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

FORM 10-K

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

For the fiscal year ended December 31, 2018
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 001-36590

INDEPENDENCE CONTRACT DRILLING, INC.

(Exact name of registrant as specified in its charter)

Delaware	**37-1653648**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
20475 State Highway 249, Suite 300	
Houston, Texas	**77070**
(Address of principal executive offices)	*(Zip code)*

(281) 598-1230
(Registrant's telephone number, including area code)

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

Title of Class	Name of each exchange on which registered
Common Stock, $0.01 par value per share	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

Large accelerated filer	☐	Accelerated filer	☑
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	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. Yes ☑ No ☐

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

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant was approximately $105,951,416 as of June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter (based on a closing price of $4.12 per share as reported on the New York Stock Exchange and 25,716,363 shares held by non-affiliates).

There were 77,078,252 shares of the registrant's common stock outstanding as of February 25, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2019 Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) are incorporated by reference into Part III of this Annual Report on Form 10-K.

INDEPENDENCE CONTRACT DRILLING, INC.
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report on Form 10-K, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "plan," "goal," "will" or other words that convey the uncertainty of future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. These risks, contingencies and uncertainties include, but are not limited to, the following:

- a decline in or substantial volatility of crude oil and natural gas commodity prices;
- a sustained decrease in domestic spending by the oil and natural gas exploration and production industry;
- our inability to implement our business and growth strategy, including plans to upgrade and convert SCR rigs acquired in the Sidewinder Drilling LLC combination;
- fluctuation of our operating results and volatility of our industry;
- inability to maintain or increase pricing of our contract drilling services, or early termination of any term contract for which early termination compensation is not paid;
- our backlog of term contracts declining rapidly;
- the loss of any of our customers, financial distress or management changes of potential customers or failure to obtain contract renewals and additional customer contracts for our drilling services;
- overcapacity and competition in our industry;
- an increase in interest rates and deterioration in the credit markets;
- our inability to comply with the financial and other covenants in debt agreements that we may enter into as a result of reduced revenues and financial performance;
- unanticipated costs, delays and other difficulties in executing our long-term growth strategy;
- the loss of key management personnel;
- new technology that may cause our drilling methods or equipment to become less competitive;
- labor costs or shortages of skilled workers;
- the loss of or interruption in operations of one or more key vendors;
- the effect of operating hazards and severe weather on our rigs, facilities, business, operations and financial results, and limitations on our insurance coverage;
- increased regulation of drilling in unconventional formations;
- the incurrence of significant costs and liabilities in the future resulting from our failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment; and
- the potential failure by us to establish and maintain effective internal control over financial reporting.

All forward-looking statements are necessarily only estimates of future results, and there can be no assurance that actual results will not differ materially from expectations, and, therefore, you are cautioned not to place undue reliance on such statements. Any forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this Annual Report on Form 10-K, including those described in (1) Part I, "Item 1A. Risk Factors" and (2) Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." Further, any forward-looking statement speaks only as of the date on which it is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events.

PART I

ITEM 1. *BUSINESS*

Overview

Except as expressly stated or the context otherwise requires, the terms "we," "us," "our," the "Company" and "ICD" refer to Independence Contract Drilling, Inc.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We own and operate a premium fleet comprised of modern, technologically advanced drilling rigs. Our fleet currently includes 32 marketed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and gas properties, and two idle ShaleDriller rigs that will enter our marketed fleet when planned upgrades are completed.

Our marketed 32 rig fleet includes 29 AC powered ("AC") rigs and three 1500-HP ultra-modern SCR rigs. We plan to convert these three SCR rigs to AC pad-optimal status over the next twelve to 18 months based upon market conditions and customer requirements and the timing of their existing contractual commitments. Our two idle rigs that currently are not included in our marketed fleet include one non-walking 1500-HP AC rig and one 1500-HP SCR that will be converted to AC pad-optimal status prior to entering our fleet. We expect both of these rigs to enter our marketed fleet following their upgrade over the next twelve to 18 months based upon market conditions and customer requirements.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas and Midland, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin and the Haynesville Shale; however, our rigs have previously operated in the Eagle Ford Shale and the Mid-Continent and Eaglebine regions as well.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is historically cyclical and characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Our principal executive offices are located at 20475 Hwy 249, Houston, Texas 77070. Our common stock is traded on the NYSE under the symbol "ICD."

Industry Trends

Land Rig Replacement Cycle

The increase in horizontal drilling in the United States over the past fifteen years has resulted in an ongoing land-rig replacement cycle in which the contract drilling industry is systematically upgrading its legacy fleets of electrical silicon-controlled rectifier ("SCR") rigs and mechanical rigs with modern AC rigs that are specifically designed to optimize this type of drilling activity. Additionally, a growing focus on horizontal drilling of longer-reach lateral wells from multi-well pads is driving a further delineation in the United States land rig fleet between pad-optimal rigs specifically designed and engineered for such applications and AC and legacy rigs not specifically engineered for such applications.

The following describes the three different types of rig drives:

Mechanical Rigs. Mechanical rigs were not designed and are not well suited for the demanding requirements of drilling horizontal wells. A mechanical rig powers its systems through a combination of belts, chains and transmissions. This arrangement requires the rig to be rigged up with precise alignment of the belts and chains, which requires substantial time during a rig move. In addition, mechanical power loading of key rig systems, including drawworks, pumps and rotating equipment results in very imprecise control of system parameters, causing lower drill bit life, lower rate of penetration and difficulty maintaining wellbore trajectory.

SCR Rigs. In contrast to mechanical rigs, SCR rigs rely on direct current, or DC, to power the key rig systems. Load is changed by adjusting the amperage supplied to electric motors powering key rig systems. While a substantial improvement over mechanical belts and chains, SCR control is imprecise, and DC power levels normally drift resulting in fluctuations in pump speed and pressure, bit rotation speed, and weight on bit. These fluctuations can cause wellbore deviation, shorter bit life and less optimal rates of penetration. In addition, SCR equipment is heavy and energy inefficient.

AC Rigs. Compared to SCR and mechanical rigs, AC rigs are ideally suited for drilling horizontal wells. The first AC rigs were introduced into the United States land market in the early 2000s, and since that time their use has grown significantly as the use of horizontal drilling has increased. AC rigs use a computer-controlled variable frequency drive ("VFD") to precisely adjust key rig operating parameters and systems allowing for optimization of the rate of penetration, extended bit life and improved control of wellbore trajectory. These factors reduce the amount of time a wellbore is “open hole,” or uncased. Shorter open hole times dramatically reduce adjacent formation damage that can be caused by shale hydration or drilling fluid invasion and enhance the operator’s ability to optimally run and cement casing to complete the drilled well. In addition, when compared to SCR and mechanical rigs, AC rigs are electrically more efficient, produce more torque, utilize regenerative braking, and have digital controls. AC motors are also smaller, lighter and require less maintenance than DC motors.

Shift to Manufacturing Wellbore Model

As a result of significant investments made in unconventional resource plays, exploration and production ("E&P") companies are now focused on developing these investments in a systematic manner. Efficient development of these resource plays involves drilling programs requiring large numbers of wells to be drilled in succession, as opposed to a single or a few wells designed to delineate a field or hold a lease. We view this as analogous to a manufacturing process that requires an engineered program and is focused on economies of scale to reduce overall field development costs. Cost effective development drilling requires more complex well designs, shorter cycle times, and the use of innovative technology in order to reduce an E&P company’s overall field development costs.

One method in which an E&P operator may reduce overall field development costs is through the use of a multi-well pad development program. Pad drilling involves the drilling of multiple wells from a single location, which provides benefits to the E&P company in the form of per well cost savings and accelerated cash flows as compared to non-pad developments. These cost savings result from reduced time required to move the rig between wells, centralized hydraulic fracturing operations and the efficient installation of central production facilities and pipelines. In addition, by performing drilling operations on one well with simultaneous completion operations on a second well, operators do not have to wait until the entire pad is complete to begin earning a return on their investment. Pad drilling promotes “manufacturing” efficiencies by enabling “batch” drilling, whereby an operator drills all of the wells’ surface holes as the first batch, then drills all of the intermediate sections as the second batch, and concludes with the drilling of all of the laterals as the final batch. Efficiencies are created because hole sizes change less frequently, and operators use the same mud system and tools repeatedly. We believe as operators have shifted over time to horizontal drilling, they have implemented pad drilling in order to maximize economics and optimize development plans. In order to maximize the efficiencies gained from pad drilling, a rig must be capable of moving quickly from one well to another and be able to address the complexities associated with the growing number of wells per pad. In addition to quickly moving from well to well, omni-directional walking systems are ideally suited for pad drilling because they are capable of efficiently addressing situations on a pad in which wellbores are not precisely aligned or when level variations exist on the pad, which becomes increasingly likely as pads become larger and more complex.

Another method utilized by operators to increase efficiencies and maximize well economics is the drilling of longer lateral horizontal wells. Operators in our target areas have continued to increase the lateral length of their horizontal wells. Longer laterals provide greater production zones as the portion of the wellbore that passes through the target formation increases, optimizing the impact of hydraulic fracturing and stimulation. The drilling of longer laterals necessitates the use of increased horsepower drawworks and top drive systems, which provide maximum torque and rotational control and allows the operator to maintain the integrity of its drilling plan throughout the wellbore. Additionally, higher pressure mud pumps are required to pump fluids through significantly longer wellbores. The competitive advantage of higher pressure mud pumps grows as the lateral length increases, as only high pressure pumps can effectively address the severe pressure drop, while providing the required hydraulic horsepower at the bit face and sufficient flow to remove drill cuttings and keep the hole clean.

Pad Optimal Equipment

Cost effective development drilling in a manufacturing wellbore model requires more complex well designs, shorter cycle times, and the use of innovative technology in order to reduce an E&P company’s overall field development costs. Drilling rigs that are designed to maximize drilling efficiency, reduce cycle times, maximize energy efficiency, increase penetration rates while drilling, and drill longer-reach horizontal wells will reduce an E&P company’s overall field development costs and provide them with greater optionality when designing their field development program.

We believe that E&P companies drilling horizontal wells increasingly demand not only AC rigs that are optimal for horizontal drilling, but premium AC rigs such as our ShaleDriller rigs that are "pad optimal" that include the following minimum equipment and design features:

- *AC Programmable*. AC rigs use a variable frequency drive that allows precise computer control of motor speed during operations. This greater control of motor speed provides more precise drilling of the wellbore. Among other attributes, when compared to electrical SCR rigs and mechanical rigs, AC rigs are electrically more efficient, produce consistent torque, utilize regenerative braking, and have digital controls and AC motors that require less maintenance. AC rigs allow our customers to drill faster, which, in general, eliminates reservoir permeability damage, and to drill wellbores that more precisely track planned trajectories without doglegs. This, in turn, minimizes open hole time and enables our customers to more effectively and efficiently run casing, cement and successfully complete their wells.

- *Pad Optimized, Omni-Directional Walking System*. Omni-directional walking systems are designed to optimize pad drilling economics for our customers. Pad drilling involves the drilling of multiple wells from a single location, which provides benefits to the E&P company in the form of cost savings and accelerated cash flows. Our walking rigs move in any direction quickly between wellheads, rapidly and efficiently adjust to misaligned wellbores, walk over raised wellheads, and increase operational safety due to fewer required rig up and rig down movements.

- *Efficient Mobilization Between Drilling Sites*. A rig that can rapidly move between drilling sites has become increasingly desired by, and impactful to, E&P companies because it reduces cycle times allowing them to drill more wells in the same period of time. Our ShaleDriller rigs move rapidly on conventional rig moves between drilling sites.

- *1500-HP Drawworks*. 1500-HP drawworks are well suited for the development of the vast majority of our customers' unconventional resource assets. Compared to a 1000-HP or smaller rig, a 1500-HP rig has superior capability to handle extended drill string lengths required to drill long horizontal wells, which are becoming more common in the markets we serve. Our ShaleDriller fleet includes 33 1500-HP rigs and one 1000-HP rig.

- *7500psi Mud Systems*. The drilling of longer laterals necessitates the use of higher-pressure mud pumps to pump fluids through significantly longer wellbores. The competitive advantage of higher-pressure mud pumps grows as the lateral length gets longer, as only high pressure pumps can effectively address the severe pressure drop while providing the required hydraulic horsepower at the bit face and sufficient flow to remove drill cuttings and keep the hole clean. All ShaleDriller rigs are equipped with 7500psi mud systems, and all are capable of adding a third mud pump and fourth engine if a customer requires such additional equipment capacity.

In addition to these minimum characteristics, we believe E&P operators also increasingly desire drilling contractors with the ability to provide other flexible and varying equipment packages depending upon the specific nature of their drilling program and their field-development plans. Such equipment package options may include redundant third mud pumps, three simultaneously operating mud pumps powered by a fourth engine when greater hydraulic flow and pressure is required, greater setback capacity allowing efficient drilling of ultra-long horizontal laterals, or increased hookload when utilizing larger casing strings in combination with deeper wells. Our ShaleDriller fleet is capable of providing all of these varying equipment packages depending upon our customer's requirements. For example, we market 22 "200 Series" ShaleDriller rigs that are all fully capable of utilizing a third pump or fourth engine and nine slightly larger "300 Series" rigs that, in addition to third pump and fourth engine options, include the option for 25,000ft or greater racking capacity and one million-pound hook load. When the planned conversions of our three operating SCR rigs and two idle rigs are complete, we expect that our "300 Series" rigs will increase to 14 rigs.

Customer Contracts and Backlog

Drilling contracts are obtained through competitive bidding or as a result of negotiations with customers, and may cover multi-well and multi-year projects. Each of our rigs operates under a separate drilling contract or drilling order subject to a master drilling contract. We perform drilling services on a "daywork" contract basis, under which we charge a specified rate per day. The dayrate under each of our contracts is a negotiated price determined by the location, depth and complexity of the wells to be drilled, operating conditions, the duration of the contract, and market conditions. We have not accepted any, and do not anticipate entering into, any "turn-key" (fixed sum to deliver a hole to a stated depth) or "footage" (fixed rate per foot of hole drilled) contracts. The duration of land drilling contracts can vary from "well-to-well" or to a fixed term ranging from a few months to several years. The revenue generated by a rig in a given year is the product of the dayrate fee and the number of days the rig is earning this fee based on activity and the terms of the contract, referred to as utilization. "Well-to-well" contracts are typically cancelable at the option of either party upon the completion of drilling at a particular site. Fixed-term contracts customarily provide for termination at the election of the customer, with an "early termination payment" to be paid to the drilling contractor if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances, such as destruction of a drilling rig, the drilling contractor's bankruptcy, sustained unacceptable performance by the drilling contractor or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to the drilling contractor. Drilling contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution, which are subject to negotiation on a contract-by-contract basis.

Under a typical daywork contract, we earn a dayrate fee while the rig is operating, and we earn a moving rate fee while the rig is moving between wells or drilling locations under the contract. If the rig is on standby or is not drilling due to a force majeure event unrelated to damage to the rig, contracts typically provide that we earn a rate during this period of time, which rate may be equal to or less than the operating rate.

Mobilization rates are determined by market conditions and are generally reimbursed by the customer. In most instances, contracts typically provide for additional payments associated with this initial mobilization of a drilling rig and that we receive a demobilization fee at the end of the contract term in certain circumstances equal to the estimated cost to transport the rig from the final drilling location and to compensate us for the estimated demobilization time.

Drilling contracts typically provide that the contractor continues to earn the operating dayrate while a rig is not operating but under repair or maintenance, so long as the non-operating time due to repair and maintenance does not exceed a specified number of hours in a given day or calendar month.

As of December 31, 2018, our backlog of term contracts was $120.9 million, of which $114.2 million is expected to be realized during 2019. Our backlog does not include potential reductions in rates for unscheduled standby during periods in which the rig is moving, on standby or incurring maintenance and repair time in excess of contractually allowed downtime. In addition, rigs under term contracts may realize revenue on a standby-without-crew basis, which allows us to preserve our expected cash margins from the contract but reduces our overall top line revenue. To the extent that we have rigs under term contracts operating on a standby or standby-without-crew basis, our top line revenues will be less than our reported backlog from term contracts.

The following chart summarizes the weighted-average number of rigs as of December 31, 2018 that we have operating under term contracts through 2019 and 2020.

	Quarter Ending March 31, 2019	Quarter Ending June 30, 2019	Quarter Ending September 30, 2019	Quarter Ending December 31, 2019	Year Ending 2020
Weighted-Average Number of Rigs[(1)]	30.3	18.6	8.2	2.6	0.8

(1) Weighted-average number of rigs calculated based upon the aggregate number of expected revenue days to be realized during the period from term contracts divided by the number of days in the applicable period. Term contracts include all contracts with original terms of 6 months or greater, and exclude well-to-well or short-term contracts.

Our Customers

Customers for contract drilling services in the United States include major oil and natural gas companies, independent oil and natural gas companies, as well as numerous small to mid-sized publicly-traded and privately held oil and natural gas companies. We market our contract drilling services to all such customers. During 2018, our customers representing more than 10% of our revenues were GeoSouthern Energy Corporation and COG Operating, LLC, a subsidiary of Concho Resources, Inc.

Industry/Competition

To a large degree, our business depends on the level of capital spending by oil and natural gas companies for exploration, development and production activities. A sustained increase or decrease in the price of oil and natural gas could have a material impact on the exploration, development and production activities of our customers and could materially affect our financial position, results of operations and cash flows.

The contract drilling industry is highly competitive and has become even more so under current market conditions. The price for contract drilling services is a key competitive factor in the United States land contract drilling markets, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe the principal competitive factors in our markets are availability and condition of equipment, efficiency of equipment, quality of personnel, service quality, experience and safety record.

Many of our competitors are larger, publicly-held corporations with significantly greater resources and longer operating histories than us. Our largest competitors for high-end AC land drilling contract services are Helmerich & Payne, Inc., Precision Drilling Corporation, Nabors Industries, Ltd. and Patterson-UTI Energy, Inc.

Many of our larger competitors are able to offer ancillary products and services with their contract drilling services, and recently, some of our larger competitors have begun integrating and offering contract drilling services in connection with directional drilling and other services that we do not offer.

Government and Environmental Regulation

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

- drilling of oil and natural gas wells;
- the relationships with our employees;
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids; and
- use of underground storage tanks.

To date, we do not believe applicable environmental laws and regulations in the United States have required the expenditure by the contract drilling industry of significant resources outside the ordinary course of business. 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 and local laws and regulations that relate to the oil and natural gas industry. The adoption of laws and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling and production, and otherwise have an adverse effect on our operations. Federal, state and local environmental laws and regulations currently apply to our operations and may become more stringent in the future. Any suspension or moratorium of the services we provide, whether or not short-term in nature, by a federal, state or local governmental authority, could have a material adverse effect on our business, financial condition and results of operation.

In the United States, the federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended ("CERCLA"), and comparable state statutes impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of a "hazardous substance" into the environment. These persons include:

- current and past owners and operators of the site where the release occurred, and
- persons who disposed of or arranged for the disposal of "hazardous substances" released at the site.

Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and RCRA excludes certain classes of exploration and production wastes from regulation as hazardous waste under Subtitle C of RCRA, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and the Oil Pollution Act of 1990, as amended (the "Oil Pollution Act"), and analogous state laws and their respective implementing regulations govern:

- the prevention of discharges of pollutants, including oil and produced water spills, into waters of the United States; and
- liability for drainage into waters of the United States.

The Oil Pollution Act imposes strict liability for a comprehensive and expansive list of damages from an oil spill into waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages.

Administrative, civil or criminal 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 administrative, civil or criminal actions. Although the liability for owners and operators is the same under the federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

Our contract drilling services will be marketed in oil and natural gas producing regions that utilize hydraulic fracturing services to enhance the production of oil and natural gas from formations with low permeability, such as shales. Due to concerns raised relating to potential impacts of hydraulic fracturing on ground water quality and the increased occurrence of seismic activity, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities, which in turn could have an adverse effect on the contract drilling services that we render for our exploration and production customers.

Our operations are also subject to federal, state and local laws, rules and regulations for the control of air emissions, including the federal Clean Air Act. The federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through, for example, air emissions permitting programs. In addition, the Environmental Protection Agency (the "EPA") has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources including pursuing the energy extraction sector under a National Compliance Initiative. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Finally, more stringent federal, state and local regulations, such as the EPA rules issued in April 2012, which add new requirements for the oil and natural gas sector under the New Source Review Program and the National Emission Standards for Hazardous Air Pollutants program, could result in increased costs and the need for operational changes. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

On December 7, 2009, the EPA announced its findings that emissions of GHG present an “endangerment to human health and the environment.” The EPA based this finding on a conclusion that greenhouse gases are contributing to the warming of the Earth’s atmosphere and other climate changes. The EPA began to adopt regulations that would require a reduction in emissions of greenhouse gases from certain stationary sources and has required monitoring and reporting for other stationary sources. Mandatory reporting requirements for additional regional, federal or state requirements have been imposed and additional requirements may be imposed in the future. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse effect on our operations and demand for our services. For example, during 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and natural gas production. In May 2016, the EPA finalized regulations that set methane emission standards for new and modified oil and natural gas facilities, including production facilities. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Finally, it should be noted that some scientists have concluded that 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 exploration and production operations.

We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in compliance with these applicable requirements and with other OSHA and comparable requirements.

Additionally, environmental laws such as the federal Endangered Species Act (“ESA”) and the Migratory Bird Treaty Act, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our customers’ properties may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species or the designation of previously unprotected areas as a critical habitat could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Risks and Insurance

Our operations are subject to the many hazards inherent in the drilling business, including:

- accidents at the work location;
- blow-outs;
- cratering;
- fires; and
- explosions.

