, we will evaluate our estimates of variable consideration that are subject to constraints throughout the contract period and revise estimates, if necessary, at the end of each reporting period.

We are a non-operating, working interest owner of oil and natural gas properties primarily located in Texas and New Mexico. The ownership terms are outlined in joint operating agreements for each well between the operator of the well and the various interest owners, including us, who are considered non-operators of the well. We receive revenue each period for our working interest in the well during the period. The revenue received for the working interests from these oil and gas properties does not fall under the scope of the new revenue standard, and therefore, will continue to be reported under current guidance ASC 932-323 *Extractive Activities – Oil and Gas, Investments – Equity Method and Joint Ventures.*

Reimbursement Revenue – Reimbursements for the purchase of supplies, equipment, personnel services, shipping and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred.

Operating Lease Revenue – Lease income from equipment that we lease to others is recognized on a straight-line basis over the lease term.

Our disaggregated revenue recognized from contracts with customers is included in Note 17.

Accounts Receivable and Contract Liabilities

Accounts receivable is our right to consideration once it becomes unconditional. Payment terms typically range from 30 to 60 days.

Accounts receivable balances were $158 million and $336 million as of December 31, 2020 and 2019, respectively. These balances do not include amounts related to our oil and gas working interests as those contracts are excluded from Topic 606. Accounts receivable balances are included in "Accounts receivable" in the consolidated balance sheets.

We do not have any significant contract asset balances. Contract liabilities include prepayments received from customers prior to the requested services being completed. Once the services are complete and have been invoiced, the prepayment is applied against the customer's account to offset the accounts receivable balance. Also included in contract liabilities are payments received from customers for the initial mobilization of newly constructed or upgraded rigs that were moved on location to the initial well site. These mobilization payments are allocated to the overall performance obligation and amortized over the initial term of the contract. During the year ended December 31, 2020 and 2019, approximately $0.1 million and $1.0 million, respectively, was amortized and recorded in drilling revenue.

Total contract liability balances were $0.6 million and $2.7 million as of December 31, 2020 and December 31, 2019, respectively. Contract liability balances are included in "Accounts payable" and "Accrued liabilities" in the consolidated balance sheets.

Contract Costs

Costs incurred for newly constructed rigs or rig upgrades based on a contract with a customer are considered capital improvements and are capitalized to drilling equipment and depreciated over the estimated useful life of the asset.

Practical Expedients Adopted with Topic 606

We have elected to adopt the following practical expedients upon the transition date to Topic 606 on January 1, 2018:

- Use of portfolio approach: An entity can apply this guidance to a portfolio of contracts (or performance obligations) with similar characteristics if the entity reasonably expects that the effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying this guidance to the individual contracts (or performance obligations) within that portfolio
- Excluding disclosure about transaction price: As a practical expedient, an entity need not disclose the information for a performance obligation if either of the following conditions is met:
    a) The performance obligation is part of a contract that has an original expected duration of one year or less.
    b) The entity recognizes revenue from the satisfaction of the performance obligation.
- Excluding sales taxes from the transaction price: The scope of this policy election is the same as the scope of the policy election under previous guidance. This election provides exclusion from the measurement of the transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue producing transaction and collected by the entity from a customer.
- We do not disclose information about the transaction price allocated to remaining performance obligations and when revenue will be recognized because we recognize revenue equal to what we have the right to invoice when that amount corresponds directly with the value to the customer of the entity's performance to date.
- Costs of obtaining a contract: An entity can immediately expense costs of obtaining a contract if they would be amortized within a year.

4. Credit Losses

ASC Topic 326 Current Expected Credit Losses (CECL)

On January 1, 2020, we adopted ASU 2016-13 *Financial Instruments – Credit Losses (Topic 326) Measurement of Credit Losses on Financial Instruments*, which introduces a new model to measure all expected credit losses for financial instruments held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. Our customers are primarily oil and natural gas exploration and production companies, which are collectively exposed to oil and natural gas commodity price risk. Our customers require services from us at various stages of the exploration and production process. Accordingly, we have aggregated our trade receivables by segment. Any customers that have experienced a deterioration in credit quality are removed from the pool and evaluated individually. We utilized an accounts receivable aging schedule and historical credit loss information to estimate expected credit losses. Due to the significant decline in crude oil prices during the quarter ended March 31, 2020 and its related impact to our customers, we increased our historical credit loss rates used to determine our March 31, 2020 allowance for credit losses in the first quarter of 2020. We continued to monitor and evaluate our expected credit losses using these increased credit loss rates throughout the remainder of 2020.

The adoption of the new accounting standard did not have a material impact on our consolidated financial statements and did not result in a transition adjustment to retained earnings.

The allowance for credit losses related to accounts receivable as of December 31, 2020, and changes for the quarters ended March 31, June 30, September 30 and December 31, 2020 are as follows (in thousands):

Balance at December 31, 2019	$ 6,516
Provision for expected credit losses	1,055
Balance at March 31, 2020	7,571
Provision for expected credit losses	4,551
Balance at June 30, 2020	12,122
Write-offs	(1,126)
Balance at September 30, 2020	10,996
Write-offs	(154)
Balance at December 31, 2020	$10,842

5. Inventory

Inventory consisted of the following at December 31, 2020 and 2019 (in thousands):

	2020	2019
Finished goods	$ 600	$ 105
Work-in-process	802	1,229
Raw materials and supplies	31,683	35,023
Inventory	$33,085	$36,357

6. Property and Equipment

Property and equipment consisted of the following at December 31, 2020 and 2019 (in thousands):

	2020	2019
Equipment	$ 7,647,451	$ 8,114,326
Oil and natural gas properties	222,738	226,646
Buildings	193,503	184,700
Land	25,781	25,747
Total property and equipment	8,089,473	8,551,419
Less accumulated depreciation, depletion, amortization and impairment	(5,328,432)	(5,244,742)
Property and equipment, net	$ 2,761,041	$ 3,306,677

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment, intangible assets and liabilities for 2020, 2019 and 2018 (in thousands):

	2020	2019	2018
Depreciation and impairment expense	$644,943	$ 974,206	$887,155
Amortization expense	19,281	17,722	18,197
Depletion expense	6,686	11,945	10,966
Total	$670,910	$1,003,873	$916,318

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 inactive rigs to working condition and the expected demand for drilling services by rig type. The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to our other marketed rigs are transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs are retired. In the second quarter of 2020, we recorded an impairment of $8.3 million related to the closing of our Canadian drilling operations. In 2019, we identified 36 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believed the 36 rigs that were retired had limited commercial opportunity. We recorded a $173 million charge related to this retirement. In 2018, we identified 42 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believed the 42 rigs that were retired had limited commercial opportunity. We recorded a $48.4 million charge related to this retirement.

We also periodically evaluate our pressure pumping assets for marketability based on the condition of inactive equipment, expenditures that would be necessary to bring the equipment to working condition and the expected demand. The components of equipment that will no longer be marketed are evaluated, and those components with continuing utility will be used as parts to support active equipment. The remaining components of this equipment are retired. In 2019, we recorded a charge of $20.5 million for the write-down of pressure pumping equipment compared to a $17.4 million write-down of pressure pumping equipment in 2018. There was no similar charge in 2020.

We also periodically evaluate our directional drilling assets. During 2019, we recorded a charge of $8.4 million for the write-down of directional drilling equipment. There was no similar charge in 2020 or 2018.

We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the 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. 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 our 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.

2020 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in the first quarter of 2020, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of March 31, 2020. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of March 31, 2020. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 15%, 22%, 3% and 9%, respectively.

For the assessment performed in the first quarter of 2020, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the second half of 2019 and the first quarter of 2020 and would begin to recover in 2022 in response to improved oil prices. While we believed these assumptions with respect to future oil pricing were reasonable, actual future prices and activity levels may vary significantly from the ones that were assumed. The timeframe over which oil prices and activity levels may recover is highly uncertain.