These and other hazards could cause:

- personal injury or death;
- suspension of drilling operations; or
- damage or destruction of our equipment and that of others;
- damage to producing formations and surrounding areas; and
- environmental damage.

Damage to the environment, including property contamination in the form of soil or ground water contamination, could also result from our operations, including through:

- oil or produced water spillage;
- natural gas leaks; and
- fires.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we may not be fully insured against all risks, either because insurance is not available or because of the high premium costs. Such risks include personal injury, well disasters, extensive fire damage, damage to the environment, and other hazards. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our rigs and other assets, employer's liability, automobile liability, commercial general liability insurance and workers compensation insurance. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, our drilling rigs and other assets, such insurance does not cover the full replacement cost of the rigs or other assets, and we do not carry insurance against loss of earnings resulting from such damage. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on our financial condition and results of operations. Further, we may experience difficulties in collecting from insurers, or such insurers may deny all or a portion of our claims for insurance coverage.

In addition to insurance coverage, we also attempt to obtain indemnification from our customers for certain risks. These indemnities typically require our customers to hold us harmless in the event of loss of production or reservoir damage. There is no assurance that we will obtain such contractual indemnity, and if obtained, whether such indemnity will be enforceable, whether the customer will be able to satisfy such indemnity or whether such indemnity will be supported by adequate insurance maintained by the customer.

If a significant accident or other event occurs and is not fully covered by insurance or is not an enforceable or recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations. See "Risk Factors - Our operations involve operating hazards, which if not insured or indemnified against, could adversely affect our results of operations and financial condition."

Employees

As of December 31, 2018, we had approximately 900 employees, none of whom were contract employees or were represented by a union. The number of our employees fluctuates depending on our construction and drilling activities.

Seasonality

Seasonality has not significantly affected our overall operations. However, our drilling operations can be affected by severe winter storms or other weather related events. Additionally, toward the end of some years, we experience slower contracting activity as customers' capital expenditure budgets are depleted.

Drilling Equipment, Suppliers and Subcontractors

We use many suppliers of drilling equipment and services. Although these suppliers, drilling equipment and services have historically been available, there is no assurance that such drilling equipment and services will continue to be available on favorable terms or at all. We also utilize numerous manufacturers and independent subcontractors from various trades to supply key components to the rigs that we construct for our use. These key components include masts and substructures, top drives, high pressure mud pumps, pressure control equipment, engines, and VFD control systems. We believe that we have alternative sources for each of these components.

Website Access to Our Periodic SEC Reports

Our internet address is http://www.icdrilling.com. We file and furnish Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, and amendments to these reports, with the Securities and Exchange Commission (the "SEC"), which are available free of charge through our website as soon as reasonably practicable after such reports are filed with or furnished to the SEC. The SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file and furnish electronically with the SEC.

We may from time to time provide important disclosures to investors by posting them in the investor relations section of our website, as allowed by SEC rules. Information on our website is not incorporated by reference into this Annual report on Form 10-K and you should not consider information on our website as part of this Annual Report on Form 10-K.

ITEM 1A. *RISK FACTORS*

We face many challenges and risks in the industry in which we operate. You should carefully consider each of the following risk factors and all of the other information set forth in this Annual Report on Form 10-K, including our consolidated financial statements and related notes, and the documents and other information incorporated by reference herein, before investing in our shares. The risks and uncertainties described are not the only ones we face. Additional risk factors not presently known to us or which we currently consider immaterial may also adversely affect us. If any of these risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

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

As a provider of land-based contract drilling services, our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events as well as natural disasters have contributed to oil and natural gas price volatility and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect us in many ways by negatively impacting:

- our revenues, cash flows and profitability;
- our ability to recontract drilling rigs upon expiration of existing contracts;
- our ability to recontract drilling rigs at profitable dayrates;
- our ability to invest in capital expenditures necessary to maintain our drilling fleet and respond to customer requirements;
- the fair market value of our drilling rig fleet and other assets;
- our ability to obtain additional debt and equity capital required to implement our operating strategy, and the cost of that capital; and
- our ability to retain skilled rig personnel whom we need to implement our growth strategy.

Depending on the market prices of oil and natural gas, oil and natural gas exploration and production companies may cancel or curtail their drilling programs and may lower production spending on existing wells, thereby reducing demand for our services. Many factors beyond our control affect oil and natural gas prices, including, but not limited to:

- the cost of exploring for, producing and delivering oil and natural gas;
- the discovery and development rate of new oil and natural gas reserves, especially shale and other unconventional natural gas resources for which we market our rigs;
- the rate of decline of existing and new oil and natural gas reserves;
- available pipeline and other oil and natural gas transportation capacity;
- the levels of oil and natural gas storage;
- the ability of oil and natural gas exploration and production companies to raise capital;
- economic conditions in the United States and elsewhere;
- actions by the Organization of Petroleum Exporting Countries;
- political instability in the Middle East and other major oil and natural gas producing regions;
- governmental regulations, sanctions and trade restrictions, both domestic and foreign;
- domestic and foreign tax policy;
- the availability of and constraints in pipeline, storage and other transportation capacity in the basins in which we operate, including, for example, takeaway constraints experienced in the Permian Basin
- weather conditions in the United States;
- the pace adopted by foreign governments for the exploration, development and production of their national reserves;
- the price of foreign imports of oil and natural gas;
- the strength or weakness of the United States dollar;
- the overall supply and demand for oil and natural gas; and
- the development of alternate energy sources and the long-term effects of worldwide energy conservation measures.

In addition, if oil and natural gas prices decline, companies that planned to finance exploration, development or production projects through the capital markets may be forced to curtail, reduce, postpone or delay drilling activities even further, and also may experience an inability to pay suppliers. Adverse conditions in the global economic environment could also impact our vendors' and suppliers' ability to meet obligations to provide materials and services in general. If any of the foregoing were to occur, or if current depressed market conditions continue for a prolonged period of time, it could have a material adverse effect on our business and financial results and our ability to timely and successfully implement our growth strategy.

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration (the "EIA"). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid-fifties in February 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Any loss of large customers could have a material adverse effect on our financial condition and results of operations.

Our customer base consists of E&P companies that drill oil and natural gas wells in the United States in the regions where we market our rigs. As of December 31, 2018, we have rigs operating or earning revenues from 16 different customers, including one customer who has contracted seven, or 22%, of our rigs, one customer who has contracted four, or 13%, of our rigs, two customers who have contracted three, or 9%, of our rigs and three customers who have contracted two, or 6%, of our rigs. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. Daywork contracts in the contract drilling industry typically do not obligate those customers to order additional services from the drilling contractor beyond those for which they have currently contracted. If a customer decided not to continue to use our services or to terminate an existing contract, or if there is a change of management or ownership of a customer or a material adverse change in the financial condition of one of our customers, it could have a material adverse effect on our revenues, cash flows, and financial condition.

If our customers delay paying or fail to pay a significant amount of our outstanding receivables, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

In most cases, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. If our customers delay paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, results of operations, and financial condition.

The significant majority of our marketed rigs are operating under contracts with terms expiring during 2019. If we are unable to continue to operate rigs in the spot-market or renew our expiring contracts or continue their operation in the spot-market, it could have a material adverse effect on our results of operations and financial condition.

Upon expiration of a drilling contract, our customers have no obligation to extend the contract term or recontract the drilling rig, and may elect to release the rig. In the event a customer elects to terminate a drilling contract prior to the expiration of its drilling term, all of our current drilling contracts provide that our customers pay an early termination payment. We cannot assure that any replacement contract can be obtained for any of our rigs operating in the spot-market or with terms expiring, and if obtained, that it would be on terms as favorable as those of our existing drilling contracts or at profitable levels. The failure to renew or timely replace one or more of our expiring contracts could have a material adverse effect on our results of operations and financial condition.

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

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

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

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

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

Although, we seek to protect ourselves from some but not all operating hazards through insurance coverage, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers. However, customers who provide contractual indemnification protection may not in all cases maintain adequate insurance or otherwise have the financial resources necessary to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. We do not carry loss of business insurance for a rig being out of service.

We maintain insurance against some, but not all, of the potential risks affecting our operations and only in coverage amounts and deductible levels that we believe to be economical. Our insurance coverage includes deductibles which must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable. Incurring a liability for which we are not fully insured or indemnified could have a material adverse effect on our financial condition and results of operations.

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

We encounter substantial competition from other drilling contractors. The competition in the markets in which we operate has intensified as recent mergers among E&P companies have reduced the number of available customers and the downturn in oil prices has decreased demand for drilling rigs and resulted in downward pricing pressure on operating drilling rigs.

Contract drilling companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. Most drilling services contracts are awarded on the basis of competitive bids, which also results in price competition.

In addition to pricing, we believe the principal competitive factors in our markets are availability and condition of equipment, quality of personnel, efficiency of equipment, service quality, experience and safety record. The success of our business depends on our ability to offer safe and highly efficient operations, the quality and efficiency of our rigs and the skills and experience of our rig crews.

As a result of competition, we may lose market share or be unable to maintain or increase prices for our present services or to acquire additional business opportunities, which could have a material adverse effect on our business, results of operations and financial condition. In addition, the failure to maintain an adequate safety record could harm our ability to secure new drilling contracts. As a relatively new contract driller with limited operating history, there can be no assurance that we will be able to maintain the reputation for safety and quality required to successfully compete against our competition.

We face competition from many competitors with greater resources and greater ability to rapidly respond to changing customer requirements and market conditions.

We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than we do. Many of our larger competitors are able to offer ancillary products and services with their contract drilling services, and recently, some of our larger competitors have begun integrating and offering contract drilling services in connection with directional drilling and other services that we do not offer. In this regard, large diversified oilfield service companies have begun to market bundled services, including contract drilling services, in the United States. If any of these combined offerings gain acceptance within the United States market, it could place us at a competitive disadvantage that has an adverse impact on our future results of operations and profitability.

Furthermore, some of our competitors' greater capabilities in these areas may enable them to better withstand industry downturns, compete more effectively on the basis of price and technology, retain skilled rig personnel, and build new rigs or acquire and refurbish existing rigs so as to be able to place rigs into service more quickly than us in periods of high drilling demand.

In addition, we compete with several smaller companies capable of competing effectively on a regional or local basis. Smaller competitors may be able to respond more quickly to new or emerging technologies and services and changes in customer requirements.

Finally, some E&P companies perform horizontal and directional drilling on their wells using their own equipment and personnel. Any increase in the development and utilization of in-house drilling capabilities by our customers could decrease the demand for our services and have a material adverse impact on our business.

New technology may cause our drilling methods or equipment to become less competitive.

The drilling industry is subject to the introduction of new drilling and completion methods and equipment using new technologies, some of which may be subject to patent protection. Changes in technology or improvements in competitors' equipment could make our equipment less competitive or require significant capital investments to build and maintain a competitive advantage. Further, we may face competitive pressure to design, implement or acquire certain new technologies at a substantial cost. Some of our competitors have greater financial, technical and personnel resources that may allow them to implement new technologies before we can. If we are unable to implement new and emerging technologies on a timely basis or at an acceptable cost, it may have a material adverse effect on our business, results of operations, financial condition and growth strategy.

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

Hydraulic fracturing is a commonly used process that involves injection of water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could potentially increase our costs of operations and cause a decrease in drilling activity levels in the Permian Basin and other unconventional resource plays and an associated decrease in demand for our rigs and service, any or all of which could adversely affect our financial position, results of operations and cash flows.

The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act ("SDWA") to exclude certain hydraulic fracturing practices from the definition of "underground injection." The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and published guidance relating to such practices in February 2014. From time to time, Congress has considered bills to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, potentially including chemical disclosure requirements. At the state level, several states in which we operate have adopted regulations requiring the disclosure of certain information regarding hydraulic fracturing fluids.

Scrutiny of hydraulic fracturing activities continues in other ways. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA conducted a study of the potential impacts of hydraulic fracturing on drinking water and issued a final report in December 2016. This study and other studies that may be undertaken by the EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other statutory and/or regulatory mechanisms. Additionally, in June 2016, the EPA published a rule establishing pretreatment standards which prohibit the disposal of unconventional oil and natural gas wastewater at publicly owned treatment works.

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

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing in the unconventional resource plays where we focus our operations.

We depend on the services of key executives, the loss of whom could materially harm our business.

Our senior executives are important to our success because they are instrumental in setting our strategic direction, operating our business and technology, identifying, recruiting and training key personnel, and identifying customers and expansion opportunities. We also depend on the relationships that our senior management has with many of our customers. Losing the services of any of these individuals could adversely affect our business until a suitable replacement could be found. We do not maintain key man life insurance on any of our senior executives. As a result, we are not insured against any losses resulting from the death of our key employees.

Rig upgrade and refurbishment projects, as well as the reactivation of rigs that have been idle for six months or longer, are subject to risks which could cause delays or cost overruns and adversely affect our cash flows, results of operations, and financial position.

Rigs being upgraded, converted or re-activated following a period of stack may experience start-up complications and may encounter other operational problems that could result in significant delays, uncompensated downtime, reduced dayrates or the cancellation, termination or non-renewal of drilling contracts. Rig upgrade projects are subject to risks of delay or significant cost overruns inherent in any large construction project from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment or shipyard construction;
- failure of equipment to meet quality and/or performance standards;
- financial or operating difficulties of equipment vendors;
- unanticipated actual or purported change orders;
- inability by us or our customer to obtain required permits or approvals, or to meet applicable regulatory standards in our areas of operations;
- unanticipated cost increases between order and delivery;
- adverse weather conditions and other events of force majeure;
- design or engineering changes; and
- work stoppages and other labor disputes.

The occurrence of any of these events could have a material adverse effect on our cash flows, results of operations and financial position.

Our current estimated backlog of contract drilling revenue may not ultimately be realized.

As of December 31, 2018, our estimated 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 $120.9 million. Our backlog does not include potential reductions in rates for unscheduled standby during periods in which the rig is moving, on standby or incurring maintenance and repair time in excess of contractually allowed downtime. To the extent that we have rigs under term contracts operating on a standby or standby-without-crew basis, our top line revenues will be less than our reported backlog from term contracts.

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. Additionally, 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, such as those we are currently experiencing, or otherwise, customers may be unable to satisfy their contractual obligations or may seek to terminate, renegotiate or fail to honor their contractual obligations. In addition, we may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or negotiate our contracts for various reasons, including those described above. As a result, we may be unable to realize all of our current contract drilling backlog. In addition, the renegotiation or termination of fixed-term contracts without the receipt of early termination payments could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our operating and maintenance costs with respect to our rigs include fixed costs that will not decline in proportion to decreases in dayrates.

We do not expect our operating and maintenance costs with respect to our rigs to necessarily fluctuate in proportion to changes in operating revenue. Operating revenue may fluctuate as a function of changes in dayrate, but costs for operating a rig and property taxes are generally fixed or only semi-variable regardless of the dayrate being earned. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare our rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. Moreover, when our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase due to higher salary levels, inflation, and increases in workers' compensation insurance. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

We participate in a capital intensive business. We may not be able to finance future growth of our operations.

The contract drilling industry is capital intensive. Our cash flow from operations and the continued availability of credit are subject to a number of variables, including general economic conditions, conditions in the oil and natural gas market, and more specifically, our rig utilization rates, operating margins and ability to control costs and obtain contracts in a competitive industry. Our cash flow from operations and present borrowing capacity may not be sufficient to fund our anticipated capital expenditures and working capital requirements. We may from time to time seek additional financing, either in the form of bank borrowings, sales of debt or equity securities or otherwise. To the extent our capital resources and cash flow from operations are at any time insufficient to fund our activities or repay our indebtedness as it becomes due, we will need to raise additional funds through public or private financing or additional borrowings. We may not be able to obtain any such capital resources in the amount or at the time when needed. Based upon the significant downturn in market conditions, any new sources of debt capital would require substantially higher interest requirements, and any new sources of equity capital could be substantially dilutive to existing shareholders. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile could affect our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets. If we are at any time not able to obtain the necessary capital resources, our financial condition and results of operations could be materially adversely affected.

We may be unable to integrate operations following our combination with Sidewinder Drilling LLC and successfully realize anticipated benefits from the Sidewinder Merger.

On October 1, 2018, we consummated the merger transactions contemplated by the Agreement and Plan of Merger between us and Sidewinder Drilling, LLC. Realizing any of the anticipated benefits of the merger, including cost synergies and additional revenue opportunities, involves a number of challenges. The failure to meet these integration challenges could seriously harm our results of operations and the market price of our common stock may decline as a result.

Realizing the benefits of the transaction depends in part on the integration of technology, operations, personnel and sales activity of the two companies. These integration activities are complex and time-consuming, and we may encounter unexpected difficulties or incur unexpected costs, including:

- challenges in combining the cultural and management teams of two different companies;
- challenges in combining rig product offerings, including integration of the underlying technology, and sales and marketing activities;
- our inability to achieve the cost savings and operating synergies anticipated in the transaction, which would prevent us from achieving the positive earnings gains expected as a result of the transaction;
- diversion of management attention from ongoing business concerns to integration matters;

- difficulties in consolidating and rationalizing information technology platforms and administrative infrastructures;
- complexities in managing a larger company than before the completion of transaction;
- difficulties in the assimilation of the personnel and the integration of two business cultures;
- challenges in demonstrating to our customers and to customers of Sidewinder that the transaction will not result in adverse changes in product and technology offerings, customer service standards or business focus; and
- possible cash flow interruption or loss of revenue as a result of change of ownership transitional matters.

Although this integration is ongoing, we may not successfully integrate operations in a timely manner, and we may not realize the anticipated net reductions in costs and expenses and other benefits and synergies of the merger to the extent, or in the timeframe, anticipated. In addition to the integration risks discussed above, our ability to realize the benefits and synergies of the merger could be adversely impacted by practical or legal constraints on our ability to combine operations. If our management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer and our results of operations and financial condition may be harmed.

We may be adversely impacted by work stoppages or other labor matters.

We depend on skilled employees to build and operate our rigs, and any prolonged labor disruption involving our employees could have a material adverse impact on our results of operations and financial condition by disrupting our ability to perform drilling-related services for our customers. Moreover, unionization efforts have been made from time to time within our industry, with varying degrees of success. Any such unionization could increase our costs or limit our flexibility.

Failure to hire and retain skilled personnel could adversely affect our business.

Our ability to be productive and profitable depends upon our ability to employ and retain skilled personnel and we cannot assure that at times of high demand we will be able to retain, recruit and train an adequate number of skilled workers. In addition, our ability to expand our operations will depend in part on our ability to increase the size of our skilled labor force. Potential inability or lack of desire by workers to commute to our facilities and job sites and competition for workers from competitors or other industries are factors that could affect our ability to attract and retain workers. A significant increase in the wages paid by competing employers or other industries could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either or both of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired. Our inability to attract and retain skilled workers in sufficient numbers to satisfy our existing service contracts and enter into new contracts could materially adversely affect our business, financial condition, results of operations and growth strategy

We depend on a limited number of vendors, some of which are thinly capitalized and the loss of any of which could disrupt our operations.

Our contract drilling operations depend upon the availability of various rig equipment, including VFD drives and drillers cabins, top drives, mud pumps, engines and drill pipe, as well as replacement parts, related rig equipment and fuel. Some of these have been in short supply from time to time. In addition, key rig components critical to the operation, construction or upgrade of our rigs are either purchased from or fabricated by a limited number of vendors, including vendors that may compete against us from time to time. For many of these products and services, there are only a limited number of vendors and suppliers available to us.

We do not currently have any long-term supply contracts with any of our suppliers or subcontractors and may be at a competitive disadvantage compared to our larger competitors when purchasing from these suppliers and subcontractors. Shortages could occur in these essential components due to an interruption of supply or increased demands in the industry. If we are unable to procure certain of such rig components or services from our subcontractors we would be required to reduce or delay our rig construction and other operations, which could have a material adverse effect on our business, results of operations, financial condition and growth strategy.

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

Increased or decreased demand among drilling contractors and our customers for consumable supplies, including fuel, water and ancillary rig equipment, such as pumps, valves, drill pipe and engines, may lead to delays in obtaining these materials and our inability to operate our rigs in an efficient manner. We have periodically experienced increased lead times in purchasing ancillary equipment for our drilling rigs. To the extent there are significant delays in being able to purchase important components for our rigs, certain of our rigs may not be available for operation or may not be able to operate as efficiently as expected, which could adversely affect our results of operations and financial condition.

In addition, our customers typically purchase the fuel and water for their operations, including fuel that runs our drilling rigs, and thus bear the financial impact of increased prices. However, prolonged shortages in the availability of fuel or water to conduct drilling and completion activities could result in the suspension of our contracts or reduce demand for our contract drilling services and have a material adverse effect on our financial condition and results of operations.

Legal proceedings could have a negative impact on our business.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any litigation 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.

Regulatory compliance costs and restrictions, as well as any delays in obtaining permits by our customers for their operations, could impair our business.

The operations of our customers are subject to or impacted by a wide array of regulations in the jurisdictions in which they operate. As a result of changes in regulations and laws relating to the oil and natural gas industry, including land drilling, our customers' operations could be disrupted or curtailed by governmental authorities. In most states, our customers are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities. Such permits are typically required by state agencies, but can also be required by federal and local governmental agencies. The requirements for such permits vary depending on the location where such drilling and completion activities will be conducted. As with all governmental permitting processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit to be issued, and the conditions which may be imposed in connection with the granting of the permit. Additionally, the high cost of compliance with applicable regulations may cause customers to discontinue or limit their operations or defer planned drilling, and may discourage companies from continuing development activities. As a result, demand for our services could be substantially affected by regulations adversely impacting the oil and natural gas industry.

We are subject to environmental, health and safety laws and regulations that may expose us to significant liabilities for penalties, damages or costs of remediation or compliance.

Our operations are subject to federal, regional, state and local laws and regulations relating to protection of natural resources and the environment, health and safety aspects of our operations and waste management, including the transportation and disposal of waste and other materials. These laws and regulations may impose numerous obligations on our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from our facilities, the imposition of substantial liabilities for pollution resulting from our operations and the application of specific health and safety criteria addressing worker protection. Failure to comply with these laws and regulations could result in investigations, restrictions or orders suspending well operations, the assessment of administrative, civil and criminal penalties, the revocation of permits and the issuance of corrective action orders, any of which could have a material adverse effect on our business, results of operations and financial condition.

There is inherent risk of environmental costs and liabilities in our business as a result of our handling of petroleum hydrocarbons and oilfield and industrial wastes, air emissions and wastewater discharges related to our operations, and historical industry operations and waste disposal practices. Some environmental laws and regulations may impose strict, joint and several liability, which means that in some situations, we could be exposed to liability as a result of our conduct that was without fault or lawful at the time it occurred or as a result of the conduct of, or conditions caused by, prior operators or other third parties. Clean-up costs and other damages arising as a result of environmental laws and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on our financial condition and results of operations.

Laws protecting the environment generally have become more stringent over time and are expected to continue to do so, which could lead to material increases in costs for future environmental compliance and remediation. The modification or interpretation of existing laws or regulations, or the adoption of new laws or regulations, could curtail exploratory or developmental drilling for oil and natural gas, could limit well servicing opportunities or impose unforeseen liabilities. We may not be able to recover some or any of our costs of compliance with these laws and regulations from insurance.

Potential listing of species as "endangered" under the federal ESA could result in increased costs and new operating restrictions or delays on our oil and natural gas exploration and production customers, which could adversely reduce the amount of contract drilling services that we provide to such customers.

The federal ESA and analogous state laws regulate a variety of activities, including oil and natural gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species or the designation of previously unprotected areas as a critical habitat could cause oil and natural gas exploration and production operators to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas, including support services that we provide to such operators under our contract drilling services segment. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future provide field services. For instance, the sage grouse, the lesser prairie-chicken and certain wildflower species, among others, are species that have been or are being considered for protected status under the ESA and whose range can coincide with our oil and natural gas production activities. The presence of protected species in areas where operators for whom we provide contract drilling services conduct exploration and production operations could impair such operators' ability to timely complete well drilling and development and, consequently, adversely affect the amount of contract drilling or other field services that we provide to such operators, which reduction of services could have a significant adverse effect on our results of operations and financial position.

Climate change legislation or regulations restricting or regulating emissions of greenhouse gases could result in increased operating costs and reduced demand for our field services.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the Earth's atmosphere and oceans and contribute to global warming and other environmental effects, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and natural gas industry. During 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and natural gas production. In May 2016, the EPA finalized regulations that set methane emission standards for new and modified oil and natural gas facilities, including production facilities. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change and was among the 195 nations that signed an international accord in December 2015 with the objective of limiting greenhouse gas emission. The Paris Agreement entered into force in November 2016; however, the United States announced its intention to withdraw from the Paris Agreement on June 1, 2017. The United States' status and continued participation in these and other initiatives or regulatory changes could result in increased costs of development and production and could have adverse effects on our operations. Additionally, certain U.S. states and regional coalitions of states have adopted measures regulating or limiting greenhouse gases from certain sources or have adopted policies seeking to reduce overall emissions of greenhouse gases. The adoption and implementation of any international treaty or of any federal or state legislation or regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with our operations and other sources within the industrial or energy sectors. Such legislation or regulations could adversely affect demand for the production of oil and natural gas and thus reduce demand for the services we provide to oil and natural gas producers as well as increase our operating costs by requiring additional costs to operate and maintain equipment and facilities, install emissions controls, acquire allowances or pay taxes and fees relating to emissions, which could adversely affect our results of operations and financial condition. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods and other climatic events, which if any such effects were to occur, could have adverse physical effects on our operations, physical assets and field services to exploration and production operators.

The effects of severe weather could adversely affect our operations.

Changes in climate due to global warming trends could adversely affect our operations by limiting, or increasing the costs associated with, equipment or product supplies. In addition, coastal flooding and adverse weather conditions such as increased frequency and/or severity of hurricanes could impair our ability to operate in affected regions of the country. Oil and natural gas operations of our customers located in Louisiana and parts of Texas may be adversely affected by hurricanes and tropical storms, resulting in reduced demand for our services. Repercussions of severe weather conditions may include: curtailment of services; weather-related damage to facilities and equipment; suspension of operations; inability to deliver equipment, personnel and products to job sites in accordance with contract schedules; and loss of productivity. These constraints could delay our operations and materially increase our operating and capital costs. Unusually warm winters also adversely affect the demand for our services by decreasing the demand for natural gas.

Our business is subject to cybersecurity risks and threats.

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

Any future implementation of price controls on oil and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either oil, natural gas, or both. There is no way at this time to know what results these efforts may have. However, any future limits on the price of oil or natural gas could have a material adverse effect on our business, financial condition and results of operations.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Liquidity

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance indebtedness depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the interest or principal, when due, on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our credit facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition subject to certain defined exceptions. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our existing debt instruments contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- transfer, lease or dispose of all or substantially all of our assets;
- make certain payments;
- create or incur liens;
- purchase, hold or acquire capital stock or certain other types of securities;
- pay cash dividends;

- enter into certain transactions with affiliates; and
- engage in certain other transactions without the prior consent of the lenders.

A breach of any covenant in any of our debt instruments would result in a default. A resulting event of default, if not waived, could result in acceleration of the payment of the indebtedness outstanding under, and a termination of, these debt instruments. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

The borrowing base under our revolving credit facility may decline during 2019.

At December 31, 2018, the borrowing base under our ABL Credit Facility was $32.8 million, and we had $27.7 million of availability remaining of our $40.0 million commitment on that date. The borrowing base under the ABL Credit Facility is calculated based upon 85% of the sum of our eligible accounts receivable. In most circumstances, all of accounts receivable are considered eligible unless they are more than 90 days past due. If at any time our borrowing base falls below our outstanding balance under our ABL Credit Facility, and we were not able to promptly repay such deficiency, we would be required to repay to the banks any deficiency amount. In such event, if our available cash balances were not sufficient to repay such amounts, we would be required to obtain other debt or equity financing necessary to cure such deficiency, and there can be no assurance that such additional financing sources would be available to us, or available on terms acceptable to us. Any inability to timely cure any deficiency between our borrowing base and credit facility balance may have a material adverse effect on our liquidity and financial condition.

A failure of any of our lenders to honor commitments or advance funds under our existing debt instruments would have a material adverse effect on our ability to fund our operations and business strategy.

Our ABL Credit Facility limits the amounts we can borrow up to a borrowing base amount which is calculated monthly and is based on a percentage of our eligible accounts receivable. The borrowing base under our ABL Credit Facility was $32.8 million as of December 31, 2018, with lender commitments of $40.0 million. Our Term Loan Facility also contains a committed accordion feature that allows us to borrow up to an additional $15 million during the term of that facility.

In the future, we may not be able to access adequate funding under our ABL Credit Facility as a result of a decrease in borrowing base or under any of our outstanding debt facilities due to an unwillingness or inability on the part of lending counterparties to meet their funding obligations. As a result, we may be unable to implement our strategic plans, make acquisitions or capital expenditures or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

Our ability to comply with the financial covenants contained in our debt instruments is based upon our future cash flows and debt levels.

Both our existing ABL Credit Facility and Term Loan Facility contain a springing financial covenant requiring us to maintain a fixed charge coverage ratio ("FCCR") of 1.0 to 1.0. The FCCR is equal to adjusted EBITDA less capital expenditures divided by cash interest expense plus scheduled principal payments, cash dividends and capital lease obligations plus cash taxes paid. This covenant is only tested when excess availability under our ABL Credit Facility falls below 10% of our borrowing base.

In addition, our existing Term Loan Facility contains a minimum liquidity covenant that requires us to maintain at all times at least $10 million of liquidity, which can be comprised of cash plus availability under our ABL Credit Facility.

Our compliance with each of these covenants depends significantly upon our level of cash flows, which are based upon factors such as future dayrates and rig utilization that are difficult to predict based upon the cyclical nature of our industry. If we are not able to comply with the covenants contained in our debt facilities, we would be required to seek a waiver or amendment to the facility, or seek alternative financing sources, and there can be no assurance that we would be able to obtain such waivers, amendments or alternative financing sources. Any failure to comply with the financial covenants contained in our credit facility, or to cure any such non-compliance may have a material adverse effect on our liquidity and financial condition.

Our ability to complete our planned rig conversions and upgrades is dependent upon our ability to maintain adequate cash flow and liquidity and availability under our debt facilities.

A key component of our strategy is completing the conversion of three operating and one idle SCR rigs to AC pad-optimal status and the upgrade of an idle non-walking AC rig to full AC pad-optimal status. We have ordered the long lead-time items to complete the four SCR conversions, but our ability to complete these projects will be dependent upon adequate revenues to generate cash flows as well as maintaining availability under our debt facilities, and more importantly, on our ability to comply with the covenants under our debt facilities. Therefore, there is no assurance that we can complete all of these capital projects and fully execute our near-term strategic plans.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. Our debt carries a floating rate of interest linked to various indices, including LIBOR. A change in indices, including the announced discontinuation of LIBOR, resulting in interest rate increases on our debt could adversely affect our cash flow and operating results. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for capital expenditures and place us at a competitive disadvantage. For example, total long-term debt at December 31, 2018 included $132.6 million of floating-rate debt attributed to borrowings at an average interest rate of 9.84%, and the impact on annual cash flow of a 10% change in the floating-rate (approximately 0.98%) would be approximately $1.3 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2018; however, there are no assurances that possible rate changes would be limited to such amounts. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our desired growth and operating results.

Risks Related to our Common Stock

The market price of common stock of companies engaged in the oil and natural gas service industry, including our common stock price, has been highly volatile. Stock price volatility could adversely affect our business operations by, among other things, impeding our ability to attract and retain qualified personnel and to obtain additional financing.

In addition to the other risk factors discussed in this section, the price and volume volatility of our common stock may be affected by:

- operating results that vary from the expectations of securities analysts and investors;
- factors influencing the levels of global oil and natural gas exploration and exploitation activities, such as a downturn in oil prices;
- the operating and securities price performance of companies that investors or analysts consider comparable to us;
- announcements of strategic developments, acquisitions and other material events by us or our competitors; and
- changes in global financial markets and global economies and general market conditions, such as interest rates, commodity and equity prices and the value of financial assets.

To the extent that the price of our common stock remains at lower levels or it declines further, our ability to raise funds through the issuance of equity or otherwise use our common stock as consideration will be reduced. In addition, increases in our leverage may make it more difficult for us to access additional capital. These factors may limit our ability to implement our operating and growth plans.

Because we have no plans to pay any dividends for the foreseeable future, investors must look solely to stock appreciation for a return on their investment in us.

We have not paid cash dividends on our common stock since our incorporation and our credit facility prohibits us from paying cash dividends on our common stock. We do not anticipate paying any cash dividends in the foreseeable future. We currently intend to retain any future earnings to support our operations and growth. Any payment of cash dividends in the future will be dependent on the amount of funds legally available, our financial condition, capital requirements, ability to pay such dividends under our then existing credit facility and other factors that our board of directors may deem relevant. Accordingly, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize any future gains on their investment.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company at a premium that a stockholder may consider favorable, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company that a stockholder may consider favorable, which could adversely affect the price of our common stock. The provisions in our amended and restated certificate of incorporation and amended and restated bylaws that could delay or prevent an unsolicited change in control of our company include:

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

Future offerings of debt securities, which would rank senior to our common stock in the event of our liquidation, and future offerings of equity securities, which would dilute our existing stockholders or rank senior to our common stock, may adversely affect the market value of our common stock.

We intend to evaluate and may attempt to increase our capital resources by offering debt or equity securities, including commercial paper, medium-term notes, senior or subordinated notes, convertible notes and classes of preferred stock. In the event of our liquidation, holders of our debt securities and preferred stock and lenders with respect to other borrowings will receive a distribution of our available assets prior to the holders of our common stock. Additional equity offerings may dilute the holdings of our existing stockholders or reduce the market value of our common stock, or both. Our preferred stock, if issued, could have a preference on liquidating distributions or a preference on dividend payments that would limit amounts available for distribution to holders of our common stock. Because our decision to issue securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, holders of our common stock bear the risk of our future offerings reducing the market value of our common stock and diluting their shareholdings in us.

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

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

The market price of our common stock could decline as a result of the large number of shares that will become eligible for sale following the expiration of the lock-up period governing the shares of common stock issued on October 1, 2018 in connection with the closing of the transactions contemplated by the Agreement and Plan of Merger between us and Sidewinder Drilling LLC.

A substantial number of additional shares of our common stock are eligible for resale in the public market. Current stockholders of the Company and former shareholders of Sidewinder may not wish to continue to invest in the operations of the combined business after the Sidewinder Merger, or for other reasons, may wish to dispose of some or all of their interests in the Company after the Sidewinder Merger. Sales of substantial numbers of shares of both the newly issued and the existing shares of our common stock in the public market following the expiration of the applicable lock-up period for these shares could adversely affect the market price of our shares of common stock.

Capital, L.P. and MSD Partners, L.P. (the "MSD Parties") own a large percentage of the Company's common stock as a result of the transactions contemplated by the Sidewinder Merger, and will have significant influence over the outcome of corporate actions requiring stockholder approval; such stockholders' priorities for the Company's business may be different from the Company's others stockholders.

The MSD Parties holds approximately 31% of the outstanding shares of the Company's common stock. Although the MSD Parties have agreed in a stockholders' agreement to certain limits on their voting in connection with the election of directors, this limitation will terminate on October 1, 2021, and this limitation does not apply to most other matters that may be submitted by the Company or third parties for stockholder approval. Accordingly, the MSD Parties may be able to significantly influence the outcome of many corporate transactions or other matters submitted to the Company stockholders for approval, including any merger, consolidation or sale of all or substantially all of the Company's assets or any other significant corporate transaction, such that the MSD Parties could potentially delay or prevent a change of control of the Company, even if such a change of control would benefit the Company's other stockholders. The interests of the MSD Parties may differ from the interests of other stockholders.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 2. *PROPERTIES*

We own an approximate 14.4 acre rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas 77086. The complex includes approximately 18,000 square feet of office space and 76,000 square feet of warehouse space. During the third quarter of 2018, as a result of the pending merger with Sidewinder Drilling LLC, management decided to enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in "as-is" condition. As of December 31, 2018, the property is classified as held for sale.

Our operations are managed from field locations that we own or lease, that contain office, shop and yard space to support day-to-day operations, including repair and maintenance of equipment, as well as storage of equipment, materials and supplies. We currently have six such field locations.

Additionally, we lease office space for our corporate headquarters in northwest Houston located at 20475 State Highway 249, Suite 300, Houston, Texas 77070.

We believe that all of our existing properties are suitable for their intended uses and are sufficient to support our operations. We do not believe that any single property is material to our operations and, if necessary, we could obtain a replacement facility. We continuously evaluate the needs of our business, and we will purchase or lease additional properties or reduce our properties, as our business requires.

ITEM 3. *LEGAL PROCEEDINGS*

We are the subject of certain legal proceedings and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such legal proceedings and claims. While the legal proceedings and claims may be asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that the resolution of these matters will have a material adverse effect on our financial position or results of operations. In addition, management monitors our legal proceedings and claims on a quarterly basis and establishes and adjusts any reserves as appropriate to reflect our assessment of the then-current status of such matters.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

PART II

ITEM 5. *MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Market Information for Common Stock

Our common stock is traded on the New York Stock Exchange under the symbol "ICD".

Holders of Record

As of February 25, 2019, we had 77,078,252 shares of common stock outstanding held by approximately 30 holders of record. This number includes registered stockholders and does not include stockholders who hold their shares institutionally.

Dividend Policy

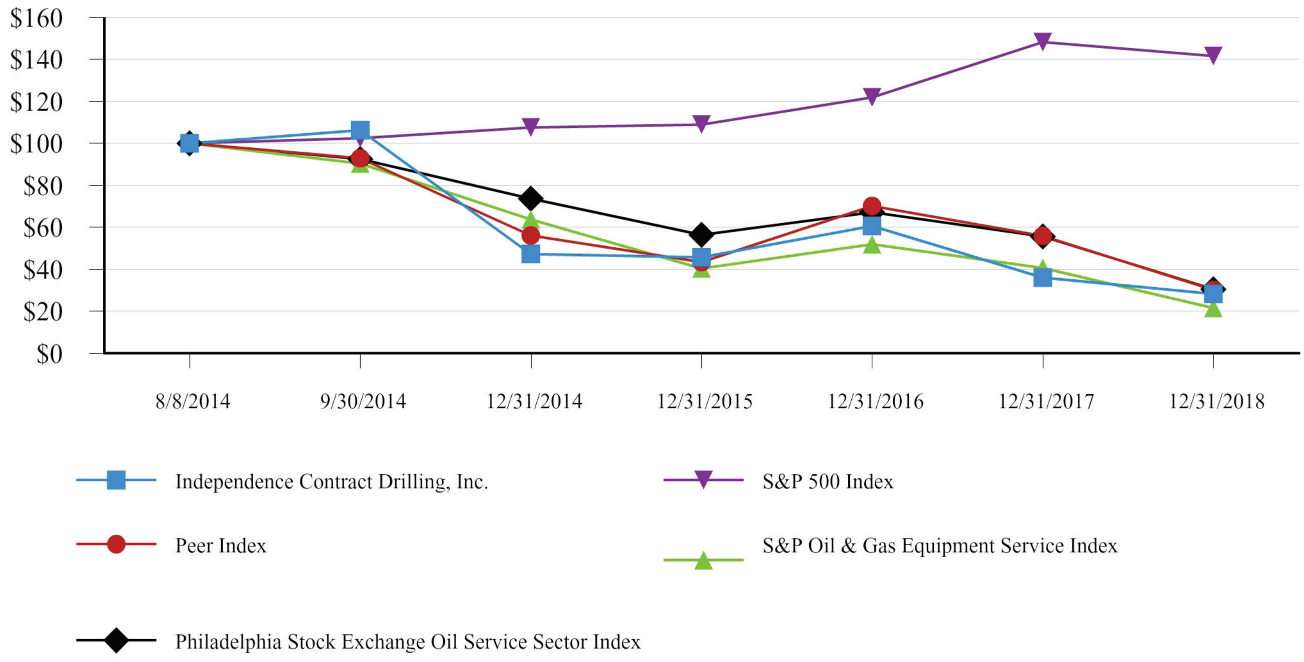
We have not declared or paid any cash dividends on our common stock, our ABL Credit Facility prohibits us from paying cash dividends on our common stock, and we do not currently anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any future determination relating to our dividend policy will be at the discretion of our board of directors and will depend on funds legally available, our results of operations, financial condition, capital requirements, the ability to pay cash dividends under our then existing revolving credit facility and other factors deemed relevant by our board.

Stock Performance Graph

The following stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the "Securities Act"), or the Securities Exchange Act of 1934, as amended (the "Exchange Act"), except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The following graph compares our cumulative total stockholder return during the period from our initial public offering (IPO) on August 7, 2014 to December 31, 2018 with total stockholder return during the same period for the Standard & Poors 500 Index, the Standard & Poors Oil and Gas Equipment Service Index, the Philadelphia Stock Exchange Oil Service Sector Index and an index of peer companies. The graph assumes that (i) $100 was invested in our common stock on August 8, 2014 at our IPO price of $11.00 per share, (ii) $100 was invested in each index on August 8, 2014 at the closing price on such date, and (iii) all dividends, if any, were reinvested.

Stock Performance Graph



	8/8/2014	9/30/2014	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
Independence Contract Drilling, Inc.	$ 100.00	$ 106.24	$ 47.20	$ 45.66	$ 60.58	$ 35.99	$ 28.21
S&P 500 Index	$ 100.00	$ 102.42	$ 107.47	$ 108.91	$ 121.81	$ 148.22	$ 141.51
Peer Index	$ 100.00	$ 92.85	$ 56.16	$ 43.34	$ 70.06	$ 55.87	$ 30.17
S&P Oil & Gas Equipment Service Index	$ 100.00	$ 90.27	$ 63.70	$ 40.34	$ 51.95	$ 40.60	$ 21.50
Philadelphia Stock Exchange Oil Service Sector Index	$ 100.00	$ 92.50	$ 73.65	$ 56.41	$ 67.13	$ 55.58	$ 30.45

The index of peer companies consists of: Helmerich & Payne, Inc., Nabors Industries, Ltd., Patterson-UTI Energy, Inc., Pioneer Energy Services Corp., Precision Drilling Corporation, RPC, Inc., Superior Energy Services, Inc. and Trinidad Drilling Ltd.

Recent Sales of Unregistered Securities; Use of Proceeds from Registered Securities

None.

Issuer Purchases of Equity Securities

During the fourth quarter of 2018, we withheld shares of our common stock to satisfy tax withholding obligations in connection with the vesting of certain stock awards. These shares are deemed to be "issuer purchases" of shares that are required to be disclosed pursuant to this Item but were not purchased as part of a publicly announced program to repurchase common shares. The following table provides information relating to our repurchase of shares of common stock during the three months ended December 31, 2018 (dollars in thousands, except average price paid per share):

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares That May Yet be Purchased Under the Program (1)
October 1 — October 31	175,872	$ 4.71	—	$ —
November 1 — November 30	—	$ —	—	$ —
December 1 — December 31	—	$ —	—	$ —

(1) We do not have a current share repurchase program authorized by the board of directors.

ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth our selected historical financial data. Our selected historical financial data as of and for the periods presented below were derived from our audited consolidated financial statements.

Our historical results are not necessarily indicative of our future operating results. The share information gives effect to a 1.57-for-1 stock split in the form of a stock dividend on July 24, 2014. The selected historical financial data presented below is qualified in its entirety by reference to, and should be read in conjunction with, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related Notes included in "Item 8. Financial Statements and Supplementary Data."

	Year Ended				
(In thousands, except per share data)	December 31, 2018	December 31, 2017	December 31, 2016	December 31, 2015	December 31, 2014
Statement of operations data(1):					
Revenues	$ 142,609	$ 90,007	$ 70,062	$ 88,418	$ 70,347
Operating costs	95,220	67,733	43,277	52,087	42,654
Selling, general and administrative(2)	15,907	13,213	16,144	14,483	12,222
Merger related expenses(3)	13,646	—	—	—	—
Depreciation and amortization	30,891	25,844	23,808	21,151	16,181
Goodwill impairment and other charges(4)	—	—	—	—	30,627
Asset impairments, net (5)	25	2,568	3,822	2,708	1,711
(Gain) loss on disposition of assets, net	(740)	1,677	1,942	2,940	19
Total cost and expenses	154,949	111,035	88,993	93,369	103,414
Operating loss	(12,340)	(21,028)	(18,931)	(4,951)	(33,067)
Interest expense	(7,562)	(2,983)	(3,045)	(3,254)	(1,648)
Gain on warrant derivative(6)	—	—	—	—	3,189
Loss before income taxes	(19,902)	(24,011)	(21,976)	(8,205)	(31,526)
Income tax expense (benefit)	91	287	202	(325)	(3,358)
Net loss	$ (19,993)	$ (24,298)	$ (22,178)	$ (7,880)	$ (28,168)
Weighted-average number of shares outstanding (basic and diluted)	47,580	37,762	33,118	23,904	17,078
Net loss per share (basic and diluted)	$ (0.42)	$ (0.64)	$ (0.67)	$ (0.33)	$ (1.65)
Cash flow data:					
Net cash provided by operating activities	$ 16,135	$ 4,933	$ 16,973	$ 27,379	$ 3,809
Net cash used in investing activities	(25,247)	(30,094)	(20,058)	(72,219)	(112,686)
Net cash provided by financing activities	18,826	20,623	4,812	39,427	116,904
Balance sheet data:					
Total assets	$ 584,862	$ 304,645	$ 302,107	$ 314,789	$ 289,547
Long-term debt	130,012	49,278	26,078	62,708	—
Total liabilities	193,329	69,163	44,855	82,052	52,811
Total stockholders' equity	391,533	235,482	257,252	232,737	236,736

(1) There are no other components of comprehensive income or loss.

(2) For the year ended December 31, 2016, includes a one-time retirement payment of $1.5 million.

(3) Merger related expenses represent costs incurred in connection with the Sidewinder Merger that consist of legal and various other professional fees, $2.6 million of stock-based compensation awards that were accelerated in accordance with the change of control provisions of the awards and severance, including $3.5 million to be paid to our former Chief Executive Officer.

(4) Represents the impairment of goodwill totaling $11.0 million and accelerated amortization of our rig manufacturing intellectual property totaling $19.6 million.

(5) For the year ended December 31, 2018, primarily represents asset impairment expense associated with an increase in the estimated cost to sell the Galayda Facility, offset by insurance recoveries for damage to that facility sustained in Hurricane Harvey during 2017. For the year ended December 31, 2017, primarily represents asset impairment expense associated with the impairment of certain held for sale assets and the impairment of the Galayda Facility as a result of water damage attributable to Hurricane Harvey that affected the Houston area in late August of 2017. For the year ended December 31, 2016, represents asset impairment expense associated with the impairment of certain assets designated as held for sale. For the year ended December 31, 2015, represents asset impairment expense associated with the impairment of various rig components of our last remaining non-walking rig and asset impairment expense associated with damage to a driller's cabin, offset by final insurance recoveries. For the year ended December 31, 2014, represents asset impairment expense associated with damage sustained to the mast and other operating equipment on one of our non-walking rigs, net of insurance claim recoveries. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(6) Represents a non-cash gain associated with the decrease in the estimated fair value of a warrant to purchase 2.2 million shares issued to Global Energy Services, Inc. in the acquisition transaction that was completed in March 2012. The warrant expired unexercised on March 2, 2015.

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

You should read the following discussion and analysis of our financial condition and results of operations together with "Item 6. Selected Financial Data" and the consolidated financial statements and related notes that are included in "Item 8. Financial Statements and Supplementary Data." This discussion contains forward-looking statements based upon current expectations that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including without limitation those described in Cautionary Statement Regarding Forward-Looking Statements and "Item 1A. Risk Factors" or in other parts of this Annual Report on Form 10-K.

Management Overview

We were incorporated in Delaware on November 4, 2011. We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We own and operate a premium fleet comprised of modern, technologically advanced drilling rigs. Our first rig began drilling in May 2012. On October 1, 2018, we completed a merger with Sidewinder Drilling LLC. As a result of this merger, we more than doubled our operating fleet and personnel.

Our rigs currently include 32 marketed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and gas properties, and two idle ShaleDriller rigs that will enter our marketed fleet when planned upgrades are completed.

Our marketed 32 rig fleet includes 29 AC powered ("AC") rigs and three 1500-HP ultra-modern SCR rigs. We plan to convert these three SCR rigs to AC pad-optimal status over the next twelve to 18 months based upon market conditions and customer requirements and the timing of their existing contractual commitments. Our two idle rigs that currently are not included in our marketed fleet include one non-walking 1500-HP AC rig and one 1500-HP SCR that will be converted to AC pad-optimal status prior to entering our fleet. We expect both of these rigs to enter our marketed fleet following their upgrade over the next twelve to 18 months based upon market conditions and customer requirements.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas and Midland, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin and the Haynesville Shale; however, our rigs have previously operated in the Eagle Ford Shale and the Mid-Continent and Eaglebine regions as well.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is historically cyclical and characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Significant Developments

Oil and Natural Gas Prices and Drilling Activity

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration (the "EIA"). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid-fifties in February 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Sidewinder Merger

On July 18, 2018, we, Patriot Saratoga Merger Sub, LLC, a wholly owned subsidiary of ICD ("Merger Sub"), Sidewinder Drilling, LLC ("Sidewinder") and MSD Credit Opportunity Master Fund, L.P., as Members' Representative, entered into a definitive merger agreement (the "Merger Agreement") pursuant to which Merger Sub merged with and into Sidewinder (the "Merger"), with Sidewinder surviving the Merger and becoming a wholly owned subsidiary of the Company. The Merger transaction was completed on October 1, 2018. Pursuant to the terms of the Merger Agreement, Sidewinder Series A members received 36,752,657 shares of our common stock in exchange for 100% of the outstanding Series A Common Units of Sidewinder (the "Series A Common Units"). The Merger was accounted for using the acquisition method of accounting with ICD identified as the accounting acquirer. The Series C Units of Sidewinder were canceled pursuant to the Merger Agreement. See Note 3 to our consolidated financial statements for further discussion of the Sidewinder Merger.

In order to finance (i) a portion of the consideration of the Merger and to pay fees, commissions, severance and other expenses and costs related thereto, (ii) the repayment of a fixed amount of outstanding Sidewinder's first lien notes ($58.5 million), (iii) the repayment of any Sidewinder debt under its revolving credit agreement, (iv) the repayment of our debt under our revolving credit agreement and (v) other transaction expenses, we incurred indebtedness of $130.0 million pursuant to the two new credit facilities discussed in *Liquidity and Capital Resources*.

Amendment to Articles of Incorporation

In connection with the Sidewinder Merger, on October 1, 2018, following approval by our shareholders, we amended our certificate of incorporation to increase the authorized number of shares of Common Stock from 100,000,000 shares to 200,000,000 shares.

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our former corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). This plan of sale was subsequently affected by Hurricane Harvey, which caused substantial water-related damage to the Galayda Facility in August 2017, as well as our entry into a definitive merger agreement with Sidewinder Drilling in July 2018. The following summarizes material financial statement impacts of this plan of sale and associated changes as a result of these matters:

- In connection with our initial decision to sell the Galayda Facility, at June 30, 2017, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our consolidated balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property.

- As a result of water-related damage caused by Hurricane Harvey, in the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million.

- Following an evaluation of the Galayda Facility and our operating plans following Hurricane Harvey, during the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 consolidated balance sheet and recognized insurance recoveries, net of impairments of approximately $208 thousand in our consolidated statement of operations for the three months ended March 31, 2018.

- During the third quarter of 2018, as a result of the pending merger with Sidewinder, management decided to again enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in "as-is" condition for $3.1 million. As a result, the $2.6 million of property, plant and equipment, representing the portion of the Galayda Facility that was classified as held and used, was reclassified as held for sale on our September 30, 2018 consolidated balance sheet and we recognized an impairment charge of $650 thousand representing the difference between the carrying value of the property and the fair value of the property, less costs to sell.

- During the fourth quarter of 2018, we recorded insurance recoveries, net of impairments of $0.6 million on the Galayda Facility water damage incurred during Hurricane Harvey after receiving a proof of loss letter from our insurance carrier, offset by an increased impairment of $0.2 million related to increased estimated costs to sell the Galayda Facility.

Emerging Growth Company

We are an emerging growth company ("EGC") as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the "JOBS Act". We will remain an EGC for up to five years from the date of the completion of our initial public offering (the "IPO") on August 13, 2014, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1.07 billion, (2) the date that we become a "large accelerated filer" as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), which would occur if the market value of our common equity that is held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter or (3) the date on which we have issued more than $1 billion in non-convertible debt during the preceding three-year period.

As an EGC, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not EGCs including, but not limited to:

- not being required to comply with the auditor attestation requirements related to our internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;

- reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements; and

- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

In addition, Section 107 of the JOBS Act provides that an EGC can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards. Under this provision, an EGC can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We have not elected to avail ourselves of the extended transition period available to EGCs, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Our Revenues

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a "daywork" basis, under which we charge a specified rate per day, or "dayrate." The dayrate associated with each of our contracts is a negotiated price determined by the capabilities of the rig, location, depth and complexity of the wells to be drilled, operating conditions, duration of the contract and market conditions. The term of land drilling contracts may be for a defined number of wells or for a fixed time period. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. If a contract is terminated prior to the specified contract term, early termination payments received from the customer are only recognized as revenues when all contractual obligations, such as mitigation requirements, are satisfied. While under contract, our rigs generally earn a reduced rate while the rig is moving between wells or drilling locations, or on standby waiting for the customer. Reimbursements for the purchase of supplies, equipment, trucking 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. 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.

Our Operating Costs

Our operating costs include all expenses associated with operating and maintaining our drilling rigs. Operating costs include all "rig level" expenses such as labor and related payroll costs, repair and maintenance expenses, supplies, workers' compensation and other insurance, ad valorem taxes and equipment rental costs. Also included in our operating costs are certain costs that are not incurred at the "rig level." These costs include expenses directly associated with our operations management team as well as our safety and maintenance personnel who are not directly assigned to our rigs but are responsible for the oversight and support of our operations and safety and maintenance programs across our fleet.

Our operating costs also include costs and expenses associated with construction activities at our Galayda yard location to the extent that construction activities cease or are not continuous. As a result of the significant downturn in industry conditions, we substantially reduced our rig construction activities during the fourth quarter of 2015 and into 2016.

During 2017 and 2016, our operating costs also included approximately $1.1 million and $3.5 million, respectively, of costs associated with the reactivation of idle and standby rigs. These costs include costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other consumables required for the operation of the rigs.

How We Evaluate our Operations

We regularly use a number of financial and operational measures to analyze and evaluate the performance of our business and compensate our employees, including the following:

- *Safety Performance*. Maintaining a strong safety record is a critical component of our business strategy. We measure safety by tracking the total recordable incident rate for our operations. In addition, we closely monitor and measure compliance with our safety policies and procedures, including "near miss" reports and job safety analysis compliance. We believe our Risk-Based HSE management system provides the required control, yet needed flexibility, to conduct all activities safely, efficiently and appropriately.

- *Utilization*. Rig utilization measures the total amount of time that our rigs are earning revenue under a contract during a particular period. We measure utilization by dividing the total number of Operating Days for a rig by the total number of days the rig is available for operation in the applicable calendar period. A rig is available for operation commencing on the earlier of the date it spuds its initial well following construction or when it has been completed and is actively marketed. “Operating Days” represent the total number of days a rig is earning revenue under a contract, beginning when the rig spuds its initial well under the contract and ending with the completion of the rig’s demobilization.

- *Revenue Per Day*. Revenue per day measures the amount of revenue that an operating rig earns on a daily basis during a particular period. We calculate revenue per day by dividing total contract drilling revenue earned during the applicable period by the number of Operating Days in the period. Revenues attributable to costs reimbursed by customers are excluded from this measure.

- *Operating Cost Per Day.* Operating cost per day measures the operating costs incurred on a daily basis during a particular period. We calculate operating cost per day by dividing total operating costs during the applicable period by the number of Operating Days in the period. Operating costs attributable to costs reimbursed by customers are excluded from this measure.

- *Operating Efficiency and Uptime*. Maintaining our rigs’ operational efficiency is a critical component of our business strategy. We measure our operating efficiency by tracking each drilling rig’s unscheduled downtime on a daily, monthly, quarterly and annual basis.

Results of Operations

The following summarizes our financial and operating data for the years ended December 31, 2018, 2017 and 2016:

	Year Ended		
(In thousands, except per share data)	December 31, 2018	December 31, 2017	December 31, 2016
Revenues	$ 142,609	$ 90,007	$ 70,062
Costs and expenses			
Operating costs	95,220	67,733	43,277
Selling, general and administrative	15,907	13,213	16,144
Merger related expenses	13,646	—	—
Depreciation and amortization	30,891	25,844	23,808
Asset impairment, net	25	2,568	3,822
(Gain) loss on disposition of assets, net	(740)	1,677	1,942
Total cost and expenses	154,949	111,035	88,993
Operating loss	(12,340)	(21,028)	(18,931)
Interest expense	(7,562)	(2,983)	(3,045)
Loss before income taxes	(19,902)	(24,011)	(21,976)
Income tax expense	91	287	202
Net loss	$ (19,993)	$ (24,298)	$ (22,178)
Other financial and operating data:			
Number of marketed rigs (end of year)(1)	32	14	14
Rig operating days(2)	6,687	4,707	3,385
Average number of operating rigs(3)	18.32	12.90	9.25
Rig utilization(4)	97.8%	96.0%	73.6%
Average revenue per operating day (5)	$ 20,001	$ 18,137	$ 19,661
Average cost per operating day(6)	$ 13,053	$ 12,899	$ 10,274
Average rig margin per operating day	$ 6,948	$ 5,238	$ 9,387
Oil price per Bbl (6) (end of year)	$ 45.15	$ 60.46	$ 53.75
Natural gas price per Mcf(7) (end of year)	$ 3.25	$ 3.69	$ 3.71

(1) Number of marketed rigs as of December 31, 2018 increased by 18 rigs as compared to the number of marketed rigs as of December 31, 2017. Our 15th ShaleDriller rig was completed and commenced operations during the third quarter of 2018 and we acquired 17 marketed rigs and two idle non-operating rigs requiring upgrade as a result of the Sidewinder Merger in the fourth quarter of 2018.

(2) Rig operating days represent the number of days our rigs are earning revenue under a contract during the period, including days that standby revenues are earned. During the twelve months ended December 31, 2018, 2017 and 2016 there were 4.3, 77.9 and 882.1 operating days in which the Company earned revenue on a standby basis, respectively, including zero, 69.0 and 839.0 standby-without-crew days, respectively.

(3) Average number of operating rigs is calculated by dividing the total number of rig operating days in the period by the total number of calendar days in the period.

(4) Rig utilization is calculated as rig operating days divided by the total number of days our drilling rigs are available during the applicable period.

(5) Average revenue per operating day represents total contract drilling revenues earned during the period divided by rig operating days in the period. Excluded in calculating average revenue per operating day are revenues associated with the reimbursement of out-of-pocket costs paid by customers of $6.8 million, $4.6 million and $3.5 million during the years ended December 31, 2018, 2017 and 2016, respectively, and revenues associated with the amortization of intangible revenue acquired in the Sidewinder Merger of $2.0 million for the year ended December 31, 2018. Included

in calculating average revenue per operating day for the year ended December 31, 2016 were $1.8 million of early termination revenues associated with a contract termination at the end of the first quarter of 2016.

(6) Average cost per operating day represents total operating costs incurred during the period divided by rig operating days in the period. The following costs are excluded in calculating average cost per operating day: (i) out-of-pocket costs reimbursed by customers of $6.8 million, $4.6 million and $3.5 million during the years ended December 31, 2018, 2017 and 2016, respectively, (ii) new crew training costs of $0.1 million, $0.1 million and $0.5 million during the years ended December 31, 2018, 2017 and 2016, respectively, (iii) construction overhead costs expensed due to reduced rig construction activity of $1.0 million, $1.1 million and $1.5 million during the years ended December 31, 2018, 2017 and 2016, respectively, (iv) rig reactivation costs associated with the redeployment of previously stacked rigs, excluding new crew training costs (included in (ii) above), of $1.0 million and $3.0 million during the years ended December 31, 2017 and 2016, respectively, and (v) out-of-pocket expenses of $0.1 million, net of insurance recoveries, during the year ended December 31, 2017.

(7) WTI spot price as reported by the United States Energy Information Administration.

(8) Henry Hub spot price as reported by the United States Energy Information Administration.

Comparison of the years ended December 31, 2018 and 2017

Revenues

Revenues for the year ended December 31, 2018 were $142.6 million, representing a 58.4% increase over revenues for the year ended December 31, 2017 of $90.0 million. This increase was primarily related to the Sidewinder Merger, as revenues associated with Sidewinder amounted to $32.1 million. Additionally, revenues increased as a result of our newly constructed 15th ShaleDriller rig commencing operations during the third quarter of 2018, as well as a full year impact of our 14th ShaleDriller rig. Revenue per operating day increased to $20,001 during 2018 compared to revenue per operating day of $18,137 during 2017. This increase in average revenue per day resulted primarily from higher average day rates as compared to the prior year. Rig operating days totaled 6,687 during 2018, compared to 4,707 during 2017.

Operating Costs

Operating costs for the year ended December 31, 2018 were $95.2 million, representing a 40.6% increase over operating costs for the year ended December 31, 2017 of $67.7 million. This increase was primarily related to the Sidewinder Merger, as operating costs associated with Sidewinder amounted to $20.4 million. Additionally, operating costs increased as a result of our newly constructed 15th ShaleDriller rig commencing operations during the third quarter of 2018, as well as a full year impact of our 14th ShaleDriller rig. The current year increase in operating costs was offset by a reduction in rig reactivation and crew staging costs compared to the prior period which included approximately $1.1 million related to rigs that were reactivated during the first and second quarter of 2017. On a cost per operating day basis, our cost per day increased to $13,053 during 2018, compared to cost per day of $12,899 during 2017. This increase was primarily due to an increase in rig crew labor rates as well as a decrease in the number of rigs operating on a standby-without-crew basis as compared to the prior year.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2018 were $15.9 million, representing a 20.4% increase over selling, general and administrative expenses for the year ended December 31, 2017 of $13.2 million. This increase was primarily related to the Sidewinder Merger, as selling, general and administrative expenses associated with Sidewinder amounted to $2.4 million. Additional increases relate to higher incentive compensation and higher Louisiana franchise tax expense as compared to 2017.

Merger Related Expenses

Merger related expenses represent expenses incurred in connection with the Sidewinder Merger that consist primarily of legal and various other professional fees, $2.6 million of stock-based compensation for awards that were accelerated in accordance with the accelerated vesting provisions of the awards and severance, including $3.5 million to be paid to our former Chief Executive Officer.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2018 was $30.9 million, representing a 19.5% increase compared to $25.8 million for the year ended December 31, 2017. This increase was primarily related to the Sidewinder Merger, as depreciation and amortization expenses associated with Sidewinder amounted to $4.3 million. Additional increases were directly related to the introduction of new drilling rigs constructed or upgraded by us in 2017 and 2018. We begin depreciating our rigs on a straight-line basis when they commence drilling operations.

Asset Impairment, net

Asset impairment expense of $25.0 thousand was recorded for the year ended December 31, 2018, as compared to $2.6 million for the year ended December 31, 2017, primarily related to the plan to sell the Galayda Facility, net of insurance recoveries for the damage to that facility sustained in Hurricane Harvey in 2017. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

Additionally, in 2017, we impaired the entire carrying value, or $1.0 million, related to certain equipment classified as held for sale, as management believed there to be substantial doubt that the third party manufacturer would service and warranty the equipment, and recorded $0.5 million of impairment expense on certain other damaged drilling equipment.

(Gain) Loss on Disposition of Assets

A gain on the disposition of assets totaling $0.7 million was recorded for the year ended December 31, 2018 compared to a loss on the disposition of assets totaling $1.7 million in the prior year comparable period. In the current year period, the gain primarily relates to the sale or disposition of miscellaneous drilling equipment. In the prior year period, the loss related primarily to a loss of $0.8 million on the sale of certain assets classified as held for sale and a $0.8 million loss on the disposal of certain rig components associated with the upgrade of three of our rigs to 7,500 psi mud systems.