All of these factors are beyond our control. If the lower oil price environment experienced in 2020 were to last into late 2022 and beyond, our actual cash flows would likely be less than the expected cash flows used in these assessments and could result in impairment charges in the future, and such impairment charges could be material.

After the assessment we performed in the first quarter of 2020, we concluded that no triggering events occurred during the periods thereafter through December 31, 2020 with respect to our asset groups based on our recent results of operations, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices, our results of operations for the quarter ended September 30, 2019 and management's expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of September 30, 2019. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 35%, 54%, 23% and 7%, respectively.

For the assessment performed in 2019, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in 2019 and would begin to recover in late 2020 or 2021 in response to improved oil prices.

We concluded that no triggering events occurred during the quarter ended December 31, 2019 with respect to our asset groups based on our recent results of operations, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

2018 Triggering Event Assessment

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of December 31, 2018. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 38%, 58%, 9% and 23%, respectively.

For the assessment performed in 2018, the expected cash flows for our asset groups included revenue and operating expense growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the fourth quarter of 2018, and would begin to recover in late 2019 and continue into 2020 in response to improved oil prices and activity levels.

7. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2020 and 2019 and changes for the years then ended are as follows (in thousands):

	Contract Drilling	Other Operations	Total
Balance, December 31, 2018	$ 395,060	$ 15,696	$ 410,756
Measurement period adjustment	—	$ 2,104	2,104
Impairment	—	(17,800)	(17,800)
Balance, December 31, 2019	$ 395,060	$ —	$ 395,060
Impairment	(395,060)	—	(395,060)
Balance, December 31, 2020	$ —	$ —	$ —

The change to goodwill in Other Operations in 2019 was primarily a result of a measurement period adjustment related to accrued liabilities, which resulted in a $2.1 million increase from the original purchase price allocation assessed with the Current Power acquisition.

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 impairment testing purposes, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing are our operating segments. We 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 this is the case, any necessary goodwill impairment is determined using a quantitative impairment test. From time to time, we may perform quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. If the resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized for the amount of the shortfall.

2020 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in the first quarter of 2020, we lowered our expectations with respect to future activity levels in our contract drilling reporting unit. We performed a quantitative impairment assessment of our goodwill as of March 31, 2020. In completing the assessment, the fair value of our contract drilling operating segment was estimated using the income approach. The estimate of fair value required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of March 31, 2020, impairment was indicated in our contract drilling reporting unit. We recognized an impairment charge of $395 million in the quarter ended March 31, 2020 associated with the impairment of all of the goodwill in our contract drilling reporting unit. We had no remaining goodwill balance as of December 31, 2020.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and recent commodity prices, our results of operations for the quarter ended September 30, 2019 and our expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of September 30, 2019. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of September 30, 2019, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 13% and we concluded that no impairment was indicated in our contract drilling reporting unit; however, impairment was indicated in our oilfield rentals and electrical controls and automation reporting units included in the other operations segment. We recognized an impairment charge of $17.8 million in 2019 associated with the impairment of all of the goodwill in our oilfield rentals and electrical controls and automation reporting units.

In connection with our annual goodwill impairment assessment as of December 31, 2019, 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 the respective carrying amount. In making this determination, we considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in our reporting units, as well as our 2019 operating results and forecasted operating results for the succeeding year. We also considered our overall market capitalization at December 31, 2019.

2018 *Triggering Event Assessment*

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of December 31, 2018. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of December 31, 2018, the fair value of the contract drilling and oilfield rentals reporting units exceeded their carrying values by approximately 16% and 14%, respectively, and we concluded that no impairment was indicated in our contract drilling and oilfield rentals reporting units; however, impairment was indicated in our pressure pumping and directional drilling reporting units. We recognized an impairment charge of $211 million associated with the impairment of all of the goodwill in our pressure pumping and directional drilling reporting units.

Intangible Assets — In 2018, intangible assets were recorded in our directional drilling operating segment with the acquisition of Superior QC and in other operations with the acquisition of Current Power. See Note 2 for additional information. Additionally, intangible assets were recorded in our directional drilling operating segment with the acquisition of MS Directional in 2017. Our intangible assets were recorded at fair value on the date of acquisition and are amortized on a straight-line basis. We have not incurred any costs to renew or extend the term of acquired intangible assets since the acquisition in 2018. The following table identifies the segment and weighted average useful life of each of our intangible assets:

	Segment	Weighted Average Useful Life
		(in years)
Customer relationships	Directional drilling	3.00
Customer relationships	Other operations	7.00
Developed technology	Directional drilling	5.89
Internal use software	Directional drilling	5.00

2020 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in the first quarter of 2020, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of March 31, 2020. The assessments of recoverability of the asset groups included the respective intangible assets, and no impairment was indicated. See Note 6 for additional information.

After the assessment we performed in the first quarter of 2020, we concluded that no triggering events necessitating an impairment assessment of the intangible assets occurred throughout the remainder of 2020.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and commodity prices in 2019, our results of operations for the quarter ended September 30, 2019 and our expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. The assessments of recoverability of the asset groups included the respective intangible assets, and no impairment was indicated. See Note 6 for additional information.

We concluded that no triggering events necessitating an impairment assessment of the intangible assets had occurred during the quarter ended December 31, 2019.

2018 Triggering Event Assessment

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of December 31, 2018. The assessments of recoverability of the asset groups included the respective intangible assets, and no impairment was indicated. See Note 6 for additional information.

The gross carrying amount and accumulated amortization of intangible assets as of December 31, 2020 and 2019 are as follows (in thousands):

	2020			**2019**		
	Gross Carrying Amount	**Accumulated Amortization**	**Net Carrying Amount**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**
Customer relationships	$28,000	$(26,757)	$ 1,243	$28,000	$(19,710)	$ 8,290
Developed technology	55,772	(27,515)	28,257	55,772	(15,386)	40,386
Internal use software	906	(319)	587	482	(214)	268
	$84,678	$(54,591)	$30,087	$84,254	$(35,310)	$48,944

Amortization expense on intangible assets of approximately $19.3 million, $17.9 million and $18.3 million was recorded for the years ended December 31, 2020, 2019 and 2018, respectively. The remaining amortization expense associated with finite-lived intangible assets is expected to be as follows (in thousands):

Year ending December 31,	
2021	$12,568
2022	12,546
2023	1,119
2024	1,119
2025	1,068
Thereafter	1,667
Total	$30,087

8. Accrued Liabilities

Accrued expenses consisted of the following at December 31, 2020 and 2019 (in thousands):

	2020	2019
Salaries, wages, payroll taxes and benefits	$ 37,627	$ 57,615
Workers' compensation liability	70,847	81,112
Property, sales, use and other taxes	10,666	22,404
Insurance, other than workers' compensation	8,462	9,218
Accrued interest payable	11,325	12,021
Accrued restructuring expenses	14,310	—
Other	21,767	37,480
Accrued liabilities	$175,004	$219,850

9. Long-Term Debt

2019 Term Loan Agreement — On August 22, 2019, we entered into a term loan agreement ("Term Loan Agreement") among us, as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto.

The Term Loan Agreement is a committed senior unsecured term loan facility that permitted a single borrowing of up to $150 million initially, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and an additional $50 million on December 24, 2020. As of December 31, 2020, we had $50 million in borrowings remaining under the Term Loan Agreement at a LIBOR-based interest rate of 1.52%. The maturity date under the Term Loan Agreement is June 10, 2022.

Loans under the Term Loan Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans and base rate loans was 1.375% and 0.375%, respectively.

The Term Loan Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and the ability of each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade at both Moody's and S&P, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Term Loan Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. Restricted payments include, among other things, dividend payments, repurchases of our common stock, distributions to holders of our common stock or any other payment or other distribution to third parties on account of our or our subsidiaries' equity interests. Our credit rating is currently investment grade at one of the two ratings agencies.