Interest Expense

Interest expense was $7.6 million for the year ended December 31, 2018, compared to $3.0 million for the year ended December 31, 2017. The increase relates in part to our new $130.0 term loan facility that was put in place in connection with the Sidewinder merger, as well as increased average borrowings and higher borrowing rates on our previous revolving credit facility, which was used to fund rig construction and upgrade activity during the first three quarters of 2018. We also expensed $0.9 million in unamortized deferred financing charges when we repaid and terminated our previous credit facility on October 1, 2018 in connection with the Sidewinder Merger.

Income Tax Expense

Income tax expense recorded for the year ended December 31, 2018 amounted to $0.1 million compared to $0.3 million for the year ended December 31, 2017. The effective tax rate was 0.5% for the year ended 2018 compared to 1.2% for the year ended 2017. Taxes in both years relate to Louisiana state income tax and Texas margin tax.

Comparison of the years ended December 31, 2017 and 2016

Revenues

Revenues for the year ended December 31, 2017 were $90.0 million, representing a 28.5% increase over revenues for the year ended December 31, 2016 of $70.1 million. This increase was primarily related to an increase in the average number of operating rigs between periods, offset by lower average revenue per operating day. The average number of rigs operating increased to 12.9 during 2017, compared to 9.25 during 2016 and revenue per operating day decreased to $18,137 during 2017 compared to $19,661 during 2016. This decrease in average revenue per day resulted primarily from lower average day rates as compared to the prior year and a higher early termination rate on a rig in 2016.

Operating Costs

Operating costs for the year ended December 31, 2017 were $67.7 million, representing a 56.5% increase over operating costs for the year ended December 31, 2016 of $43.3 million. This increase was related to an increase in the average number of operating rigs between periods and a decrease in the number of rigs operating on a standby-without-crew basis, which incur minimal operating costs. There were 69 standby-without-crew days in 2017, compared to 839 standby-without-crew days in 2016. On a cost per operating day basis, our cost per day increased to $12,899 during 2017, compared to cost per day of $10,274 during 2016. This increase was primarily due to the decrease in the number of rigs operating on a standby-without-crew basis as compared to the prior year. Additionally, during 2017 and 2016, our operating costs also included approximately $1.1 million and $3.5 million, respectively, of costs associated with the reactivation of idle and standby rigs. These costs include costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other consumables required for the operation of the rigs.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2017 were $13.2 million, representing a 18.2% decrease over selling, general and administrative expenses for the year ended December 31, 2016 of $16.1 million. This decrease primarily relates to the recognition of $1.5 million of severance expense in 2016 associated with the departure of our Chief Operating Officer, as well as higher incentive compensation expense in 2016, offset by higher training expenses in 2017.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2017 was $25.8 million, representing a 8.6% increase compared to $23.8 million for the year ended December 31, 2016. This increase was directly related to the introduction of new drilling rigs constructed or upgraded by us in 2016 and 2017. We begin depreciating our rigs on a straight-line basis when they commence drilling operations.

Asset Impairment, net

Asset impairment expense of $2.6 million was recorded for the year ended December 31, 2017, as compared to $3.8 million for the year ended December 31, 2016, primarily related to the plan to sell the Galayda Facility. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

Additionally, in 2017, we impaired the entire carrying value, or $1.0 million, related to certain equipment classified as held for sale, as management believed there to be substantial doubt that the third party manufacturer would service and warranty the equipment, and recorded $0.5 million of impairment expense on certain other damaged drilling equipment.

In 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded an asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to fair value less estimated cost to sell.

Loss on Disposition of Assets

A loss on the disposition of assets totaling $1.7 million was recorded for the year ended December 31, 2017 compared to a loss on the disposition of assets totaling $1.9 million in the prior year comparable period.

During 2017, we upgraded mud pumps on three rigs and as a result disposed of certain related equipment for a loss of $0.8 million. We also sold certain held for sale assets for a loss of $0.8 million. Additionally, there was a net loss of $0.1 million related to the sale or disposition of miscellaneous drilling equipment.

During 2016, we upgraded mud pumps on five rigs and as a result disposed of certain related equipment for $1.8 million. Additionally, there was a net loss of $0.1 million related to the sale or disposition of miscellaneous drilling equipment.

Interest Expense

Interest expense was $3.0 million for the years ended December 31, 2017 and 2016. Credit facility debt balances were higher in 2017, incurring higher interest expense compared to 2016, as our revolving credit facility debt balance was paid down with the proceeds from the secondary offering completed in April 2016. This was offset by higher interest expense in 2016 associated with the write-off of unamortized deferred financing costs as a result of the reduction in the aggregate commitments of our revolving credit facility amended in April 2016 of $0.5 million.

Income Tax Expense

The income tax expense recorded for the year ended December 31, 2017 amounted to $0.3 million compared to income tax expense of $0.2 million for the year ended December 31, 2016. During 2015, we changed our method of calculating our allowable deduction for the Texas margin tax. As a result, we filed an amended tax return in Texas for 2013 to claim a $0.1 million refund. This refund was received in 2016. The effective tax rate was 1.2% for the year ended 2017 compared to 0.9% for the year ended 2016. Taxes in 2017 relate to state taxes. Taxes in 2016 relate to Texas margin tax.

Future Liquidity and Capital Resources

Our liquidity as of December 31, 2018 included approximately $27.7 million of availability under our $40.0 million ABL Credit Facility, based on a borrowing base of $32.8 million, a $15.0 million committed accordion under our existing term loan facility, $12.2 million of cash and $27.2 million of other net working capital.

We expect our future capital and liquidity needs to be related to funding capital expenditures for our planned rig conversions and upgrades, capital spare inventory, operating expenses, maintenance capital expenditures, working capital and general corporate purposes. We believe that our cash and cash equivalents, cash flows from operating activities and borrowings under our ABL Credit Facility will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next twelve months.

You should read "Item 1A Risk Factors" in particular, "Risks Related to Our Liquidity", for additional information regarding risks surrounding our operations and financial liquidity.

Cash Flows

	Year Ended December 31,		
(in thousands)	2018	2017	2016
Net cash provided by operating activities	$ 16,135	$ 4,933	$ 16,973
Net cash used in investing activities	(25,247)	(30,094)	(20,058)
Net cash provided by financing activities	18,826	20,623	4,812
Net increase (decrease) in cash and cash equivalents	$ 9,714	$ (4,538)	$ 1,727

Net Cash Provided By Operating Activities

Cash provided by operating activities was $16.1 million for the year ended December 31, 2018 compared to $4.9 million for the year ended December 31, 2017. Factors affecting changes in operating cash flows are similar to those that impact net earnings, with the exception of non-cash items such as depreciation and amortization, impairments, gains or losses on disposals of assets, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense, accounts payable and accrued liabilities can significantly affect operating cash flows. Cash flows from operating activities during 2018 were higher as a result of a decrease in net loss of $4.3 million, adjusted for non-cash items of $36.6 million, compared to $34.4 million in 2017. Additionally, working capital changes that decreased cash flows from operating activities were $0.4 million in 2018 compared to $5.1 million in 2017.

Cash provided by operating activities was $4.9 million for the year ended December 31, 2017 compared to $17.0 million for the year ended December 31, 2016. Cash flows from operating activities during 2017 were lower as a result of an increase in net loss of $2.1 million, adjusted for non-cash items of $34.4 million, compared to $35.0 million in 2016. This was offset by working capital changes that decreased cash flows from operating activities in 2017 by $5.1 million compared to working capital changes that increased cash flows from operating activities $4.2 million in 2016.

Net Cash Used In Investing Activities

Cash used in investing activities was $25.2 million for the year ended December 31, 2018 compared to $30.1 million for the year ended December 31, 2017. This decrease was primarily related to cash acquired in the Sidewinder Merger of $10.7 million. Other than the merger, our primary investing activities in 2018 related to the construction of our 15th ShaleDriller rig, rig upgrades and maintenance capital expenditures. Cash payments of $37.6 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $1.3 million and proceeds from insurance claims of $0.3 million.

Cash payments during 2018 included approximately $5.3 million associated with equipment purchased in 2017. During 2017, cash payments of $31.3 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $1.3 million.

Cash used in investing activities was $30.1 million for the year ended December 31, 2017 compared to $20.1 million for the year ended December 31, 2016. This increase was attributable to higher maintenance capital expenditures as a result of the increase in operating rigs versus standby-without-crew. Our primary activities in 2017 related to rig upgrades and maintenance capital expenditures. During 2017, cash payments of $31.3 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $1.3 million. Cash payments in 2017 included approximately $6.2 million associated with equipment purchased in 2016. In 2016, cash payments of $21.1 million for capital expenditures were offset by the receipt of insurance proceeds of $0.2 million and proceeds from the sale of property, plant and equipment of $0.9 million.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $18.8 million for the year ended December 31, 2018 compared to $20.6 million for the year ended December 31, 2017. During 2018, in conjunction with the Sidewinder Merger, we entered into a $130.0 million Term Loan Facility (See Note 8 to our consolidated financial statements - Long-term Debt), paid financing costs on the Term Loan Facility of $3.4 million and repaid Sidewinder indebtedness of $58.5 million. Additionally, we made borrowings under our ABL Credit Facility (See Note 8 to our consolidated financial statements - Long-term Debt) of $5.1 million offset by repayments under our ABL Credit Facility of $2.5 million, and borrowings under our CIT Credit Facility of $50.7 million offset by repayments under our CIT Credit Facility of $99.2 million. We also paid financing costs under the ABL Credit Facility of $0.7 million, financing costs under the CIT Credit Facility of $0.1 million, had restricted stock units withheld for taxes paid of $0.7 million, purchased $1.2 million of treasury stock and made payments for capital lease obligations of $0.6 million.

Cash provided by financing activities was $20.6 million for the year ended December 31, 2017 compared to $4.8 million for the year ended December 31, 2016. During 2017, we made borrowings under our CIT Credit Facility of $44.5 million, offset by repayments under our CIT Credit Facility of $21.7 million, had restricted stock units withheld for taxes paid of $0.9 million, paid financing costs associated with the amendment to the CIT Credit Facility of $0.5 million, purchased $0.2 million of treasury stock and made payments for capital lease obligations of $0.6 million. During 2016, we received proceeds of $42.9 million from a public offering and made borrowings under our CIT Credit Facility of $49.0 million, offset by repayments under our CIT Credit Facility of $86.0 million. We paid financing costs associated with the amendment to the CIT Credit Facility of $0.2 million, purchased $0.4 million of treasury stock and made payments for capital lease obligations of $0.5 million.

Long-term Debt

In conjunction with the closing of the Sidewinder Merger on October 1, 2018, we entered into a term loan Credit Agreement (the “Term Loan Credit Agreement”) for an initial term loan in an aggregate principal amount of $130.0 million, (the “Term Loan Facility”) and (b) a delayed draw term loan facility in an aggregate principal amount of up to $15.0 million (the “DDTL Facility”, and together with the Term Loan Facility, the “Term Facilities”). The Term Facilities have a maturity date of October 1, 2023, at which time all outstanding principal under the Term Facilities and other obligations become due and payable in full. Proceeds from the Term Loan Facility were used to repay our existing debt and the Sidewinder debt assumed in the Sidewinder Merger, as well as certain transaction costs.

At our election, interest under the Term Loan Facility is determined by reference at our option to either (i) a “base rate” equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) the London Interbank Offered Rate with an interest period of one month (“LIBOR”), plus 1.0%, and (c) the rate of interest as publicly quoted from time to time by the Wall Street Journal as the “prime rate” in the United States; plus an applicable margin of 6.5%, or (ii) a “LIBOR rate” equal to LIBOR with an interest period of one month, plus an applicable margin of 7.5%.

The Term Loan Credit Agreement contains financial covenants, including a liquidity covenant of $10.0 million and a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability under the ABL Credit Facility (defined below) and the DDTL Facility is below $5.0 million at any time that a DDTL Facility loan is outstanding. The Term Loan Credit Agreement also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The Term Loan Credit Agreement also provides for customary events of default, including breaches of material covenants, defaults under the ABL Credit Facility or other material agreements for indebtedness, and a change of control (as defined).

The obligations under the Term Loan Credit Agreement are secured by a first priority lien on collateral (the "Term Priority Collateral") other than accounts receivable, deposit accounts and other related collateral pledged as first priority collateral ("Priority Collateral") under the ABL Credit Facility (defined below) and a second priority lien on such Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Additionally, in connection with the closing of the Sidewinder Merger on October 1, 2018, we entered into a $40.0 million revolving Credit Agreement (the "ABL Credit Facility"), including availability for letters of credit in an aggregate amount at any time outstanding not to exceed $7.5 million. Availability under the ABL Credit Facility is subject to a borrowing base calculated based on 85% of the net amount of our eligible accounts receivable, minus reserves. The ABL Credit Facility has a maturity date of the earlier of October 1, 2023 or the maturity date of the Term Loan Credit Agreement.

At our election, interest under the ABL Credit Facility is determined by reference at our option to either (i) a "base rate" equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) LIBOR with an interest period of one month, plus 1.0%, and (c) the prime rate of Wells Fargo, plus in each case, an applicable base rate margin ranging from 1.0% to 1.5% based on quarterly availability, or (ii) a revolving loan rate equal to LIBOR for the applicable interest period plus an applicable LIBOR margin ranging from 2.0% to 2.5% based on quarterly availability. We also pay, on a quarterly basis, a commitment fee of 0.375% (or 0.25% at any time when revolver usage is greater than 50% of the maximum credit) per annum on the unused portion of the ABL Credit Facility commitment.

The ABL Credit Facility contains a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability is less than 10% of the maximum credit. The ABL Credit Facility also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The ABL Credit Facility also provides for customary events of default, including breaches of material covenants, defaults under the Term Loan Agreement or other material agreements for indebtedness, and a change of control.

The obligations under the ABL Credit Facility are secured by a first priority lien on Priority Collateral, which includes all accounts receivable and deposit accounts, and a second priority lien on the Term Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Additionally, included in our long-term debt are capital leases. These leases generally have initial terms of 36 months and are paid monthly.

Contractual Obligations

As of December 31, 2018, we had contractual obligations as described below. Our obligations include non-cancelable capital leases, as well as "off-balance sheet arrangements" whereby the liabilities associated with non-cancelable operating leases and unconditional purchase obligations are not fully reflected in our consolidated balance sheets.

(in thousands)	2019	2020	2021	Thereafter	Total
Term Loan Facility	$ —	$ —	$ —	$ 130,000	$ 130,000
ABL Credit Facility	—	—	—	2,566	2,566
Interest on Term Loan Facility	13,199	13,235	13,199	24,217	63,850
Interest on ABL Credit Facility	305	306	305	564	1,480
Lease obligations	1,431	1,014	537	761	3,743
Purchase obligations	16,292	—	—	—	16,292
Total contractual obligations	$ 31,227	$ 14,555	$ 14,041	$ 158,108	$ 217,931

Our long-term debt as of December 31, 2018 consisted of amounts due under our Term Loan Facility and ABL Credit Facility. Interest on long-term debt is related to our estimated future contractual interest obligations on long-term indebtedness outstanding as of December 31, 2018 under our Term Loan Facility and ABL Credit Facility. Interest payment obligations on our Term Loan Facility were estimated based on the 9.9% interest rate that was in effect at December 31, 2018, and the principal balance of $130.0 million at December 31, 2018, and assuming repayment of the outstanding balance occurs at October 1, 2023. Interest payment obligations on our ABL Credit Facility were estimated based on the 6.75% interest rate that was in effect at December 31, 2018, and the principal balance of $2.6 million at December 31, 2018, and assuming repayment of the outstanding balance occurs at October 1, 2023.

We use our incremental borrowing rate at the inception of each capital lease to calculate the interest on the capital leases. Our capital leases relate to certain vehicles and our operating leases relate primarily to real estate and certain vehicles.

Our purchase obligations relate primarily to outstanding purchase orders for rig equipment or components ordered but not received. We have made progress payments on these orders of approximately $2.9 million that could be forfeited if we were to cancel these orders.

Critical Accounting Policies and Accounting Estimates

The consolidated financial statements are impacted by the accounting policies and estimates and assumptions used by management during their preparation. These estimates and assumptions are evaluated on an on-going basis. Estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities if not readily available from other sources. Actual results may differ from these estimates under different assumptions or conditions. The following is a discussion of the critical accounting policies and estimates used in our consolidated financial statements. Other significant accounting policies are summarized in Note 2 to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

Revenue and Cost Recognition

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a “daywork” basis, under which we charge a specified rate per day, or “dayrate.” The dayrate associated with each of our contracts is a negotiated price determined by the capabilities of the rig, location, depth and complexity of the wells to be drilled, operating conditions, duration of the contract and market conditions. The term of land drilling contracts may be for a defined number of wells or for a fixed time period. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied. While under contract, our rigs generally earn a reduced rate while the rig is moving between wells or drilling locations, or on standby waiting for the customer. Reimbursements for the purchase of supplies, equipment, trucking 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. 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.

Our operating costs include all expenses associated with operating and maintaining our drilling rigs. Operating costs include all “rig level” expenses such as labor and related payroll costs, repair and maintenance expenses, supplies, workers' compensation and other insurance, ad valorem taxes and equipment rental costs. Also included in our operating costs are certain costs that are not incurred at the rig level. These costs include expenses directly associated with our operations management team as well as our safety and maintenance personnel who are not directly assigned to our rigs but are responsible for the oversight and support of our operations and safety and maintenance programs across our fleet.

Property, Plant and Equipment

Property, plant and equipment, including renewals and betterments, are stated at cost less accumulated depreciation. All property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets. The cost of maintenance and repairs are expensed as incurred. Major overhauls and upgrades are capitalized and depreciated over their remaining useful life.

Depreciation of property, plant and equipment is recorded based on the estimated useful lives of the assets as follows:

	Estimated Useful Life
Buildings	20 - 39 years
Drilling rigs and related equipment	3 - 20 years
Machinery, equipment and other	3 - 7 years
Vehicles	2 - 5 years

We review our assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The recoverability of assets that are held and used is measured by comparison of the estimated future undiscounted cash flows associated with the asset to the carrying amount of the asset. If the carrying value of such assets is less than the estimated undiscounted cash flow, an impairment charge is recorded in the amount by which the carrying amount of the assets exceeds their estimated fair value. As of December 31, 2018, we determined that there were no conditions that existed that would suggest rig carrying values may not be recoverable.

Asset impairment expense of $25.0 thousand was recorded for 2018, as compared to $2.6 million for 2017, primarily related to the plan to sell the Galayda Facility, net of insurance recoveries for the damage to that facility sustained in Hurricane Harvey in 2017. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

In 2016, we began a review of our rig fleet and other capital equipment with a focus on opportunities to standardize certain rig components across our fleet. The standardization of this equipment creates operating efficiencies in maintaining this equipment, as well as efficiencies when crews transfer between rigs. As a result of our review, we identified several non-standard items which, while fully functional, were less than optimal from an operations perspective. We recorded a non-cash asset impairment charge of $3.8 million in the fourth quarter of 2016, to write down these assets to fair value less estimated cost to sell. Such assets were classified as held for sale on our December 31, 2016 balance sheet. In the second quarter of 2017, we sold $1.6 million of these assets and recognized a loss on the sale of assets of $0.8 million. In the fourth quarter of 2017, we impaired the entire carrying value, or $1.0 million, related to certain of the assets held for sale, for which management believes there is substantial doubt that the third party manufacturer will service and warranty the equipment.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we record deferred income taxes based upon differences between the financial reporting basis and tax basis of assets and liabilities, and use enacted tax rates and laws that we expect will be in effect when we realize those assets or settle those liabilities. We review deferred tax assets for a valuation allowance based upon management’s estimates of whether it is more likely than not that a portion of the deferred tax asset will be fully realized in a future period.

We recognize the financial statement benefit of a tax position only after determining that the relevant taxing authority would more-likely-than-not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the consolidated financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Our policy is to include interest and penalties related to the unrecognized tax benefits within the income tax expense (benefit) line item in our consolidated statement of operations.

Stock-Based Compensation

We record compensation expense over the requisite service period for all stock-based compensation based on the grant date fair value of the award. The expense is included in selling, general and administrative expense in our consolidated statement of operations or capitalized in connection with rig construction activity.

Other Matters

Off-Balance Sheet Arrangements

We are party to certain arrangements defined as “off-balance sheet arrangements” that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. These arrangements relate to non-cancelable operating leases and unconditional purchase obligations not fully reflected on our consolidated balance sheets. See Note 13 to our consolidated financial statements for additional information.

Emerging Growth Company

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of leases with terms of 12 months or less) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. The provisions of this standard also apply to situations where companies are the lessor and therefore it could impact the accounting and related disclosures for our drilling contracts.

In July 2018, the FASB issued ASU No. 2018-11, Leases: Targeted Improvements, which provides an option to apply the guidance prospectively, and provides a practical expedient allowing lessors to combine the lease and non-lease components of revenues where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC Topic 606, Revenue from Contracts with Customers, when the non-lease component is the predominant element of the combined components. We are in the process of evaluating the provisions of ASU No. 2018-11, specifically as they relate to our drilling contracts, but will elect the practical expedient for combining the lease and non-lease components of revenue. We are still evaluating which component is predominant.

We will adopt the new lease guidance effective January 1, 2019 and will elect the optional transition method whereby the initial application of the standard begins on the date of adoption and comparative periods are not restated. We will also elect the transition practical expedient package available in the ASU whereby we will not reassess (i) whether any of our expired or existing contracts are, or contain a lease, (ii) the classification for any expired or existing leases and (iii) initial direct costs for any existing leases.