The Term Loan Agreement requires mandatory prepayment in an amount equal to 100% of the net cash proceeds from the issuance of new senior indebtedness (other than certain permitted indebtedness) if our credit rating is below investment grade at both Moody's and S&P. Our credit rating is currently investment grade at one of the two ratings agencies. The Term Loan Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Term Loan Agreement generally defines the total 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 end of the most recently ended fiscal quarter. We were in compliance with these covenants at December 31, 2020.

Credit Agreement — On March 27, 2018, we entered into an amended and restated credit agreement (the "Credit Agreement") among us, as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender, each of the other lenders and letter of credit issuers party thereto, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Syndication Agents, Royal Bank of Canada, as Documentation Agent and Wells Fargo Securities, LLC, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Lead Arrangers and Joint Book Runners.

The Credit Agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $300 million, not to exceed total commitments of $900 million. The original maturity date under the Credit Agreement was March 27, 2023. On March 26, 2019, we entered into Amendment No. 1 to Amended and Restated Credit Agreement, which amended the Credit Agreement to, among other things, extend the maturity date under the Credit Agreement from March 27, 2023 to March 27, 2024. On March 27, 2020, we entered into Amendment No. 2 to Amended and Restated Credit Agreement ("Amendment No. 2") to, among other things, extend the maturity date for $550 million of revolving credit commitments of certain lenders under the Credit Agreement from March 27, 2024 to March 27, 2025. We have the option, subject to certain conditions, to exercise an additional one-year extension of the maturity date.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon our credit rating. As of December 31, 2020, the applicable margin on LIBOR rate loans was 1.75% and the applicable margin on base rate loans was 0.75%. 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 varies from 0.10% to 0.30% based on our credit rating.

None of our subsidiaries are currently required to be a guarantor under the Credit Agreement. However, if any subsidiary guarantees or incurs debt in excess of the Priority Debt Basket (as defined in the Credit Agreement), such subsidiary is required to become a guarantor under the Credit Agreement.

The Credit Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and the ability of each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade at both Moody's and S&P, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. Restricted payments include, among other things, dividend payments, repurchases of our common stock, distributions to holders of our common stock or any other payment or other distribution to third parties on account of our or our subsidiaries' equity interests. Our credit rating is currently investment grade at one of the two ratings agencies. The Credit Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Credit Agreement generally defines the total 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 end of the most recently ended fiscal quarter. We were in compliance with these covenants at December 31, 2020.

As of December 31, 2020, we had no borrowings outstanding under our revolving credit facility. We had $0.1 million in letters of credit outstanding under the Credit Agreement at December 31, 2020 and, as a result, had available borrowing capacity of approximately $600 million at that date.

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, 2020, we had $60.7 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 by us 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 or 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, 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. None of our subsidiaries are currently required to guarantee payment under the Credit Agreement.

Series A Senior Notes and Series B 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 bore interest at a rate of 4.97% per annum. On September 25, 2019, we fully prepaid the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bore interest at a rate of 4.27% per annum. On December 16, 2019, we fully prepaid the Series B Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

Primarily as a result of the "make-whole" premiums, we incurred an $8.2 million loss on early extinguishment of the Series A Notes in the three months ended September 30, 2019, and a $15.8 million loss on early extinguishment of the Series B Notes in the three months ended December 31, 2019, which were included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

2028 Senior Notes and 2029 Senior Notes — On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 3.95% Senior Notes due 2028 (the "2028 Notes"). The net proceeds before offering expenses were approximately $521 million, of which we used $239 million to repay amounts outstanding under our revolving credit facility. On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of our 5.15% Senior Notes due 2029 (the "2029 Notes"). The net proceeds before offering expenses were approximately $347 million. We used a portion of the net proceeds from the offering to prepay our Series B Notes. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement in 2019.

During the fourth quarter of 2020, we elected to repurchase portions of our 2028 Notes and 2029 Notes in the open market. The principal amounts retired through these transactions totaled $15.5 million related to our 2028 Notes and $0.8 million related to our 2029 Notes, plus accrued interest. We recorded corresponding gains on the extinguishment of these amounts totaling $3.4 million and $0.2 million, respectively, net of the proportional write-off of associated deferred financing costs and original issuance discounts. These gains are included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

We pay interest on the 2028 Notes on February 1 and August 1 of each year. The 2028 Notes will mature on February 1, 2028. The 2028 Notes bear interest at a rate of 3.95% per annum.

We pay interest on the 2029 Notes on May 15 and November 15 of each year. The 2029 Notes will mature on November 15, 2029. The 2029 Notes bear interest at a rate of 5.15% per annum.

The 2028 Notes and 2029 Notes (together, the "Senior Notes") are our senior unsecured obligations, which rank equally with all of our other existing and future senior unsecured debt and will rank senior in right of payment to all of our other future subordinated debt. The Senior Notes will be effectively subordinated to any of our future secured debt to the extent of the value of the assets securing such debt. In addition, the Senior Notes will be structurally subordinated to the liabilities (including trade payables) of our subsidiaries that do not guarantee the Senior Notes. None of our subsidiaries are currently required to be a guarantor under the Senior Notes. If our subsidiaries guarantee the Senior Notes in the future, such guarantees (the "Guarantees") will rank equally in right of payment with all of the guarantors' future unsecured senior debt and senior in right of payment to all of the guarantors' future subordinated debt. The Guarantees will be effectively subordinated to any of the guarantors' future secured debt to the extent of the value of the assets securing such debt.

At our option, we may redeem the Senior Notes in whole or in part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date, plus a "make-whole" premium. Additionally, commencing on November 1, 2027, in the case of the 2028 Notes, and on August 15, 2029, in the case of the 2029 Notes, at our option, we may redeem the respective Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date.

The indentures pursuant to which the Senior Notes were issued include covenants that, among other things, limit our and our subsidiaries' ability to incur certain liens, engage in sale and lease-back transactions or consolidate, merge, or transfer all or substantially all of their assets. These covenants are subject to important qualifications and limitations set forth in the indentures.

Upon the occurrence of a change of control triggering event, as defined in the indentures, each holder of the Senior Notes may require us to purchase all or a portion of such holder's Senior Notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date.

The indentures also provide for events of default which, if any of them occurs, would permit or require the principal of, premium, if any, and accrued interest, if any, on the Senior Notes to become or to be declared due and payable.

Debt issuance costs — We incurred approximately $0.2 million in debt issuance costs in connection with the Term Loan Agreement. We incurred approximately $4.6 million in debt issuance costs in connection with the Credit Agreement. We also incurred an additional $0.4 million in debt issuance costs in connection with our entry into Amendment No. 2. We incurred approximately $1.9 million in debt issuance costs in connection with the Series A Notes and approximately $1.6 million in debt issuance costs in connection with the Series B Notes. We incurred approximately $1.6 million in debt issuance costs in connection with the 2028 Notes and approximately $1.0 million in debt issuance costs in connection with the 2029 Notes. These costs were deferred and are being recognized as interest expense over the term of the underlying debt. 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 are classified as a deferred charge. Amortization of debt issuance costs is reported as interest expense.

Interest expense related to the amortization of debt issuance costs was approximately $1.1 million, $2.0 million and $2.0 million for the years ended December 31, 2020, 2019 and 2018, respectively. Amortization of debt issuance costs for the year ended December 31, 2020 includes $0.1 million of debt issuance costs that were expensed as a result of the early redemption of a portion of our 2028 Notes and our 2029 Notes as well as the partial repayment of our borrowings under our Term Loan Agreement. Amortization of debt issuance costs for the year ended December 31, 2019 includes $0.2 million of debt issuance costs that were expensed as a result of the Series A Notes prepayment, $0.4 million of debt issuance costs that were expensed as a result of the Series B Notes prepayment and approximately $0.1 million of debt issuance costs that were expensed as a result of the Term Loan Agreement partial repayment. Amortization of debt issuance costs for the year ended December 31, 2018 includes $0.3 million of debt issuance costs related to commitments by lenders under our previous credit agreement who did not participate in the Credit Agreement.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2020 (in thousands):

Year ending December 31,	
2021	$ —
2022	50,000
2023	—
2024	—
2025	—
Thereafter	858,755
Total	$908,755

10. Commitments, Contingencies and Other Matters

Commitments – As of December 31, 2020, we maintained letters of credit in the aggregate amount of $60.8 million primarily 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, 2020, no amounts had been drawn under the letters of credit.

As of December 31, 2020, we had commitments to purchase major equipment totaling approximately $14.7 million for our drilling, pressure pumping, directional drilling and oilfield rentals businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. The agreements expire in years 2021 and 2022. As of December 31, 2020, the remaining obligation under these agreements was approximately $13.4 million, of which approximately $10.0 million and $3.4 million relate to 2021 and 2022, respectively. In the event the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall. In 2017, we entered into a capacity reservation agreement that required a cash deposit to increase our access to finer grades of sand for our pressure pumping business. As market prices for sand substantially decreased since 2017, we purchased lower cost sand outside of this capacity reservation contract and recorded a charge of $9.2 million and $12.7 million in the second quarters of 2020 and 2019, respectively, to revalue the deposit to its expected realizable value. There is no value assigned to the capacity reservation contract subsequent to the charge recorded in the second quarter of 2020.

Contingencies – Our operations are subject to many hazards inherent in the businesses in which it operates, including inclement weather, blowouts, explosions, fires, loss of well control, motor vehicle accidents, equipment failure, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving our employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause us to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to our reputation, loss of customers and an inability to obtain insurance.

We have indemnification agreements with many of our customers, and also maintain liability and other forms of insurance. In general, our 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 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 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 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 equipment and certain other assets, such insurance does not cover the full replacement cost of such 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 $10.0 million per occurrence deductible on our general liability coverage, a $2.0 million per occurrence deductible on our primary automobile liability insurance coverage, and a $5.0 million per occurrence deductible on our excess automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and most cybersecurity risks, and do not carry a significant amount of insurance to cover risks of underground reservoir damage.

We are party to various legal proceedings arising in the normal course of our 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, cash flows or results of operations.

Other Matters — We have a Change in Control Agreement with one of our Executive Vice Presidents (the "Specified Employee"). The Change in Control Agreement generally has an initial term with automatic twelve-month renewals unless we notify 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 occurs during the term of the agreement and the Specified Employee's employment is terminated (i) by us 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 Agreement), 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 prorated for the portion of the fiscal year preceding the termination date);
- a payment equal to 2 times 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 our welfare plans for up to two years.

The 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.

We have Employment Agreements with our Chief Executive Officer, Chief Financial Officer, General Counsel and the President of our 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, we 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 us 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 our decision to terminate 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 us 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 Chief Financial Officer, 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,
- we will accelerate vesting of all options and restricted stock awards on the 60th day following the executive's termination, and
- we will pay the executive certain accrued obligations and certain obligations pursuant to the terms of employee benefit plans.

If our decision to terminate 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 us 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 Chief Financial Officer, General Counsel and President of Patterson-UTI Drilling) of subsidized benefits continuation coverage.

11. Stockholders' Equity

Stockholder Rights Agreement — On April 22, 2020, our Board of Directors adopted a stockholder rights agreement and declared a dividend of one right (a "Right") for each outstanding share of our common stock to stockholders of record at the close of business on May 8, 2020. Each Right entitles its holder, subject to the terms of the Rights Agreement (as defined below), to purchase from us one one-thousandth of a share of our Series A Junior Participating Preferred Stock, par value $0.01 per share, at an exercise price of $17.00 per Right, subject to adjustment. The description and terms of the Rights are set forth in a stockholder rights agreement, dated as of April 22, 2020 (the "Rights Agreement"), between us and Continental Stock Transfer & Trust Company, as rights agent (the "Rights Agent").

Initially, these Rights are not exercisable and trade with our shares of common stock. Under the Rights Agreement, the Rights generally become exercisable only if a person or group of persons acting together (each, an "acquiring person") acquires beneficial ownership of 10% (12% for passive investors, subject to the Excluded Persons exception below) or more of the outstanding shares of our common stock.

In that situation, each holder of a Right (other than the acquiring person, whose Rights will become void) will become entitled to purchase additional shares of our common stock at a 50% discount. In addition, if we are acquired in a merger or other business combination after an unapproved party acquires more than 10% (12% for passive investors, subject to the Excluded Persons exception below) of our outstanding shares of common stock, each holder of a Right would then be entitled to purchase shares of the acquiring company's stock at a 50% discount. Our Board of Directors, at its option, may exchange each Right (other than Rights owned by the acquiring person that have become void) in whole or in part, at an exchange ratio of one share of our common stock per outstanding Right, subject to adjustment. Except as provided in the Rights Agreement, our Board of Directors is entitled to redeem the Rights at $0.001 per Right.

Persons or groups that beneficially own 10% (12% for passive investors, subject to the Excluded Persons exception below) or more of our outstanding common stock prior to our announcement of our adoption of the Rights Agreement will generally not cause the Rights to be exercisable until such time as those persons or groups become the beneficial owner of any additional shares of our common stock, subject to certain exceptions.

On July 22, 2020, we and the Rights Agent entered into an amendment to the Rights Agreement. The amendment revises the definition of "acquiring person" in the Rights Agreement to exclude Excluded Persons. The amendment defines "Excluded Persons" as BlackRock, Inc. (collectively with the investment funds and accounts for which it acts or may act as manager and/or investment advisor, "BlackRock") and The Vanguard Group, Inc. (together with the investment funds and accounts for which it acts or may act as manager and/or investment advisor, "Vanguard"). Our Board of Directors may determine, in its sole discretion, that BlackRock or Vanguard is no longer an "Excluded Person" if any of the representations, warranties, conditions or provisions in letter agreements between us and BlackRock or Vanguard, respectively, are breached or cease to be true, correct and complete in all material respects. Under each letter agreement, BlackRock and Vanguard represent, respectively, among other things, that:

- Such investor will not acquire 20% or more of our then-outstanding common stock;
- No single fund of such investor holds or will hold an economic interest (taking into account the ownership rules of Section 382 of the Internal Revenue Code) of 4.9% or more of our common stock, other than as disclosed to us; and
- Such investor will only acquire beneficial ownership of our common stock in the ordinary course of business and not with the purpose or effect of changing or influencing control of us.

The Rights Agreement will expire on April 21, 2021, but our Board of Directors may consider earlier termination of the Rights Agreement if warranted.

Cash Dividends – We paid cash dividends during the years ended December 31, 2020, 2019 and 2018 as follows:

	Per Share	Total (in thousands)
2020		
Paid on March 19, 2020	$0.04	$ 7,629
Paid on June 18, 2020	0.02	3,735
Paid on September 17, 2020	0.02	3,746
Paid on December 17, 2020	0.02	3,752
Total cash dividends	$0.10	$18,862
2019		
Paid on March 21, 2019	$0.04	$ 8,499
Paid on June 20, 2019	0.04	8,344
Paid on September 19, 2019	0.04	7,847
Paid on December 19, 2019	0.04	7,738
Total cash dividends	$0.16	$32,428
2018		
Paid on March 22, 2018	$0.02	$ 4,443
Paid on June 21, 2018	0.04	8,832
Paid on September 20, 2018	0.04	8,685
Paid on December 20, 2018	0.04	8,629
Total cash dividends	$0.14	$30,589

On February 3, 2021, 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 18, 2021 to holders of record as of March 4, 2021. 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.

Share Repurchases and Acquisitions – On September 6, 2013, our Board of Directors approved a stock buyback program that authorized purchases of up to $200 million of our common stock in open market or privately negotiated transactions. On July 25, 2018, our Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 6, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 24, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. All purchases executed to date have been through open market transactions. Purchases under the program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. There is no expiration date associated with the buyback program. As of December 31, 2020, we had remaining authorization to purchase approximately $130 million of our outstanding common stock under the stock buyback program. Shares of stock purchased under the buyback program are held as treasury shares.