As a lessee, we cannot yet fully quantify the impact of adoption as we are still analyzing all the acquired leases associated with the Sidewinder Merger that was completed during the fourth quarter of 2018. We do, however, expect our assets and liabilities to increase as a result of recognizing the right-of-use assets and lease liabilities. We are currently in the process of reviewing all relevant Sidewinder contracts and completing the implementation of a lease accounting system to manage our leases and converting our existing lease data to the new system.

In January 2017, the FASB issued ASU No. 2017-04, Intangibles—Goodwill and Other, which simplifies the subsequent measurement of goodwill by eliminating Step 2 of the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under this new standard, an entity should perform its goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and then recognize an impairment charge, as necessary, for the amount by which the carrying amount exceeds the reporting unit’s fair value, not to exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for fiscal years beginning after December 15, 2019. We are currently evaluating the impact this new guidance will have on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for public companies for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We are exposed to a variety of market risks including risks related to potential adverse changes in interest rates and commodity prices. We actively monitor exposure to market risk and continue to develop and utilize appropriate risk management techniques. We do not use derivative financial instruments for trading or to speculate on changes in commodity prices.

Interest Rate Risk

Total long-term debt at December 31, 2018 included $132.6 million of floating-rate debt attributed to borrowings at an average interest rate of 9.84%. As a result, our annual interest cost in 2019 will fluctuate based on short-term interest rates. The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.98%) would be approximately $1.3 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2018; however, there are no assurances that possible rate changes would be limited to such amounts.

Commodity Price Risk

Oil and natural gas prices, and market expectations of potential changes in these prices, significantly impact the level of worldwide drilling and production services activities. Reduced demand for oil and natural gas generally results in lower prices for these commodities and may impact the economics of planned drilling projects and ongoing production projects, resulting in the curtailment, reduction, delay or postponement of such projects for an indeterminate period of time. When drilling and production activity and spending decline, both dayrates and utilization have also historically declined. Further declines in oil and natural gas prices and the general economy, could materially and adversely affect our business, results of operations, financial condition and growth strategy.

In addition, if oil and natural gas prices decline, companies that planned to finance exploration, development or production projects through the capital markets may be forced to curtail, reduce, postpone or delay drilling activities even further, and also may experience an inability to pay suppliers. Adverse conditions in the global economic environment could also impact our vendors' and suppliers' ability to meet obligations to provide materials and services in general. If any of the foregoing were to occur, or if current depressed market conditions continue for a prolonged period of time, it could have a material adverse effect on our business and financial results and our ability to timely and successfully implement our growth strategy.

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration (the "EIA"). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid-fifties in February 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Credit and Capital Market Risk

Our customers may finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as currently being experienced, can make it difficult for our customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices, or a reduction of available financing may result in a reduction in customer spending and the demand for our drilling services. This reduction in spending could have a material adverse effect on our business, financial condition, cash flows, and results of operations.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Independence Contract Drilling, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Independence Contract Drilling, Inc. and its subsidiary (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and financial statement schedule listed in accompanying index (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2015.

Houston, Texas

March 1, 2019

Independence Contract Drilling, Inc.
Consolidated Balance Sheets
(In thousands, except par value and share amounts)

	December 31, 2018	December 31, 2017
Assets		
Cash and cash equivalents	$ 12,247	$ 2,533
Accounts receivable, net	41,987	18,056
Inventories	2,693	2,710
Assets held for sale	19,711	4,637
Prepaid expenses and other current assets	8,930	2,957
Total current assets	85,568	30,893
Property, plant and equipment, net	496,197	272,388
Goodwill	1,627	—
Other long-term assets, net	1,470	1,364
Total assets	$ 584,862	$ 304,645
Liabilities and Stockholders' Equity		
Liabilities		
Current portion of long-term debt	$ 587	$ 533
Accounts payable	16,312	11,627
Accrued liabilities	29,219	6,969
Total current liabilities	46,118	19,129
Long-term debt	130,012	49,278
Deferred income taxes, net	774	683
Other long-term liabilities	16,425	73
Total liabilities	193,329	69,163
Commitments and contingencies (Note 13)		
Stockholders' equity		
Common stock, $0.01 par value, 200,000,000 shares authorized; 77,598,806 and 38,246,919 shares issued, respectively; and 77,078,252 and 37,985,225 shares outstanding, respectively	771	380
Additional paid-in capital	503,446	326,616
Accumulated deficit	(109,638)	(89,645)
Treasury stock, at cost, 520,554 and 261,694 shares, respectively	(3,046)	(1,869)
Total stockholders' equity	391,533	235,482
Total liabilities and stockholders' equity	$ 584,862	$ 304,645

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

Independence Contract Drilling, Inc.
Consolidated Statements of Operations
(In thousands, except per share amounts)

	Year Ended December 31,		
	2018	2017	2016
Revenues	$ 142,609	$ 90,007	$ 70,062
Costs and expenses			
Operating costs	95,220	67,733	43,277
Selling, general and administrative	15,907	13,213	16,144
Merger related expenses	13,646	—	—
Depreciation and amortization	30,891	25,844	23,808
Asset impairment, net	25	2,568	3,822
(Gain) loss on disposition of assets, net	(740)	1,677	1,942
Total cost and expenses	154,949	111,035	88,993
Operating loss	(12,340)	(21,028)	(18,931)
Interest expense	(7,562)	(2,983)	(3,045)
Loss before income taxes	(19,902)	(24,011)	(21,976)
Income tax expense	91	287	202
Net loss	$ (19,993)	$ (24,298)	$ (22,178)
Loss per share:			
Basic and diluted	$ (0.42)	$ (0.64)	$ (0.67)
Weighted-average number of common shares outstanding:			
Basic and diluted	47,580	37,762	33,118

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

Independence Contract Drilling, Inc.
Consolidated Statements of Changes in Stockholders' Equity
(In thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Stockholders' Equity
	Shares	Amount				
Balances at December 31, 2015	24,403,659	$ 244	$ 276,948	$ (43,169)	$ (1,286)	$ 232,737
Restricted stock forfeited	(8,182)	—	—	—	—	—
Restricted stock units vested	74,968	—	—	—	—	—
Purchase of treasury stock	(77,525)	—	—	—	(409)	(409)
Public offering, net of offering costs	13,225,000	132	42,788	—	—	42,920
Stock-based compensation	—	—	4,182	—	—	4,182
Net loss	—	—	—	(22,178)	—	(22,178)
Balances at December 31, 2016	37,617,920	$ 376	$ 323,918	$ (65,347)	$ (1,695)	$ 257,252
Restricted stock forfeited	(3,195)	—	—	—	—	—
RSUs vested, net of shares withheld for taxes	418,391	4	(867)	—	—	(863)
Purchase of treasury stock	(47,891)	—	—	—	(174)	(174)
Stock-based compensation	—	—	3,565	—	—	3,565
Net loss	—	—	—	(24,298)	—	(24,298)
Balances at December 31, 2017	37,985,225	$ 380	$ 326,616	$ (89,645)	$ (1,869)	$ 235,482
Restricted stock issued	1,385,973	14	(14)	—	—	—
RSUs vested, net of shares withheld for taxes	1,213,257	12	(722)	—	—	(710)
Purchase of treasury stock	(258,860)	(3)	—	—	(1,177)	(1,180)
Shares issued in connection with Sidewinder Merger	36,752,657	368	172,737	—	—	173,105
Stock-based compensation	—	—	4,829	—	—	4,829
Net loss	—	—	—	(19,993)	—	(19,993)
Balances at December 31, 2018	**77,078,252**	**$ 771**	**$ 503,446**	**$ (109,638)**	**$ (3,046)**	**$ 391,533**

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

Independence Contract Drilling, Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities			
Net loss	$ (19,993)	$ (24,298)	$ (22,178)
Adjustments to reconcile net loss to net cash provided by operating activities			
Depreciation and amortization	30,891	25,844	23,808
Asset impairment, net	25	2,568	3,822
Stock-based compensation	4,829	3,565	4,249
Stock-based compensation - executive retirement	—	—	(67)
(Gain) loss on disposition of assets, net	(740)	1,677	1,942
Amortization of deferred rent	105	—	—
Deferred income taxes	91	287	203
Amortization of deferred financing costs	492	434	532
Write-off of deferred financing costs	856	—	504
Bad debt expense	22	—	—
Changes in operating assets and liabilities, net of effects of Sidewinder Merger			
Accounts receivable	(1,022)	(6,588)	6,772
Inventories	250	(301)	55
Prepaid expenses and other assets	(4,681)	133	212
Accounts payable and accrued liabilities	5,010	1,612	(2,881)
Net cash provided by operating activities	16,135	4,933	16,973
Cash flows from investing activities			
Cash acquired in Sidewinder Merger	10,743	—	—
Purchases of property, plant and equipment	(37,550)	(31,347)	(21,106)
Proceeds from insurance claims	257	—	188
Proceeds from the sale of assets	1,303	1,253	860
Net cash used in investing activities	(25,247)	(30,094)	(20,058)
Cash flows from financing activities			
Borrowings under Term Loan Facility	130,000	—	—
Borrowings under ABL Credit Facility	5,066	—	—
Borrowings under CIT Credit Facility	50,666	44,451	49,048
Repayments under ABL Credit Facility	(2,500)	—	—
Repayments under CIT Credit Facility	(99,207)	(21,662)	(86,004)
Repayment of Sidewinder debt	(58,512)	—	—
Public offering proceeds, net of offering costs	—	—	42,920
Purchase of treasury stock	(1,180)	(174)	(409)
RSUs withheld for taxes	(710)	(863)	—
Financing costs paid under Term Loan Facility	(3,371)	—	—
Financing costs paid under ABL Credit Facility	(676)	—	—
Financing costs paid under CIT Credit Facility	(114)	(530)	(217)
Payments of capital lease obligations	(636)	(599)	(526)
Net cash provided by financing activities	18,826	20,623	4,812
Net increase (decrease) in cash and cash equivalents	9,714	(4,538)	1,727
Cash and cash equivalents			
Beginning of year	2,533	7,071	5,344
End of year	$ 12,247	$ 2,533	$ 7,071

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

1. Nature of Operations and Recent Developments

Except as expressly stated or the context otherwise requires, the terms “we,” “us,” “our,” the “Company” and “ICD” refer to Independence Contract Drilling, Inc. and its subsidiary.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a premium fleet comprised of modern, technologically advanced drilling rigs. Our fleet currently includes 32 marketed ShaleDriller® rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and gas properties, and two idle ShaleDriller rigs that will enter our marketed fleet when planned upgrades are completed.

Our marketed 32 rig fleet includes 29 AC powered (“AC”) rigs and two 1500-HP ultra-modern SCR rigs. Our two idle rigs that currently are not included in our marketed fleet include one non-walking 1500-HP AC rig and one 1500-HP SCR that will be converted to AC pad-optimal status prior to entering our fleet. We expect both of these rigs to enter our marketed fleet following their upgrade over the next twelve to 18 months based upon market conditions and customer requirements.

We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas and Midland, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin and the Haynesville Shale; however, our rigs have previously operated in the Eagle Ford Shale and the Mid-Continent and Eaglebine regions as well.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is historically cyclical and characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Oil and Natural Gas Prices and Drilling Activity

Oil prices declined from a high of $107.95 per barrel in the second quarter of 2014, to a low of $26.19 per barrel in the first quarter of 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn, with the U.S. land rig count falling from a high of 1930 rigs in 2014 to a low of 404 rigs in 2016. In addition to overall rig count decline, pricing for our contract drilling services also substantially declined during this period of time. Although crude oil prices recovered in 2017 and 2018, reaching a high of $77.41 per barrel in the second quarter of 2018, the U.S. land count never recovered to its 2014 highs, only reaching 1083 rigs the week ending December 28, 2018. Similarly, although pricing improved during this period, pricing never reached rates experienced in 2014.

During the fourth quarter of 2018, oil prices began to decline, reaching a low of $44.48. Although oil prices have recently recovered to the mid fifties in February 2019, most of our E&P customers have decreased planned capital expenditure budgets with the goal of operating within their cash flows, which they expect to be lower in 2019 unless commodity prices substantially improve. These changes have resulted in softening demand for contract drilling services. Although we believe market conditions for our services have stabilized, we believe this stabilization is predicated on oil prices remaining above a $50 per barrel or higher range. If oil prices were to fall below these levels for any sustainable period, demand and pricing for our contract drilling services could decline and have a material adverse affect on our operations and financial condition.

Sidewinder Merger

On July 18, 2018, ICD, Patriot Saratoga Merger Sub, LLC, a wholly owned subsidiary of ICD (“Merger Sub”), Sidewinder Drilling, LLC (“Sidewinder”) and MSD Credit Opportunity Master Fund, L.P., as Members’ Representative, entered into a definitive merger agreement (the “Merger Agreement”) pursuant to which Merger Sub merged with and into Sidewinder (the “Merger”), with Sidewinder surviving the Merger and becoming a wholly owned subsidiary of the ICD. The Merger transaction was completed on October 1, 2018. Pursuant to the terms of the Merger Agreement, Sidewinder Series A members received 36,752,657 shares of ICD common stock in exchange for 100% of the outstanding Series A Common Units of Sidewinder (the “Series A Common Units”). The Merger was accounted for using the acquisition method of accounting with ICD identified as the accounting acquirer. The Series C Units of Sidewinder were canceled pursuant to the Merger Agreement. See Note 3 to our financial statements for further discussion of the Sidewinder Merger.

In order to finance (i) a portion of the consideration of the Merger and to pay fees, commissions, severance and other expenses and costs related thereto, (ii) the repayment of a fixed amount of outstanding Sidewinder’s first lien notes of ($58.5 million), (iii) the repayment of any Sidewinder debt under its revolving credit agreement, (iv) the repayment of our debt under our revolving credit agreement and (v) other transaction expenses, ICD incurred indebtedness of $130.0 million pursuant to the two new Credit Facilities discussed in Note 8 Long-term Debt.

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our former corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). This plan of sale was subsequently affected by Hurricane Harvey, which caused substantial water-related damage to the Galayda Facility in August 2017, as well as our entry into a definitive merger agreement with Sidewinder Drilling in July 2018. The following summarizes material financial statement impacts of this plan of sale and associated changes as result of these matters:

- In connection with our initial decision to sell the Galayda Facility, at June 30, 2017, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our consolidated balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property.

- As a result of water-related damage caused by Hurricane Harvey, in the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million.

- Following an evaluation of the Galayda Facility and our operating plans following Hurricane Harvey, during the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 consolidated balance sheet and recognized insurance recoveries, net of impairments of approximately $208 thousand in our consolidated statement of operations for the three months ended March 31, 2018.

- During the third quarter of 2018, as a result of the pending merger with Sidewinder, management decided to again enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in “as-is” condition for $3.1 million. As a result, the $2.6 million of property, plant and equipment, representing the portion of the Galayda Facility that was classified as held and used, was reclassified as held for sale on our September 30, 2018 consolidated balance sheet and we recognized an impairment charge of $650 thousand representing the difference between the carrying value of the property and the fair value of the property, less costs to sell.

- During the fourth quarter of 2018, we recorded insurance recoveries, net of impairments of $0.6 million on the Galayda Facility water damage incurred during Hurricane Harvey after receiving a proof of loss letter from our insurance carrier, offset by an increased impairment of $0.2 million related to increased estimated costs to sell the Galayda Facility.

2. Summary of Significant Accounting Policies

Basis of Presentation

These audited consolidated financial statements include all the accounts of ICD and its subsidiary. All significant intercompany accounts and transactions have been eliminated. Except for the subsidiary, we have no controlling financial interests in any other entity which would require consolidation. These audited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). As we had no items of other comprehensive income in any period presented, no other comprehensive income is presented.

Cash and Cash Equivalents

We consider short-term, highly liquid investments that have an original maturity of three months or less to be cash equivalents.

Accounts Receivable

Accounts receivable is comprised primarily of amounts due from our customers for contract drilling services. Accounts receivable are reduced to reflect estimated realizable values by an allowance for doubtful accounts based on historical collection experience and specific review of current individual accounts. Receivables are written off when they are deemed to be uncollectible. Allowance for doubtful accounts was zero as of December 31, 2018 and was $8 thousand as of December 31, 2017.

Inventories

Inventory is stated at lower of cost or net realizable value and consists primarily of supplies held for use in our drilling operations. Cost is determined on an average cost basis.

Property, Plant and Equipment, net

Property, plant and equipment, including renewals and betterments, are stated at cost less accumulated depreciation. All property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets. The cost of maintenance and repairs are expensed as incurred. Major overhauls and upgrades are capitalized and depreciated over their remaining useful life.

Depreciation of property, plant and equipment is recorded based on the estimated useful lives of the assets as follows:

	Estimated Useful Life
Buildings	20 - 39 years
Drilling rigs and related equipment	3 - 20 years
Machinery, equipment and other	3 - 7 years
Vehicles	2 - 5 years

We own an approximate 14.4 acre rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas 77086. During the third quarter of 2018, as a result of the pending merger with Sidewinder Drilling LLC, management decided to enter into a plan to sell the entire Galayda Facility and entered into an agreement with a third-party buyer to sell the Galayda Facility in "as-is" condition. As of December 31, 2018, the property is classified as held for sale.

Our operations are managed from field locations that we own or lease, that contain office, shop and yard space to support day-to-day operations, including repair and maintenance of equipment, as well as storage of equipment, materials and supplies. We currently have six such field locations.

Additionally, we lease office space for our corporate headquarters in northwest Houston located at 20475 State Highway 249, Suite 300, Houston, Texas 77070. Leases are evaluated at inception or at any subsequent material modification to determine if the lease should be classified as a capital or operating lease.

We review our assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The recoverability of assets that are held and used is measured by comparison of the estimated future undiscounted cash flows associated with the asset to the carrying amount of the asset. If the carrying value of such assets is less than the estimated undiscounted cash flow, an impairment charge is recorded in the amount by which the carrying amount of the assets exceeds their estimated fair value.

Construction in progress represents the costs incurred for drilling rigs and rig upgrades under construction at the end of the period. This includes third party costs relating to the purchase of rig components as well as labor, material and other identifiable direct and indirect costs associated with the construction of the rig.

Capitalized Interest

We capitalize interest costs related to rig construction projects. Interest costs are capitalized during the construction period based on the weighted-average interest rate of the related debt. Capitalized interest amounted to $0.2 million, $0.1 million and $0.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Financial Instruments and Fair value

Fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, there exists a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1 Unadjusted quoted market prices for identical assets or liabilities in an active market;

Level 2 Quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets; and

Level 3 Unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date

This hierarchy requires us to use observable market data, when available, and to minimize the use of unobservable inputs when determining fair value.

The carrying value of certain of our assets and liabilities, consisting primarily of cash and cash equivalents, accounts receivable, accounts payable and certain accrued liabilities approximates their fair value due to the short-term nature of such instruments.

The fair value of our long-term debt is determined by Level 3 measurements based on quoted market prices and terms for similar instruments, where available, and on the amount of future cash flows associated with the debt, discounted using our current borrowing rate for comparable debt instruments (the Income Method). Based on our evaluation of the risk free rate, the market yield and credit spreads on comparable company publicly traded debt issues, we used an annualized discount rate, including a credit valuation allowance, of 10.1%. The fair value of our capital lease obligations is determined using Level 3 measurements using our current incremental borrowing rate. The estimated fair value of our long-term debt totaled $134.9 million and $50.6 million as of December 31, 2018 and 2017, respectively, compared to a carrying amount of $133.2 million and $49.3 million as of December 31, 2018 and 2017, respectively. The following table summarizes the carrying value and fair value of our long-term debt as of December 31, 2018 and 2017.

	December 31, 2018		December 31, 2017	
(in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan Facility	$ 130,000	$ 131,893	$ —	$ —
ABL Credit Facility	2,566	2,258	—	—
CIT Credit Facility	—	—	48,541	49,871
Long-term capital leases	648	759	737	747
	133,214	$ 134,910	49,278	$ 50,618
Less: Term Loan Facility deferred financing costs	(3,202)		—	
	$ 130,012		$ 49,278	

The fair value of our assets held for sale is determined using Level 3 measurements. Fair value measurements are applied with respect to our non-financial assets and liabilities measured on a nonrecurring basis, which would consist of measurements primarily of long-lived assets. There were no transfers between levels of the hierarchy for the years ended December 31, 2018 and 2017.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net assets acquired in connection with the Sidewinder Merger. Goodwill is not amortized, but rather tested and assessed for impairment annually in the third quarter of each year, or more frequently if certain events or changes in circumstance indicate that the carrying amount may exceed fair value. We initially begin with a qualitative assessment of whether it is “more likely than not” that the fair value of one of our reporting units is less than its carrying value. If the carrying amount exceeds the fair value, an impairment charge will be recognized in an amount equal to the excess; however, the loss recognized would not exceed the total amount of goodwill allocated to that reporting unit.

Intangible Liabilities

Intangible liabilities were recorded in connection with the Sidewinder Merger for drilling contracts in place at the closing date of the transaction that had unfavorable contract terms as compared to current market terms for comparable drilling rigs. The various factors considered in the determination are (1) the contracted day rate for each contract, (2) the remaining term of each contract, (3) the rig class and (4) the market conditions for each respective rig at the transaction closing date. The intangible liabilities were computed based on the present value of the differences in cash inflows over the remaining contract term as compared to a hypothetical contract with the same remaining term at an estimated current market day rate using a risk-adjusted discount rate. The intangible liabilities are amortized to operating revenues over the remaining underlying contract terms. The remaining terms of these contracts as of December 31, 2018 range from 0 to 7 months, with a weighted-average term of approximately 3 months.