We acquired shares of stock from employees during 2020, 2019, and 2018 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price and employees' tax withholding obligations upon the exercise of stock options. The remainder of these shares were acquired to satisfy payroll withholding obligations upon the settlement of performance unit awards and the vesting of restricted stock and restricted stock units. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Plan (as defined below) and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2020, 2019 and 2018 were as follows (dollars in thousands):

	2020		2019		2018	
	Shares	**Cost**	**Shares**	**Cost**	**Shares**	**Cost**
Treasury shares at beginning of period	77,336,387	$1,345,134	53,701,096	$1,080,448	43,802,611	$ 918,711
Purchases pursuant to stock buyback program	5,826,266	20,000	22,566,331	250,109	9,331,131	150,497
Acquisitions pursuant to long-term incentive plan	239,669	1,179	1,037,947	14,205	567,354	11,240
Other	—	—	31,013	372	—	—
Treasury shares at end of period	83,402,322	$1,366,313	77,336,387	$1,345,134	53,701,096	$1,080,448

12. Stock-based Compensation

We use share-based payments to compensate employees and non-employee directors. We recognize the cost of share-based payments under the fair-value-based method. Share-based awards include equity instruments in the form of stock options, restricted stock or restricted stock units that have included service conditions and, in certain cases, performance conditions. Our share-based awards also include share-settled performance unit awards. Share-settled performance unit awards are accounted for as equity awards. In 2020, we granted performance-based cash-settled phantom units, which are accounted for as a liability classified award. We issue 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 Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") was originally approved by our stockholders effective as of April 17, 2014 and authorized 9.1 million shares for issuance. The Board of Directors adopted a resolution that no future grants would be made under any of our other previously existing plans. On June 29, 2017, our stockholders approved the amendment and restatement of the 2014 Plan (the "Amended and Restated Plan") to increase the number of shares available under the plan by 9.8 million shares. On June 6, 2019, our stockholders approved an amendment to the Amended and Restated Plan to increase the number of shares available for issuance under the plan by 9.5 million shares and to extend the latest date on which awards may be granted under the Amended and Restated Plan to June 6, 2029 (the "Amendment" and the Amended and Restated Plan, as amended by the Amendment, the "Plan"). The aggregate number of shares of our common stock authorized for grant under the Plan is 28.4 million.

Our share-based compensation plans at December 31, 2020 are as follows:

Plan Name	Shares Authorized for Grant	Shares Underlying Awards Outstanding	Shares Available for Grant
Amended and Restated Plan	28,400,000	6,634,513	4,986,392
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	—	1,793,500	—

A summary of the 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 our 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, 2020, non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the Plan.

Options granted under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive 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.

Stock Options — We estimate the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of our common stock over the most recent period equal to the expected term of the options as of the date such options are granted. The expected term assumptions are based on our 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. No options were granted during the years ended December 31, 2020, 2019 and 2018.

Stock option activity for the year ended December 31, 2020 follows:

	Shares	Weighted Average Exercise Price Per Share
Outstanding at beginning of year	4,766,150	$20.62
Exercised	—	$ —
Expired	(740,000)	$15.10
Outstanding at end of year	4,026,150	$21.63
Exercisable at end of year	4,011,150	$21.64

Options outstanding at December 31, 2020 have no intrinsic value and a weighted-average remaining contractual term of 3.22 years. Options exercisable at December 31, 2020 have no intrinsic value and a weighted-average remaining contractual term of 3.21 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2020, 2019 and 2018 follows (in thousands, except per share data):

	2020	2019	2018
Weighted-average grant date fair value of stock options granted (per share)	NA	NA	NA
Aggregate grant date fair value of stock options vested during the year	$ 89	$543	$1,954
Aggregate intrinsic value of stock options exercised	$ —	$ —	$ —

As of December 31, 2020, options to purchase 15,000 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2020 with respect to these non-vested options follows (dollars in thousands):

Aggregate intrinsic value	$ —
Weighted-average remaining contractual term	5.71 years
Weighted-average remaining expected term	0.71 years
Weighted-average remaining vesting period	0.71 years
Unrecognized compensation cost	$ 63

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

Restricted stock activity for the year ended December 31, 2020 follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested restricted stock outstanding at beginning of year	72,051	$21.59
Vested	(72,051)	$21.59
Forfeited	—	$ —
Non-vested restricted stock outstanding at end of year	—	$ —

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 and, in certain cases, performance conditions. Forfeitable dividend equivalents are accrued on certain restricted stock units that will be paid upon vesting. We use the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock unit activity for the year ended December 31, 2020 follows:

	Time Based	Performance Based	Weighted Average Grant Date Fair Value Per Share
Non-vested restricted stock units outstanding at beginning of year	2,631,726	397,315	$15.81
Granted	1,691,246	—	$ 4.25
Vested [(1)]	(1,285,658)	(38,000)	$16.32
Forfeited	(295,766)	—	$13.39
Non-vested restricted stock units outstanding at end of year	2,741,548	359,315	$ 9.52

(1) All of the performance-based restricted stock units that vested during 2020 were granted in 2017.

As of December 31, 2020, approximately 3.0 million non-vested restricted stock units outstanding are expected to vest. Additional information as of December 31, 2020 with respect to these non-vested restricted stock units follows (dollars in thousands):

Aggregate intrinsic value	$ 15,977
Weighted-average remaining vesting period	1.76 years
Unrecognized compensation cost	$ 20,623

Performance Unit Awards — We have granted share-settled performance unit awards to certain employees (the "Performance Units") on an annual basis since 2010. The Performance Units provide for the recipients to receive a grant of shares of common 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 2017 the three-year performance period commenced on May 1.

The performance goals for the Performance Units are tied to our 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. For the Performance Units granted in April 2018, the recipients will receive a target number of shares if our total shareholder return during the performance period, when compared to the peer group, is at the 50th percentile. For the Performance Units granted in April 2019 and April 2020, the recipients will receive the target number of shares if our total shareholder return during the performance period, when compared to the peer group, is at the 55th percentile. If our total shareholder return during the performance period, when compared to the peer group, is at the 75th percentile or higher, then the recipients will receive two times the target number of shares. If our total shareholder return during the performance period, when compared to the peer group, is at the 25th percentile, then the recipients will only receive one-half of the target number of shares. If our total shareholder return during the performance period, when compared to the peer group, is between the 25th and target percentile, or the target and 75th percentile, then the shares to be received by the recipients will be determined using linear interpolation for levels of achievement between these points.

For the Performance Units granted in April 2018, the payout is based on relative performance and does not have an absolute performance requirement. For the Performance Units granted in April 2019 and April 2020, the payout shall not exceed the target number of shares if our total shareholder return is negative or zero. Additionally, the Performance Units granted in April 2020 will not pay out if our total shareholder return is not equal to or greater than the total stockholder return of the S&P 500 Index for the Performance Period.

The total target number of shares with respect to the Performance Units for the years 2015-2020 is set forth below:

	2020 Performance Unit Awards	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards
Target number of shares	500,500	489,800	310,700	186,198	185,000	190,600

In April 2018, 381,200 shares were issued to settle the 2015 Performance Units. In April 2019, 185,000 shares were issued to settle the 2016 Performance Units. In May 2020, 332,773 shares were issued to settle the 2017 Performance Units. The Performance Units granted in 2018, 2019, and 2020 have not reached the end of their respective performance periods.

Because the Performance Units are share-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):

	2020 Performance Unit Awards	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards
Aggregate fair value at date of grant	$826	$9,958	$8,004	$5,780	$3,854	$4,052

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):

	2020 Performance Unit Awards	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards
Year ended December 31, 2020	$206	$3,319	$2,668	$ 642	NA	NA
Year ended December 31, 2019	NA	$2,489	$2,668	$1,927	$ 321	NA
Year ended December 31, 2018	NA	NA	$2,001	$1,927	$1,285	$338

Dividends on Equity Awards – Non-forfeitable cash dividends are paid on restricted stock awards and dividend equivalents are paid or accrued on certain restricted stock units. These dividends 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 reductions of retained earnings for the portion of restricted stock units expected to vest.
- Dividend equivalents are recognized as additional compensation cost for the portion of restricted stock units that are not expected to vest or that ultimately do not vest.

Phantom Units — In May 2020, the Compensation Committee approved a grant of long-term performance-based phantom units to our Chief Executive Officer and President, William A. Hendricks, Jr (the "Phantom Units"). The Phantom Units were granted outside of the 2014 Plan. Pursuant to this phantom unit grant, Mr. Hendricks may earn from 0% to 200% of a target award of 298,500 phantom units based on our achievement of the same performance conditions over the same Performance Period that applies to the Performance Units granted in April 2020, as described above. Earned Phantom Units, if any, will be settled in 2023, following completion of the three-year Performance Period, in a cash payment equal to the number of earned phantom units multiplied by our average trading price per share over the twenty consecutive trading days ending March 31, 2023. Because the Phantom Units are cash-settled awards, they are accounted for as a liability classified award. The grant date fair value of the Phantom Units was $1.2 million. Compensation expense is recognized on a straight-line basis over the performance period, with the amount recognized fluctuating as a result of the Phantom Units being remeasured to fair value at the end of each reporting period due to their liability-award classification. We recognized $0.6 million compensation expense associated with the Phantom Units in 2020.

13. Leases

ASC Topic 842 Leases

On January 1, 2019, we adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. We have elected to report all leases at the beginning of the period of adoption and not restate our comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained.

We have entered into operating leases for operating locations, corporate offices and certain operating equipment. These leases have remaining lease terms of six months to eight years as of December 31, 2020. Currently, we do not have any finance leases. Renewal options are included in the right-of-use asset and lease liability if it is reasonably certain that we will exercise the option, and termination options are included in the right-of-use asset and lease liability if it is not reasonably certain we will exercise the option. We have elected the short-term lease recognition practical expedient whereby right of use assets and lease liabilities are not recognized for leasing arrangements with an initial term of one year or less.

Topic 842 requires that lessees and lessors discount lease payments at the lease commencement date using the rate implicit in the lease, if available, or the lessee's incremental borrowing rate. We use the implicit rate when readily determinable. If the implicit rate is not readily determinable, we use our incremental borrowing rate based on the information available at the commencement date in the determination of the present value of future lease payments.

In the fourth quarter of 2019, we had entered into a sale-leaseback transaction that qualified as a sale. We sold a facility for proceeds of $10.2 million and concurrently entered into an operating lease agreement with the unrelated third-party for certain floors of the building for a 58-month term. The associated gain on sale of approximately $0.8 million was included in "Other operating expenses (income), net" in the consolidated statements of operations.

For the year ended December 31, 2020, we entered into two new facility leases and recorded an increase to the operating lease right-of-use assets and corresponding operating lease liabilities of approximately $1.5 million. We also extended two facilities leases and recorded an increase to the operating lease right-of-use assets and corresponding operating lease liabilities of approximately $0.2 million. We terminated four facility leases and three operating equipment leases and recorded a decrease to the operating lease right-of-use assets of approximately $0.4 million and corresponding lease liabilities of approximately $2.2 million. The right-of-use assets that were formally terminated were partially impaired in the second quarter of 2020 in conjunction with our restructuring plan. See Note 20 for additional information on our restructuring expenses.

Practical Expedients Adopted with Topic 842

We have elected to adopt the following practical expedients upon the transition date to Topic 842 on January 1, 2019:

- Transitional practical expedients package: An entity may elect to apply the listed practical expedients as a package to all the leases that commenced before the effective date. The practical expedients are:

  a) The entity need not reassess whether any expired or existing contracts are or contain leases;
  b) The entity need not reassess the lease classification for expired or existing contracts;
  c) The entity need not reassess initial direct costs for any existing leases.

- Use of portfolio approach: An entity can apply this guidance to a portfolio of leases with similar characteristics if the entity reasonably expects that the application of the leases model to the portfolio would not differ materially from the application of the lease model to the individual leases in that portfolio. This approach can also be applied to other aspects of the leases guidance for which lessees/ lessors need to make judgments and estimates, such as determining the discount rate and determining and reassessing the lease term.

- Lease and non-lease components: As a practical expedient, lease and non-lease components may be combined where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. Our contract drilling, pressure pumping and directional drilling contracts contain a lease component related to the underlying equipment utilized, in addition to the service component provided by our crews and expertise to operate the related equipment. We have concluded that the non-lease service of operating our equipment and providing expertise in the services provided to customers is predominant in our drilling, pressure pumping and directional drilling contracts. With the election of this practical expedient, we will continue to present a single performance obligation for these contracts under the revenue guidance in ASC 606.

Lease expense consisted of the following for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Operating lease cost	$6,911	$10,944
Short-term lease expense [(1)]	2	440
Total lease expense	$6,913	$11,384

[(1)] Short-term lease expense represents expense related to leases with a contract term of one year or less.

Supplemental cash flow information related to leases for the years ended December 31, 2020 and 2019 is as follows (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$11,576	$10,033
Right of use assets obtained in exchange for lease obligations:		
Operating leases	$ 1,763	$10,870

Supplemental balance sheet information related to leases as of December 31, 2020 and 2019 is as follows:

	December 31, 2020	December 31, 2019
Weighted Average Remaining Lease Term:		
Operating leases	5.2 years	5.3 years
Weighted Average Discount Rate:		
Operating leases	4.1%	4.2%

Maturities of operating lease liabilities as of December 31, 2020 are as follows (in thousands):

Year ending December 31,	
2021	$ 8,011
2022	6,206
2023	4,030
2024	3,128
2025	2,109
Thereafter	5,641
Total lease payments	29,125
Less imputed interest	(2,911)
Total	$26,214

14. Income Taxes

Loss before income taxes for the U.S. for years ended December 31, 2020, 2019 and 2018 are $917 million, $500 million, and $343 million, respectively. Loss before income taxes for non-U.S. jurisdictions for years ended December 31, 2020, 2019 and 2018 are $14.2 million, $30.5 million, and $24.3 million, respectively.

Components of the income tax provision applicable to federal, state and foreign income taxes for the years ended December 31, 2020, 2019 and 2018 are as follows (in thousands):

	2020	2019	2018
Federal income tax benefit:			
Current	$ (1,977)	$ (1,976)	$ (3,954)
Deferred	(107,334)	(90,441)	(35,081)
	(109,311)	(92,417)	(39,035)
State income tax expense (benefit):			
Current	225	851	1,704
Deferred	(17,949)	(11,593)	(11,147)
	(17,724)	(10,742)	(9,443)
Foreign income tax expense (benefit):			
Current	(291)	(348)	(2,552)
Deferred	—	(1,168)	5,043
	(291)	(1,516)	2,491
Total income tax benefit:			
Current	(2,043)	(1,473)	(4,802)
Deferred	(125,283)	(103,202)	(41,185)
Total income tax benefit:	$(127,326)	$(104,675)	$(45,987)

The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2020, 2019 and 2018 is summarized as follows:

	2020	2019	2018
Statutory tax rate	21.0%	21.0%	21.0%
State income taxes - net of the federal income tax benefit	1.7	1.4	1.1
Goodwill impairment	(8.2)	(0.7)	(6.9)
Permanent differences	(0.6)	(1.2)	(0.7)
Tax effects of tax reform	—	—	(1.3)
Valuation allowance	(0.2)	(0.8)	(3.7)
State deferred tax remeasurement	—	(1.1)	2.3
Other differences, net	—	1.1	0.7
Effective tax rate	13.7%	19.7%	12.5%

The effective tax rate decreased by approximately 6.0% to 13.7% for 2020 compared to 19.7% for 2019. This difference was primarily due to higher goodwill impairment charges in 2020 relative to 2019, which are not deductible for tax purposes. These charges resulted in a 8.2% decrease to the effective tax rate in 2020, as compared to a 0.7% decrease to the effective tax rate in 2019.