The following table summarizes the components of intangible liabilities, net:

	December 31,	
(in thousands)	**2018**	**2017**
Intangible liabilities	$ 3,123	$ —
Accumulated amortization	(2,044)	—
Intangible liabilities, net	$ 1,079	$ —

The intangible liabilities, net are classified in our consolidated balance sheet under the caption accrued liabilities.

Revenue and Cost Recognition

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a “daywork” basis, under which we charge a specified rate per day, or “dayrate.” The dayrate associated with each of our contracts is a negotiated price determined by the capabilities of the rig, location, depth and complexity of the wells to be drilled, operating conditions, duration of the contract and market conditions. The term of land drilling contracts may be for a defined number of wells or for a fixed time period. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied. While under contract, our rigs generally earn a reduced rate while the rig is moving between wells or drilling locations, or on standby waiting for the customer. Reimbursements for the purchase of supplies, equipment, trucking 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. 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.

Our operating costs include all expenses associated with operating and maintaining our drilling rigs. Operating costs include all “rig level” expenses such as labor and related payroll costs, repair and maintenance expenses, supplies, workers' compensation and other insurance, ad valorem taxes and equipment rental costs. Also included in our operating costs are certain costs that are not incurred at the rig level. These costs include expenses directly associated with our operations management team as well as our safety and maintenance personnel who are not directly assigned to our rigs but are responsible for the oversight and support of our operations and safety and maintenance programs across our fleet.

In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). We adopted ASU 2014-09 and its related amendments (collectively known as ASC 606) effective on January 1, 2018 using the modified retrospective method. While ASC 606 requires additional disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, its adoption did not have a material impact on the measurement or recognition of our revenues. The amount of demobilization revenue that we collect, if any, is dependent upon the specific contract terms, which generally include provisions for reduced (or no) payment for demobilization when, among other things, the contract is renewed or extended, or when the rig is contracted with another client prior to the termination of the current contract. Since revenues associated with demobilization activity are typically variable, at each period end, they are estimated at the most likely amount, and constrained when the likelihood of a significant reversal is probable.

See Note 4 "Revenue from Contracts with Customers" for the required disclosures related to the impact of adopting this standard and a discussion of our policies related to revenue recognition and accounting for costs to obtain and fulfill a customer contract.

Stock-Based Compensation

We record compensation expense over the requisite service period for all stock-based compensation based on the grant date fair value of the award. The expense is included in selling, general and administrative expense in our statements of operations or capitalized in connection with rig construction activity.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we record deferred income taxes based upon differences between the financial reporting basis and tax basis of assets and liabilities, and use enacted tax rates and laws that we expect will be in effect when we realize those assets or settle those liabilities. We review deferred tax assets for a valuation allowance based upon management’s estimates of whether it is more likely than not that a portion of the deferred tax asset will be fully realized in a future period.

We recognize the financial statement benefit of a tax position only after determining that the relevant taxing authority would more-likely-than-not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the consolidated financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Our policy is to include interest and penalties related to the unrecognized tax benefits within the income tax expense (benefit) line item in our statements of operations.

Use of Estimates

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the balance sheet date, and the reported amounts of revenues and expenses recognized during the reporting period. Actual results could differ from these estimates. Significant estimates made by management include depreciation of property, plant and equipment, impairment of property, plant and equipment, the collectibility of accounts receivable and the fair value of the assets acquired and liabilities assumed in connection with the Sidewinder Merger.

Other Matters

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of leases with terms of 12 months or less) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. The provisions of this standard also apply to situations where companies are the lessor and therefore it could impact the accounting and related disclosures for our drilling contracts.

In July 2018, the FASB issued ASU No. 2018-11, Leases: Targeted Improvements, which provides an option to apply the guidance prospectively, and provides a practical expedient allowing lessors to combine the lease and non-lease components of revenues where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The practical expedient also allows a lessor to account for the combined lease and non-lease components under ASC Topic 606, Revenue from Contracts with Customers, when the non-lease component is the predominant element of the combined components. We are in the process of evaluating the provisions of ASU No. 2018-11, specifically as they relate to our drilling contracts, but will elect the practical expedient for combining the lease and non-lease components of revenue. We are still evaluating which component is predominant.

We will adopt the new lease guidance effective January 1, 2019 and will elect the optional transition method whereby the initial application of the standard begins on the date of adoption and comparative periods are not restated. We will also elect the transition practical expedient package available in the ASU whereby we will not reassess (i) whether any of our expired or existing contracts are, or contain a lease, (ii) the classification for any expired or existing leases and (iii) initial direct costs for any existing leases.

As a lessee, we cannot yet fully quantify the impact of adoption as we are still analyzing all the acquired leases associated with the Sidewinder Merger that was completed during the fourth quarter of 2018. We do, however, expect our assets and liabilities to increase as a result of recognizing the right-of-use assets and lease liabilities. We are currently in the process of reviewing all relevant Sidewinder contracts and completing the implementation of a lease accounting system to manage our leases and converting our existing lease data to the new system.

In January 2017, the FASB issued ASU No. 2017-04, Intangibles—Goodwill and Other, which simplifies the subsequent measurement of goodwill by eliminating Step 2 of the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under this new standard, an entity should perform its goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and then recognize an impairment charge, as necessary, for the amount by which the carrying amount exceeds the reporting unit’s fair value, not to exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for fiscal years beginning after December 15, 2019. We are currently evaluating the impact this new guidance will have on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for public companies for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

3. Sidewinder Merger

We completed the Sidewinder Merger on October 1, 2018, through an exchange of 100% of Sidewinder's outstanding voting interests for 36,752,657 shares of ICD common stock. The Sidewinder Merger was accounted for using the acquisition method of accounting with ICD identified as the accounting acquirer.

Sidewinder owns 15 AC drilling rigs and four modern 1500-HP SCR rigs, each marketed or operating in the Permian or Haynesville plays. Sidewinder also owns four smaller 1000-HP SCR rigs and one smaller 1000-HP AC rig, which ICD will use for spare equipment and does not intend to market following the Sidewinder Merger. The transaction combined two pad-optimal drilling fleets focused in the Permian basin, Haynesville region and other basins in Texas and its contiguous states, and more than doubled the size of our pad-optimal fleet to 32 rigs, following upgrades to five Sidewinder rigs.

In addition, Sidewinder owns 11 mechanical rigs and related equipment (the "Mechanical Rigs") located in the Utica and Marcellus plays. As these rigs are not consistent with ICD's core strategy or geographic focus, ICD has agreed that these rigs can be disposed of, with the Sidewinder unitholders receiving the net proceeds. Thus, in addition to the shares of ICD common stock issued at the closing of the transaction, the Sidewinder Series A Members are entitled to receive such member's share of any Mechanical Rig Net Sales (as defined by the Merger Agreement), payable in accordance with the Merger Agreement to the extent such proceeds were not either used to repay certain Sidewinder indebtedness or paid as a dividend to the Sidewinder members prior to the closing of the Sidewinder Merger. As a result of this arrangement, we recorded $15.9 million, representing the fair value of the Mechanical Rigs less costs to sell, as assets held for sale, with an offsetting liability in contingent consideration at the closing of the transaction.

Consideration Transferred

The fair value of the consideration transferred to effect the acquisition of Sidewinder was as follows:

(in thousands, except share price)		
Equity consideration:		
Number of shares of ICD common stock issued		36,753
ICD common share price on October 1, 2018	$	4.71
Equity consideration	$	173,105
Other consideration:		
Sidewinder indebtedness assumed and repaid by ICD	$	58,512
Consideration transferred	$	231,617

Preliminary Allocation of Consideration Transferred to Assets Acquired and Liabilities Assumed

The following amounts represents the preliminary estimates of the fair value of assets acquired and liabilities assumed in connection with the Sidewinder Merger transaction. Certain elements of the preliminary purchase price allocation are based on actuarial or other management estimates that may be refined over time. We do not expect the final amounts to differ materially from current estimates. We expect to finalize the allocation of purchase price to the assets acquired and liabilities assumed during 2019.

(in thousands)		
Cash	$	10,743
Other current assets		23,496
Assets held for sale		16,427
Property, plant and equipment		215,284
Other long-term assets		343
Total assets acquired		266,293
Accounts payable and accrued liabilities		(17,278)
Unfavorable contract liabilities		(3,123)
Contingent consideration		(15,902)
Net assets acquired		229,990
Goodwill		1,627
Total consideration transferred	$	231,617

Supplemental Pro Forma Financial Information

Sidewinder's results of operations have been included in ICD's consolidated financial statements for the period subsequent to the closing of the acquisition on October 1, 2018. Sidewinder contributed revenues of approximately $32.1 million and operating income of approximately $3.3 million for the period from October 1, 2018 through December 31, 2018.

The following supplemental pro forma results of operations assume that Sidewinder had been acquired on January 1, 2017. The supplemental pro forma financial information was prepared based on the historical financial information of

Sidewinder and ICD and has been adjusted to give effect to pro forma adjustments that are both directly attributable to the transaction and factually supportable. The pro forma amounts reflect certain adjustments to revenues, depreciation and amortization and interest expense. It also excludes the results of operations for the 11 mechanical rigs that are part of the combined business after following the Sidewinder Merger transaction. The pro forma results for the year ended December 31, 2018 reflect adjustments to exclude the merger related costs incurred by Sidewinder and ICD totaling $15.3 million:

	Year Ended December 31, (Unaudited)	
(in thousands, except per share amounts)	**2018**	**2017**
Revenue	$ 228,036	$ 184,697
Net loss	$ (17,498)	$ (46,134)
Loss per share	$ (0.23)	$ (0.62)

4. Revenue from Contracts with Customers

Effective January 1, 2018, we adopted Accounting Standards Codification ("ASC") Revenue from Contracts with Customers ("ASC 606"), using the modified retrospective method. This standard applies to all contracts with customers, except for contracts that are within the scope of other standards, such as leases, insurance, collaborative arrangements and financial instruments. Under ASC 606, an entity recognizes revenue when it transfers control of the promised goods or services to its customer, in an amount that reflects the consideration which the entity expects to receive in exchange for those goods or services. If control transfers to the customer over time, an entity selects a method to measure progress that is consistent with the objective of depicting its performance.

In determining the appropriate amount of revenue to be recognized as we fulfill our obligations under the agreement, the following steps must be performed at contract inception: (i) identification of the promised goods or services in the contract; (ii) determination of whether the promised goods or services are performance obligations, including whether they are distinct in the context of the contract; (iii) measurement of the transaction price, including the constraint on variable consideration; (iv) allocation of the transaction price to the performance obligations; and (v) recognition of revenue when (or as) we satisfy each performance obligation.

Drilling Services

Our revenues are principally derived from contract drilling services and the activities in our drilling contracts, for which revenues may be earned, include: (i) providing a drilling rig and the crews and supplies necessary to operate the rig; (ii) mobilizing and demobilizing the rig to and from the initial and final drill site, respectively; (iii) certain reimbursable activities; (iv) performing rig modification activities required for the contract; and (v) early termination revenues. We account for these integrated services provided under our drilling contracts as a single performance obligation, satisfied over time, that is comprised of a series of distinct time increments. Consideration for activities that are not distinct within the context of our contracts, and that do not correspond to a distinct time increment within the contract term, are allocated across the single performance obligation and recognized ratably in proportion to the actual services performed over the initial term of the contract. If taxes are required to be collected from customers relating to our drilling services, they are excluded from revenue.

Dayrate Drilling Revenue. Our drilling contracts provide that revenue is earned based on a specified rate per day for the activity performed. The majority of revenue earned under daywork contracts is variable, and depends on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term. Such rates generally include the full operating rate, moving rate, standby rate, and force majeure rate and determination of the rate per time increment is made based on the actual circumstances as they occur. Other variable consideration under these contracts could include reduced revenue related to downtime, delays or moving caps.

Mobilization/Demobilization Revenue. We may receive fees (on either a fixed lump-sum or variable dayrate basis) for the mobilization and demobilization of our rigs. These activities are not considered to be distinct within the context of the contract and therefore, the associated revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract. We record a contract liability for mobilization fees received, which is amortized ratably to revenue as services are rendered over the initial term of the related drilling contract. Demobilization fee revenue expected to be received upon contract completion is estimated as part of the overall transaction price at contract inception and recognized in earnings ratably over the initial term of the contract with an offset to an accretive contract asset.

In our contracts, there is generally significant uncertainty as to the amount of demobilization fee revenue that may ultimately be collected due to contractual provisions which stipulate that certain conditions be present at contract completion for such revenue to be received. For example, the amount collectible may be reduced to zero if the rig has been contracted with a new customer upon contract completion. Accordingly, the estimate for such revenue may be constrained depending on the facts and circumstances pertaining to the specific contract. We assess the likelihood of receiving such revenue based on past experience and knowledge of the market conditions.

Reimbursable Revenue. We receive reimbursements from our customers for the purchase of supplies, equipment and other services provided at their request in accordance with a drilling contract or other agreement. Such reimbursable revenue is variable and subject to uncertainty, as the amounts received and timing thereof is highly dependent on factors outside of our influence. Accordingly, reimbursable revenue is fully constrained and not included in the total transaction price until the uncertainty is resolved, which typically occurs when the related costs are incurred on behalf of a customer. We are generally considered a principal in such transactions and record the associated revenue at the gross amount billed to the customer.

Capital Modification Revenue. From time to time, we may receive fees (on either a fixed lump-sum or variable dayrate basis) from our customers for capital improvements to our rigs to meet their requirements. Such revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract, as these activities are not considered to be distinct within the context of our contracts. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract.

Early Termination Revenue. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied.

Intangible Revenue. Intangible liabilities were recorded in connection with the Sidewinder Merger for drilling contracts in place at the closing date of the transaction that had unfavorable contract terms as compared to current market terms for comparable drilling rigs. The various factors considered in the determination are (1) the contracted day rate for each contract, (2) the remaining term of each contract, (3) the rig class and (4) the market conditions for each respective rig at the transaction closing date. The intangible liabilities were computed based on the present value of the differences in cash inflows over the remaining contract term as compared to a hypothetical contract with the same remaining term at an estimated current market day rate using a risk adjusted discount rate. The intangible liabilities are amortized to operating revenues over the remaining underlying contract terms.

Disaggregation of Revenue

The following table summarizes revenues from our contracts disaggregated by revenue generating activity contained therein for the years ended December 31, 2018, 2017 and 2016:

(in thousands)	2018	2017	2016
Dayrate drilling	$ 133,278	$ 84,834	$ 60,383
Mobilization	2,100	2,235	2,228
Reimbursables	4,970	2,828	1,990
Capital modification	216	91	5,433
Intangible	2,044	—	—
Other	1	19	28
Total revenue	$ 142,609	$ 90,007	$ 70,062

Contract Balances

Accounts receivable are recognized when the right to consideration becomes unconditional based upon contractual billing schedules. Payment terms on invoiced amounts are typically 30 days. Contract asset balances could consist of demobilization fee revenue that we expect to receive that is recognized ratably throughout the contract term, but invoiced upon completion of the demobilization activities. Once the demobilization fee revenue is invoiced the corresponding contract asset is transferred to accounts receivable. Contract liabilities include payments received for mobilization fees as well as upgrade activities, which are allocated to the overall performance obligation and recognized ratably over the initial term of the contract.

The following table provides information about receivables, contract assets and contract liabilities related to contracts with customers:

(in thousands)	**December 31, 2018**	**December 31, 2017**
Receivables, which are included in "Accounts receivable, net"	$ 41,988	$ 18,028
Contract assets	$ —	$ —
Contract liabilities	$ (1,374)	$ (836)

Significant changes in contract assets and contract liabilities balances during 2018 are as follows:

	2018	
(in thousands)	**Contract Assets**	**Contract Liabilities**
Revenue recognized that was included in contract liabilities at beginning of period	$ —	$ 763
Increase in contract liabilities due to cash received, excluding amounts recognized as revenue	$ —	$ (1,301)
Transferred to receivables from contract assets at beginning of period	$ —	$ —

Transaction Price Allocated to the Remaining Performance Obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) as of December 31, 2018. The estimated revenue does not include amounts of variable consideration that are constrained.

	Year Ending December 31,			
(in thousands)	**2019**	**2020**	**2021**	**Total**
Revenue	$ (1,374)	$ —	$ —	$ (1,374)

The amounts presented in the table above consist only of fixed consideration related to fees for rig mobilizations and demobilizations, if applicable, which are allocated to the drilling services performance obligation as such performance obligation is satisfied. We have elected the exemption from disclosure of remaining performance obligations for variable consideration. Therefore, dayrate revenue to be earned on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term and other variable consideration such as penalties and reimbursable revenues, have been excluded from the disclosure.

Contract Costs

We capitalize costs incurred to fulfill our contracts that (i) relate directly to the contract, (ii) are expected to generate resources that will be used to satisfy our performance obligations under the contract and (iii) are expected to be recovered through revenue generated under the contract. These costs, which principally relate to rig mobilization costs at the commencement of a new contract, are deferred as a current or noncurrent asset (depending on the length of the contract term), and amortized ratably to contract drilling expense as services are rendered over the initial term of the related drilling contract. Such contract costs, recorded as "Prepaid expenses and other current assets", amounted to $1.1 million and $0.8 million on our consolidated balance sheets at December 31, 2018 and December 31, 2017, respectively. During the year ended December 31, 2018, contract costs increased by $1.7 million and we amortized $1.4 million of contract costs.

Costs incurred for the demobilization of rigs at contract completion are recognized as incurred during the demobilization process. Costs incurred for rig modifications or upgrades required for a contract, which are considered to be capital improvements, are capitalized as drilling and other property and equipment and depreciated over the estimated useful life of the improvement.

Impact of ASC 606 on Consolidated Financial Statement Line Items

The timing of our revenue recognition under ASC 606 is similar to revenue recognition under the previous guidance, except for the recognition of demobilization fee revenue, which we earn infrequently. Such revenue, which was recognized upon completion of a contract under the previous guidance, will now be estimated at contract inception and recognized as contract drilling revenue as the drilling services performance obligation is satisfied, subject to constraint, with an offset to a contract asset. As we had no existing contracts as of January 1, 2018, where we expect to receive a demobilization fee from our customers, there was no cumulative effect of a change in accounting principle required to adjust our January 1, 2018 retained earnings.

5. Inventories

Inventories consisted of the following:

	December 31,	
(in thousands)	**2018**	**2017**
Rig components and supplies	$ 2,693	$ 2,710

We determined that no reserve for obsolescence was needed at December 31, 2018 or 2017. No inventory obsolescence expense was recognized during the years ended December 31, 2018, 2017 and 2016.

6. Property, Plant and Equipment

Major classes of property, plant, and equipment, which include capital lease assets, consisted of the following (in millions):

	December 31,	
(in thousands)	**2018**	**2017**
Land	$ 487	$ —
Buildings	3,317	—
Drilling rigs and related equipment	594,871	332,338
Machinery, equipment and other	693	2,064
Capital leases	2,027	1,786
Vehicles	533	555
Construction in progress	7,736	20,706
Total	$ 609,664	$ 357,449
Less: Accumulated depreciation	(113,467)	(85,061)
Total Property, plant and equipment, net	$ 496,197	$ 272,388

Repairs and maintenance expense included in operating costs in our statements of operations totaled $19.7 million, $14.3 million and $7.7 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Depreciation expense was $30.9 million, $25.8 million and $23.8 million for the years ended December 31, 2018, 2017 and 2016, respectively.

As of December 31, 2018, property, plant and equipment in our consolidated balance sheets included $2.0 million of vehicles under capital lease, net of $0.7 million of accumulated amortization. As of December 31, 2017, property, plant and equipment in our consolidated balance sheets included $1.8 million of vehicles under capital lease, net of $0.5 million of accumulated amortization.

During the second quarter of 2017, our management committed to a plan to sell our former corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). This plan of sale was subsequently affected by Hurricane Harvey, which caused substantial water-related damage to the Galayda Facility in August 2017, as well as our entry into a definitive merger agreement with Sidewinder Drilling in July 2018. See "Change in Plan of Sale of Assets" in Significant Developments in this Management's Discussion and Analysis.

During 2017 and 2016, we recorded an additional $0.8 million and $1.8 million, respectively, loss on disposal associated with the upgrade of the mud systems on our rigs to high pressure status.

7. Supplemental Consolidated Balance Sheet and Cash Flow Information

Accrued liabilities consisted of the following:

	December 31,	
(in thousands)	**2018**	**2017**
Accrued salaries and other compensation[(1)]	$ 12,379	$ 2,442
Insurance[(2)]	5,464	711
Deferred revenue	1,374	762
Property taxes and other	3,829	2,693
Intangible liability	1,079	—
Interest[(3)]	3,318	95
Other	1,776	266
	$ 29,219	$ 6,969

(1) The increase is primarily attributable to the Sidewinder Merger, increased incentive compensation accruals, and accrued severance related to the Sidewinder Merger, including $3.5 million to be paid to our former Chief Executive Officer.

(2) The increase is primarily attributable to the Sidewinder Merger, in part, as Sidewinder was self-insured for worker’s compensation and general liability insurance prior to the close of the transaction.

(3) The increase is attributable to the Sidewinder Merger and is related to accrued interest on the new $130.0 million Term Loan Facility.

Other long-term liabilities as of December 31, 2018 included $15.7 million of contingent consideration acquired in the Sidewinder Merger. See Note 3 to our consolidated financial statements for further discussion of the Sidewinder Merger.