The tax effect of temporary differences and tax attributes representing deferred tax assets and liabilities at December 31, 2020 and 2019 are as follows (in thousands):

	2020	2019
Deferred tax assets:		
Net operating loss carryforwards	$ 370,875	$ 375,308
Tax credits	4,918	4,138
Expense associated with stock-based compensation	11,252	10,561
Workers' compensation allowance	17,177	19,536
Other deferred tax asset	24,735	21,698
	428,957	431,241
Less:		
Valuation allowance	(19,133)	(17,231)
Total deferred tax assets	409,824	414,010
Deferred tax liabilities:		
Property and equipment basis difference	(475,025)	(607,785)
Other	(12,475)	(9,184)
Total deferred tax liabilities	(487,500)	(616,969)
Net deferred tax liability	$ (77,676)	$(202,959)

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 when necessary valuation 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. We assess the realizability of our deferred tax assets quarterly and consider carryback availability, the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. In 2020, we recorded an additional $1.9 million of valuation allowances against our net deferred tax assets, primarily relating to certain Canadian subsidiaries.

For income tax purposes, we have approximately $1.4 billion of gross federal net operating losses, approximately $49.4 million of gross Canadian net operating losses and approximately $931 million of post-apportionment state net operating losses as of December 31, 2020, before valuation allowances. The majority of federal net operating losses will expire in varying amounts, if unused, between 2034 and 2037. Federal net operating losses generated in 2018, 2019 and 2020 can be carried forward indefinitely. Canadian net operating losses will expire in varying amounts, if unused, between 2036 and 2040. State net operating losses will expire in varying amounts, if unused, between 2023 and 2040.

As of December 31, 2020, we had no unrecognized tax benefits. We have established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2020, the tax years ended December 31, 2014 through December 31, 2019 are open for examination by U.S. taxing authorities. As of December 31, 2020, the tax years ended December 31, 2013 through December 31, 2019 are open for examination by Canadian taxing authorities.

We continue to monitor income tax developments in the United States and other countries where we have legal entities. During 2020, the United States enacted various legislation related to COVID-19 relief, which includes multiple tax provisions. We have considered these tax provisions and do not currently expect any material impact to our financial statements. We will incorporate into our future financial statements the impacts, if any, of future regulations and additional authoritative guidance when finalized.

We continue to elect permanent reinvestment of unremitted earnings in Canada effective January 1, 2010, and we intend to do so for the foreseeable future. If we were to repatriate earnings, in the form of dividends or otherwise, we may be subject to certain income and/or withholding taxes (subject to an adjustment for foreign tax credits).

15. Earnings Per Share

We provide a dual presentation of our net loss per common share in our consolidated statements of operations: basic net loss per common share (“Basic EPS”) and diluted net 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, performance units and restricted stock units. The dilutive effect of stock options, performance units 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 loss per share for the years ended December 31, 2020, 2019 and 2018, 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):

	2020	2019	2018
BASIC EPS:			
Net loss attributed to common stockholders	$(803,692)	$(425,703)	$(321,421)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	188,013	203,039	218,643
Basic net loss per common share	$ (4.27)	$ (2.10)	$ (1.47)
DILUTED EPS:			
Net loss attributed to common stockholders	$(803,692)	$(425,703)	$(321,421)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	188,013	203,039	218,643
Add dilutive effect of potential common shares	—	—	—
Weighted average number of diluted common shares outstanding	188,013	203,039	218,643
Diluted net loss per common share	$ (4.27)	$ (2.10)	$ (1.47)
Potentially dilutive securities excluded as anti-dilutive	8,747	9,195	9,762

16. Employee Benefits

We maintain a 401(k) plan for all eligible employees. Our operating results include expenses of approximately $7.7 million in 2020, $13.2 million in 2019 and $14.3 million in 2018 for our contributions to the plan.

17. Business Segments

At December 31, 2020, we had three reportable business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) directional drilling services. Each of these segments represents a distinct type of business and has a separate management team that reports to our 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 — We market our contract drilling services to major and independent oil and natural gas operators. As of December 31, 2020, we had 210 marketed land-based drilling rigs in the continental United States.

Given our longer-term outlook for the western Canadian market, we elected to close our Canadian drilling operations during the second quarter of 2020. As a result, we recognized an impairment charge of $8.3 million related to the closure. For the years ended December 31, 2020, 2019 and, 2018, contract drilling revenue earned in Canada was $1.0 million, $4.7 million and $9.3 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totaled $8.2 million and $20.1 million as of December 31, 2020 and 2019, respectively.

Pressure Pumping — We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian region. Substantially all of the revenue in the pressure pumping segment is from well stimulation services (such as hydraulic fracturing) 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. We also provide cementing services through our pressure pumping segment. Cementing is the process of inserting material between the wall of the well bore and the casing to support and stabilize the casing.

Directional Drilling — We provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States. Substantially all of the revenue in the directional drilling segment is from directional drilling, downhole performance motors and measurement-while-drilling services, which are sold as a bundle.

Major Customer — During 2020, 2019 and 2018, no single customer accounted for more than 10% of our consolidated operating revenues.

The following tables summarize selected financial information relating to our business segments (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Revenues:			
Contract drilling	$ 670,357	$1,309,988	$1,432,012
Pressure pumping	336,111	868,694	1,573,396
Directional drilling	73,356	188,786	209,275
Other operations [(1)]	57,962	122,885	131,028
Elimination of intercompany revenues - Contract drilling [(2)]	(1,231)	(1,638)	(1,520)
Elimination of intercompany revenues - Other operations [(2)]	(12,306)	(18,030)	(17,194)
Total revenues	$1,124,249	$2,470,685	$3,326,997
Income (loss) before income taxes:			
Contract drilling	$ (543,438)	$ (151,329)	$ (33,115)
Pressure pumping	(166,666)	(102,701)	(77,328)
Directional drilling	(40,612)	(52,724)	(117,497)
Other operations	(41,685)	(54,725)	(18,221)
Corporate	(94,251)	(94,414)	(76,016)
Credit loss expense	(5,606)	(5,683)	—
Interest income	1,254	6,013	5,597
Interest expense	(40,770)	(75,204)	(51,578)
Other	756	389	750
Loss before income taxes	$ (931,018)	$ (530,378)	$ (367,408)
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 433,771	$ 668,007	$ 571,607
Pressure pumping	152,630	233,952	250,010
Directional drilling	36,504	52,223	45,317
Other operations	41,511	42,803	41,512
Corporate	6,494	6,888	7,872
Total depreciation, depletion, amortization and impairment	$ 670,910	$1,003,873	$ 916,318
Capital expenditures:			
Contract drilling	$ 105,037	$ 194,416	$ 394,595
Pressure pumping	21,678	105,803	173,848
Directional drilling	4,681	15,549	35,929
Other operations	12,378	27,132	34,660
Corporate	1,707	4,612	2,426
Total capital expenditures	$ 145,481	$ 347,512	$ 641,458

Identifiable assets:			
Contract drilling	$2,315,318	$3,190,463	$3,817,638
Pressure pumping	486,702	695,570	921,237
Directional drilling	107,807	164,273	239,341
Other operations	88,676	128,290	177,374
Corporate [3]	300,566	261,019	314,276
Total assets	$3,299,069	$4,439,615	$5,469,866

(1) Other operations includes our oilfield rentals business, drilling equipment service business, the electrical controls and automation business and the oil and natural gas working interests.

(2) Intercompany revenues consist of revenues from contract drilling for services provided to our other operations, and revenues from other operations for services provided to contract drilling, pressure pumping and within other operations. These revenues are generally based on estimated external selling prices and are eliminated during consolidation.

(3) Corporate assets primarily include cash on hand and certain property and equipment.

18. Concentrations of Credit Risk

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

We believe we have placed our demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2020 and 2019, our demand deposits and temporary cash investments consisted of the following (in thousands):

	2020	2019
Deposits in FDIC and SIPC-insured institutions under insurance limits	$ 1,000	$ 1,250
Deposits in FDIC and SIPC-insured institutions over insurance limits	227,961	179,375
Deposits in foreign banks	1,966	2,309
	230,927	182,934
Less outstanding checks and other reconciling items	(6,012)	(8,749)
Cash and cash equivalents	$224,915	$174,185

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 we provide services. As is general industry practice, we typically do not require customers to provide collateral. A $5.6 million and $5.7 million provision for credit loss was recognized in 2020 and 2019, respectively, in relation to accounts receivable balances that were estimated to be uncollectible. No credit loss expense was recognized in 2018.

19. 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 our outstanding debt balances as of December 31, 2020 and 2019 is set forth below (in thousands):

	December 31, 2020		December 31, 2019	
	Carrying Value	Fair Value	Carrying Value	Fair Value
3.95% Senior Notes	$509,505	$471,019	$525,000	$511,485
5.15% Senior Notes	349,250	319,560	350,000	358,864
Term Loan Agreement	50,000	50,000	100,000	100,000
Total debt	$908,755	$840,579	$975,000	$970,349

The fair values of the 3.95% Senior Notes at December 31, 2020 and December 31, 2019 are based on discounted cash flows associated with the notes using the 5.24% market rate of interest at December 31, 2020 and the 4.33% market rate of interest at December 31, 2019. The fair values of the 5.15% Senior Notes at December 31, 2020 and December 31, 2019 are based on discounted cash flows associated with the notes using the 6.42% market rate of interest at December 31, 2020 and the 4.81% market rate of interest at December 31, 2019. The fair value estimates of the 3.95% Senior Notes and the 5.15% Senior Notes are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting. The carrying value of the balance outstanding at December 31, 2020 under the Term Loan Agreement approximated its fair value as the instrument has a floating interest rate.

20. Restructuring Expenses

During the second quarter of 2020, we implemented a restructuring plan to improve operating margins, achieve operational efficiencies and reduce indirect support costs. The restructuring included workforce reductions, changes to management structure and facility consolidations and closures. We recorded $38.3 million of charges associated with this plan in the second quarter of 2020. There were no restructuring charges in the comparable periods of 2019 and 2018. We completed the restructuring plan during the third quarter of 2020 and did not incur additional expenses related to the plan.

Contract termination costs relate primarily to agreements to purchase minimum quantities of proppants (sand) from certain vendors. These costs are primarily comprised of a $5.3 million negotiated settlement and termination of an existing contract to purchase minimum quantities of sand and $14.0 million of contractual future payments under two existing contracts to purchase minimum quantities of sand without future economic benefit to us. We will not receive any sand under these contracts. Other exit costs relate primarily to facility closure costs and moving expenses.

The right of use ("ROU") asset abandonments relate to facility and equipment ROU assets abandoned as a result of restructuring.

The following table presents restructuring expenses by reportable segment for the year ended December 31, 2020 (in thousands):

	Contract Drilling	Pressure Pumping	Directional Drilling	Other Operations	Corporate	Total
Severance costs	$1,821	$ 3,460	$ 503	$501	$215	$ 6,500
Contract termination costs	—	20,373	—	—	—	20,373
Other exit costs	523	194	827	—	—	1,544
Right-of-use asset abandonments	86	7,304	1,845	—	686	9,921
Total	$2,430	$31,331	$3,175	$501	$901	$38,338

The following table presents the consolidated balance sheet captions that restructuring accruals are included in as of December 31, 2020 (in thousands):

	December 31, 2020
Accrued liabilities	$14,310
Other long-term liabilities	200
Total	$14,510

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2020				
Operating revenues	$ 445,927	$ 250,380	$ 207,141	$ 220,801
Operating loss	(494,410)	(159,084)	(114,566)	(124,198)
Net loss	(434,722)	(150,332)	(112,111)	(106,527)
Net loss per common share:				
Basic	$ (2.28)	$ (0.81)	$ (0.60)	$ (0.57)
Diluted	$ (2.28)	$ (0.81)	$ (0.60)	$ (0.57)
Included within net loss:				
Goodwill impairment, after tax	$ 340,147	$ —	$ —	$ —
Restructuring, after tax	—	33,967	—	—
Oil and natural gas assets impairment, after tax	9,084	604	—	—
Impairment of property and equipment related to Canadian drilling operations, after tax (1)	—	7,314	—	—
Net gain from the realization of insurance proceeds, after tax (2)	—	(3,696)	—	—
Impairment of capacity reservation contract, after tax (3)	—	8,157	—	—
Gain on early debt extinguishment, after tax (4)	—	—	—	(2,916)

(1) Impairment of property and equipment related to Canadian drilling operations was included in "Depreciation, depletion, amortization and impairment" in the consolidated statements of operations.

(2) Net gain from the realization of insurance proceeds was included in "Other operating expenses (income), net" in the consolidated statements of operations.

(3) Impairment of capacity reservation contract was included in "Other operating expenses (income), net" in the consolidated statements of operations.

(4) Gain on early debt extinguishment was included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2019				
Operating revenues	$704,171	$675,765	$ 598,452	$492,297
Operating loss	(23,383)	(48,125)	(307,305)	(82,763)
Net loss	(28,614)	(49,447)	(261,719)	(85,923)
Net loss per common share:				
Basic	$ (0.14)	$ (0.24)	$ (1.31)	$ (0.44)
Diluted	$ (0.14)	$ (0.24)	$ (1.31)	$ (0.44)
Included within net loss:				
Goodwill impairment, after tax	$ —	$ —	$ 14,276	$ —
Impairment of capacity reservation contract, after tax (1)	—	10,519	—	—
Impairment of property and equipment, after tax (2)	—	—	162,581	—
Directional drilling charges (3)	—	—	13,616	—
Oilfield technology and manufacturing charges, after tax (4)	—	—	11,694	—
Early repayment of debt charge, after tax (5)	—	—	6,614	12,401

(1) Impairment of capacity reservation contract was included in “Other operating expenses (income), net” in the consolidated statements of operations.

(2) Impairment of property and equipment was included in “Depreciation, depletion, amortization and impairment” in the consolidated statements of operations.

(3) Directional drilling charges were included in “Direct operating costs” in the consolidated statements of operations.

(4) Inventory write-offs and severance expense as a result of transitioning away from our engineering and manufacturing efforts in Calgary were included in “Direct operating costs” and “Selling, general and administrative” in the consolidated statements of operations, respectively.

(5) Early repayment of debt charge was included in “Interest expense, net of amount capitalized” in the consolidated statements of operations.

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, 2020				
Deducted from asset accounts:				
Allowance for credit losses	$6,516	$5,606	$(1,280)	$10,842
Year Ended December 31, 2019				
Deducted from asset accounts:				
Allowance for credit losses	$2,312	$5,683	$(1,479)	$ 6,516
Year Ended December 31, 2018				
Deducted from asset accounts:				
Allowance for credit losses	$2,323	$ —	$ (11)	$ 2,312

(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 9, 2021

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 9, 2021.

Signature	Title
/s/ Curtis W. Huff Curtis W. Huff	Chairman of the Board
/s/ William Andrew Hendricks, Jr. William Andrew Hendricks, Jr. *(Principal Executive Officer)*	President, Chief Executive Officer and Director
/s/ C. Andrew Smith C. Andrew Smith *(Principal Financial and Accounting Officer)*	Executive Vice President and Chief Financial Officer
/s/ Tiffany Thom Cepak Tiffany Thom Cepak	Director
/s/ Michael W. Conlon Michael W. Conlon	Director
/s/ Terry H. Hunt Terry H. Hunt	Director
/s/ Janeen S. Judah Janeen S. Judah	Director