Supplemental consolidated cash flow information:

(in thousands)	Year Ended December 31, 2018	2017	2016
Supplemental disclosure of cash flow information			
Cash paid during the year for interest	$ 3,202	$ 2,680	$ 2,198
Cash paid (received) during the year for income taxes	$ —	$ —	$ (133)
Supplemental disclosure of non-cash investing and financing activities			
Change in property, plant and equipment purchases in accounts payable	$ 1,175	$ (882)	$ 1,670
Additions to property, plant & equipment through capital leases	$ 601	$ 1,102	$ 1,293
Additions to property, plant and equipment through tenant allowance on leasehold improvement	$ 694	$ —	$ —
Sidewinder Merger consideration	$ 231,617	$ —	$ —

8. Long-term Debt

Our Long-term Debt consisted of the following:

(in thousands)	December 31, 2018	2017
Term Loan Facility due October 1, 2023	$ 130,000	$ —
ABL Credit Facility due October 1, 2023	2,566	—
CIT Credit Facility due November 5, 2020	—	48,541
Capital lease obligations	1,235	1,270
	133,801	49,811
Less: current portion	(587)	(533)
Less: Term Loan Facility deferred financing costs	(3,202)	—
Long-term debt	$ 130,012	$ 49,278

New Credit Facilities

In conjunction with the closing of the Sidewinder Merger on October 1, 2018, we entered into a term loan Credit Agreement (the "Term Loan Credit Agreement") for an initial term loan in an aggregate principal amount of $130.0 million, (the "Term Loan Facility") and (b) a delayed draw term loan facility in an aggregate principal amount of up to $15.0 million (the "DDTL Facility", and together with the Term Loan Facility, the "Term Facilities"). The Term Facilities have a maturity date of October 1, 2023, at which time all outstanding principal under the Term Facilities and other obligations become due and payable in full. Proceeds from the Term Loan Facility were used to repay our existing debt and the Sidewinder debt assumed in the Sidewinder Merger, as well as certain transaction costs.

At our election, interest under the Term Loan Facility is determined by reference at our option to either (i) a "base rate" equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) the London Interbank Offered Rate with an interest period of one month ("LIBOR"), plus 1.0%, and (c) the rate of interest as publicly quoted from time to time by the Wall Street Journal as the "prime rate" in the United States; plus an applicable margin of 6.5%, or (ii) a "LIBOR rate" equal to LIBOR with an interest period of one month, plus an applicable margin of 7.5%.

The Term Loan Credit Agreement contains financial covenants, including a liquidity covenant of $10.0 million and a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability under the ABL Credit Facility (defined below) and the DDTL Facility is below $5.0 million at any time that a DDTL Facility loan is outstanding. The Term Loan Credit Agreement also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The Term Loan Credit Agreement also provides for customary events of default, including breaches of material covenants, defaults under the ABL Credit Facility or other material agreements for indebtedness, and a change of control (as defined).

The obligations under the Term Loan Credit Agreement are secured by a first priority lien on collateral (the "Term Priority Collateral") other than accounts receivable, deposit accounts and other related collateral pledged as first priority collateral ("Priority Collateral") under the ABL Credit Facility (defined below) and a second priority lien on such Priority

Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries. MSD PCOF Partners IV, LLC (an affiliate of MSD Partners) is the lender of our $130.0 million Term Loan Facility. MSD Partners own approximately 31% of the outstanding shares of the Company's common stock.

Additionally, in connection with the closing of the Sidewinder Merger on October 1, 2018, we entered into a $40.0 million revolving Credit Agreement (the "ABL Credit Facility"), including availability for letters of credit in an aggregate amount at any time outstanding not to exceed $7.5 million. Availability under the ABL Credit Facility is subject to a borrowing base calculated based on 85% of the net amount of our eligible accounts receivable, minus reserves. The ABL Credit Facility has a maturity date of the earlier of October 1, 2023 or the maturity date of the Term Loan Credit Agreement.

At our election, interest under the ABL Credit Facility is determined by reference at our option to either (i) a "base rate" equal to the higher of (a) the federal funds effective rate plus 0.05%, (b) LIBOR with an interest period of one month, plus 1.0%, and (c) the prime rate of Wells Fargo, plus in each case, an applicable base rate margin ranging from 1.0% to 1.5% based on quarterly availability, or (ii) a revolving loan rate equal to LIBOR for the applicable interest period plus an applicable LIBOR margin ranging from 2.0% to 2.5% based on quarterly availability. We also pay, on a quarterly basis, a commitment fee of 0.375% (or 0.25% at any time when revolver usage is greater than 50% of the maximum credit) per annum on the unused portion of the ABL Credit Facility commitment.

The ABL Credit Facility contains a springing fixed charge coverage ratio covenant of 1.00 to 1.00 that is tested when availability is less than 10% of the maximum credit. The ABL Credit Facility also contains other customary affirmative and negative covenants, including limitations on indebtedness, liens, fundamental changes, asset dispositions, restricted payments, investments and transactions with affiliates. The ABL Credit Facility also provides for customary events of default, including breaches of material covenants, defaults under the Term Loan Agreement or other material agreements for indebtedness, and a change of control. We are in compliance with our covenants as of December 31, 2018.

The obligations under the ABL Credit Facility are secured by a first priority lien on Priority Collateral, which includes all accounts receivable and deposit accounts, and a second priority lien on the Term Priority Collateral, and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries. On October 1, 2018, in connection with our entry into the ABL Credit Facility, we repaid all outstanding borrowings and obligations under our existing CIT Credit Facility (defined below), and terminated it. As of December 31, 2018, the weighted-average interest rate on our borrowings was 9.84%. At December 31, 2018, the borrowing base under our ABL Credit Facility was $32.8 million, and we had $27.7 million of availability remaining of our $40.0 million commitment on that date.

The CIT Credit Facility

Our CIT Credit Facility (the "CIT Credit Facility"), which was repaid and terminated on October 1, 2018, had a maturity date of November 5, 2020 and provided for aggregate commitments of $85.0 million. We had $67.9 million in outstanding borrowings and $17.1 million of remaining availability under the CIT Credit Facility when it was repaid and terminated.

Borrowings under the CIT Credit Facility were subject to a borrowing base formula that allowed for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the "advance rate", of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. The obligations under the CIT Credit Facility were secured by all of our assets and were unconditionally guaranteed by all of our direct and indirect subsidiaries. At our election, interest under the CIT Credit Facility was determined by reference, at our option, to either (i) the London Interbank Offered Rate ("LIBOR"), plus 4.5% or (ii) a "base rate" equal to the higher of the prime rate published by JP Morgan Chase Bank or three-month LIBOR plus 1%, plus in each case, 3.5%, the federal funds effective rate plus 0.05%. We also paid, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment.

9. Income Taxes

The components of the income tax expense are as follows:

	Year Ended December 31,		
(in thousands)	2018	2017	2016
Current:			
Federal	$ —	$ —	$ —
State	—	—	(1)
	$ —	$ —	$ (1)
Deferred:			
Federal	$ —	$ —	$ —
State	91	287	203
	$ 91	$ 287	$ 203
Income tax expense	$ 91	$ 287	$ 202

The following is a reconciliation of the income tax expense that was recorded compared to taxes provided at the United States statutory rate:

	Year Ended December 31,		
(in thousands)	2018	2017	2016
Income tax benefit at the statutory federal rate (21%, 35% and 35%)	$ (4,233)	$ (8,404)	$ (7,691)
Effect of federal rate change to ending deferred tax assets and liabilities	—	7,994	—
Nondeductible expenses	(270)	34	23
Valuation allowance	3,625	(1,377)	7,063
State taxes, net of federal benefit	14	9	204
Stock-based compensation and other	955	2,031	603
Income tax expense	$ 91	$ 287	$ 202
Effective tax rate	0.5%	1.2%	0.9%

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities are as follows:

	December 31,	
(in thousands)	**2018**	**2017**
Deferred income tax assets		
Merger related expenses	$ 1,731	$ —
Bad debts	—	2
Stock-based compensation	809	1,344
Accrued liabilities and other	1,295	29
Deferred revenue	321	180
Net operating losses	34,682	29,274
Total net deferred tax assets	$ 38,838	$ 30,829
Deferred income tax liabilities		
Prepaids	$ (1,027)	$ (210)
Property, plant and equipment	(22,525)	(18,906)
Intangible assets	(38)	—
Total net deferred tax liabilities	$ (23,590)	$ (19,116)
Valuation allowance	$ (16,022)	$ (12,396)
Net deferred tax liability	$ (774)	$ (683)

As of December 31, 2018, we had a total of $163.9 million of net operating loss carryforwards, of which $131.4 million will begin to expire in 2031 and $26.7 million will be carried forward indefinitely.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the Tax Cuts and Jobs Act (the "Act"), resulting in significant modifications to existing law. We have completed the accounting for the effects of the Act during 2018. Our consolidated financial statements for the year ended December 31, 2018, reflect the effects of the Act which includes a reduction in the corporate tax rate from 35% to 21%. Accordingly, our deferred tax assets and liabilities were revalued at the newly enacted rates expected to be effective in 2018 and forward. Since our federal deferred tax asset was fully offset by a valuation allowance, the overall net adjustment to our tax provision due to the reduction in the U.S. corporate income tax rate to 21% did not materially affect our financial statements.

Section 382 of the Internal Revenue Code ("Section 382") imposes limitations on a corporation's ability to utilize its NOLs if it experiences an ownership change. In general terms, an ownership change may result from transactions increasing the ownership percentage of certain shareholders in the stock of the corporation by more than 50 percentage points over a three year period. In the event of an ownership change, utilization of the NOLs would be subject to an annual limitation under Section 382. The Company believes it incurred an ownership change in April 2016 and in connection with the Sidewinder Merger. The Company is subject to an annual limitation on the usage of its NOL, however, the Company also believes that substantially all of the NOL that existed in April 2016, as well as at the time of the Sidewinder Merger, will be fully available to the Company over the life of the NOL carryforward period. Management will continue to monitor the potential impact of Section 382 with respect to its NOL carryforward.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2018, we had no unrecognized tax benefits. We file income tax returns in the United States and in various state jurisdictions. With few exceptions, we are subject to United States federal, state and local income tax examinations by tax authorities for tax periods 2012 and forward. Our federal and state tax returns for 2012 and subsequent years remain subject to examination by tax authorities. Although we cannot predict the outcome of future tax examinations, we do not anticipate that the ultimate resolution of these examinations will have a material impact on our financial position, results of operations, or cash flows.

In assessing the realizability of the deferred tax assets, we consider whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. In all years presented, we determined that the deferred tax assets did not meet the more likely than not threshold of being utilized and thus recorded a valuation allowance. All of our deferred tax liability as of December 31, 2018 relates to state taxes.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the consolidated statement of operations. We have not recorded any interest or penalties associated with unrecognized tax benefits.

10. Stock-Based Compensation

In March 2012, we adopted the 2012 Omnibus Long-Term Incentive Plan (the "2012 Plan") providing for common stock-based awards to employees and to non-employee directors. The 2012 plan was subsequently amended in August 2014 and June 2016. The 2012 Plan, as amended, permits the granting of various types of awards, including stock options, restricted stock and restricted stock unit awards, and up to 4,754,000 shares were authorized for issuance. Restricted stock and restricted stock units may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options expire ten years after the grant date. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. As of December 31, 2018, approximately 164,999 shares were available for future awards.

In the first quarter of 2017, we adopted ASU 2016-09, Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB issued this accounting standard in an effort to simplify the accounting for employee share-based payments and improve the usefulness of the information provided to users of financial statements. Our policy is to account for forfeitures of share-based compensation awards as they occur.

A summary of compensation cost recognized for stock-based payment arrangements is as follows:

	Year Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Compensation cost recognized:			
Stock options	$ —	$ —	$ 81
Restricted stock and restricted stock units	4,829	3,565	4,101
Total stock-based compensation	$ 4,829	$ 3,565	$ 4,182

Stock Options

Prior to 2016, we granted stock options that remain outstanding. No options were exercised or granted during the years ended December 31, 2018, 2017 or 2016. It is our policy that in the future any shares issued upon option exercise will be issued initially from any available treasury shares or otherwise as newly issued shares.

We use the Black-Scholes option pricing model to estimate the fair value of stock options granted to employees and non-employee directors. The fair value of the options is amortized to compensation expense on a straight-line basis over the requisite service periods of the stock awards, which are generally the vesting periods.

The following summary reflects the stock option activity and related information for the year ended December 31, 2018:

	Options	Weighted Average Exercise Price
Outstanding at January 1, 2018	682,950	$ 12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	(13,737)	12.74
Outstanding at December 31, 2018	669,213	$ 12.74
Exercisable at December 31, 2018	669,213	$ 12.74

The number of options exercisable at December 31, 2018 was 669,213 with a weighted-average remaining contractual life of 3.3 years and a weighted-average exercise price of $12.74 per share.

As of December 31, 2018, there was no unrecognized compensation cost related to outstanding stock options. The fair value of options that vested during the years ended December 31, 2018, 2017 and 2016 was zero, zero, and $0.1 million, respectively.

Time-Based Restricted Stock and Restricted Stock Units

We have granted time-based restricted stock and restricted stock units to key employees under the 2012 Plan. In 2018, this included grants of restricted stock and restricted stock units to four former executives of Sidewinder Drilling, LLC relating to their becoming officers of ICD following the Sidewinder Merger.

Time-based Restricted Stock

Time-based restricted stock awards consist of grants of our common stock that vest ratably over three to five years. We recognize compensation expense on a straight-line basis over the vesting period. The fair value of time-based restricted stock awards is determined based on the estimated fair market value of our shares on the grant date. As of December 31, 2018, there was $4.4 million in unrecognized compensation cost related to unvested time-based restricted stock awards. This cost is expected to be recognized over a weighted-average period of 2.5 years

A summary of the status of our time-based restricted stock awards and of changes in our time-based restricted stock awards outstanding for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2016	388,265	$ 10.80
Granted	—	—
Vested	(232,715)	10.87
Forfeited/expired	(8,182)	11.15
Outstanding at January 1, 2017	147,368	10.67
Granted	—	—
Vested	(144,173)	10.72
Forfeited/expired	(3,195)	8.35
Outstanding at January 1, 2018	—	—
Granted – Former Sidewinder executives[(1)]	646,646	3.22
Granted – Other	739,327	3.22
Vested	—	
Forfeited/expired	—	
Outstanding at December 31, 2018	1,385,973	$ 3.22

(1) Time-based restricted stock granted to former executives of Sidewinder Drilling, LLC relating to their becoming officers of ICD following the Sidewinder Merger.

Time-Based Restricted Stock Units

We have granted three-year time vested restricted stock unit awards where each unit represents the right to receive, at the end of a vesting period, one share of ICD common stock with no exercise price. The fair value of time-based restricted stock unit awards is determined based on the estimated fair market value of our shares on the grant date. As of December 31, 2018, there was $1.8 million of total unrecognized compensation cost related to unvested time-based restricted stock unit awards. This cost is expected to be recognized over a weighted-average period of 1.4 years.

A summary of the status of our time-based restricted stock unit awards and of changes in our time-based restricted stock unit awards outstanding for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2016	123,628	$ 11.00
Granted	747,500	4.00
Vested and converted	(19,768)	6.28
Forfeited/expired	(135,911)	4.60
Outstanding at January 1, 2017	715,449	5.03
Granted	489,862	5.77
Vested and converted	(270,143)	6.05
Forfeited/expired	(146,172)	5.51
Outstanding at January 1, 2018	788,996	5.05
Granted – Former Sidewinder executives(1)	409,607	4.79
Granted – Other	414,521	4.46
Vested and converted	(1,020,423)	4.91
Forfeited/expired	(183,094)	4.50
Outstanding at December 31, 2018	409,607	$ 4.79

(1) Time-based restricted stock unit awards granted to former executives of Sidewinder Drilling, LLC relating to their becoming officers of ICD following the Sidewinder Merger.

Performance-Based and Market-Based Restricted Stock Units

We have granted three-year performance-based and market-based restricted stock unit awards, where each unit represents the right to receive, at the end of a vesting period, up to two shares of ICD common stock with no exercise price. Exercisability of the market-based restricted stock unit awards is based on our total shareholder return ("TSR") as measured against the TSR of a defined peer group and vesting of the performance-based restricted stock unit awards is based on our cumulative EBITDA, safety or uptime performance statistics, as defined in the restricted stock unit agreement, over a three-year period. We used a Monte Carlo simulation model to value the TSR market-based restricted stock unit awards. The fair value of the performance-based restricted stock unit awards is based on the market price of our common stock on the date of grant. During the restriction period, the performance-based and market-based restricted stock unit awards may not be transferred or encumbered, and the recipient does not receive dividend equivalents or have voting rights until the units vest. All performance-based restricted stock units that had not already been earned or vested in accordance with their terms, were forfeited and expired as a result of the consummation of the Sidewinder Merger. As of December 31, 2018, there was no unrecognized compensation cost related to unvested performance-based or market-based restricted stock unit awards.

The assumptions used to value our TSR market-based restricted stock unit awards granted during the year ended December 31, 2016 were a risk-free interest rate of 0.93%, an expected volatility of 56.3% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these restricted stock unit awards were valued at $4.15.

The assumptions used to value our TSR market-based restricted stock unit awards granted during the year ended December 31, 2017 were a risk-free interest rate of 1.30%, an expected volatility of 55.5% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these restricted stock unit awards were valued at $5.62.

The assumptions used to value our TSR market-based restricted stock unit awards granted during the year ended December 31, 2018 were a risk-free interest rate of 2.13%, an expected volatility of 60.6% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these restricted stock unit awards were valued at $5.23.

A summary of the status of our performance-based and market-based restricted stock unit awards and of changes in our restricted stock unit awards outstanding for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Shares	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2016	339,785	$ 13.69
Granted	66,670	4.15
Vested and converted	(46,677)	13.98
Forfeited/expired	(44,569)	10.60
Outstanding at January 1, 2017	315,209	12.07
Granted	166,769	5.71
Vested and converted	(80,752)	16.48
Forfeited/expired	(196,903)	11.84
Outstanding at January 1, 2018	204,323	5.35
Granted	226,520	4.72
Vested and converted	(162,938)	5.04
Forfeited/expired	(267,905)	5.00
Outstanding at December 31, 2018	—	$ —

11. Stockholders' Equity and Loss per Share

As of December 31, 2018, we had a total of 77,078,252 shares of common stock, $0.01 par value, outstanding, including 1,385,973 shares of restricted stock. We also had 520,554 shares held as treasury stock. Total authorized common stock is 200,000,000 shares.

On April 26, 2016, we completed an underwritten public offering of 13,225,000 shares of common stock at a price to the public of $3.50 per share. We received net proceeds of approximately $42.9 million, after deducting underwriting discounts and commissions and offering expenses.

Basic earnings (loss) per common share ("EPS") are computed by dividing income (loss) available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock. A reconciliation of the numerators and denominators of the basic and diluted losses per share computations is as follows:

	For the Years Ended December 31,		
(in thousands, except for per share data)	2018	2017	2016
Net loss (numerator)	$ (19,993)	$ (24,298)	$ (22,178)
Loss per share:			
Basic and diluted	$ (0.42)	$ (0.64)	$ (0.67)
Shares (denominator):			
Weighted-average number of shares outstanding-basic	47,580	37,762	33,118
Net effect of dilutive stock options and restricted stock units	—	—	—
Weighted-average common shares outstanding-diluted	47,580	37,762	33,118

For all years presented, the computation of diluted loss per share excludes the effect of certain outstanding stock options, warrants and restricted stock units because their inclusion would be anti-dilutive. The number of options that were excluded from diluted loss per share were 669,213, 682,950 and 935,720 during the years ended December 31, 2018, 2017 and 2016, respectively. RSUs, which are not participating securities and are excluded from our diluted loss per share because they are anti-dilutive were 409,607, 993,320 and 1,030,658 for the years ended December 31, 2018, 2017 and 2016, respectively.

12. Segment and Geographical Information

We report one segment because all of our drilling operations are all located in the United States and have similar economic characteristics. We build rigs and engage in land contract drilling for oil and natural gas in the United States. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by rig; however, financial performance is measured as a single enterprise and not on a rig-by-rig basis. Allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas.

13. Commitments and Contingencies

Purchase Commitments

As of December 31, 2018, we had outstanding purchase commitments to a number of suppliers totaling $16.3 million related primarily to the construction of drilling rigs and rig upgrades. We have paid deposits of $2.9 million related to these commitments.

Letters of Credit

As of December 31, 2018, we had outstanding letters of credit totaling $2.6 million as collateral for Sidewinder’s pre-acquisition insurance programs. As of December 31, 2018, no amounts had been drawn under these letters of credit.

Lease Commitments

We lease certain land, equipment and vehicles under non-cancelable operating and capital leases. Future minimum lease payments under operating and capital lease commitments, with lease terms in excess of one year subsequent to December 31, 2018, were as follows:

(in thousands)		
2019	$	1,431
2020		1,014
2021		537
2022		360
2023		370
Thereafter		31
	$	3,743

Rent expense was $5.1 million, $3.9 million, and $2.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Employment Agreements

We have entered into employment agreements with two key executives, with original terms of three years, that automatically extend a year prior to expiration, provided that neither party has provided a written notice of termination before that date. These agreements provide for aggregate minimum annual cash compensation of $0.8 million and aggregate cash severance payments totaling $3.0 million for termination by ICD without cause, or termination by the employee for good reason, both as defined in the agreements.

We also have entered into change of control agreements with five key executives, with original terms of three years that automatically extend a year prior to expiration, provided that neither party has provided a written notice of termination before that date. These agreements provide for aggregate cash severance payments totaling $2.3 million for termination by ICD without cause, or termination by the employee for good reason, both as defined in the agreements, if such termination occurs during the three-year period following a change of control, or up to $2.0 million irrespective of whether a change of control has occurred, if such termination occurs on or prior to September 30, 2021.

Contingencies

Our operations inherently expose us to various liabilities and exposures that could result in third party lawsuits, claims and other causes of action. While we insure against the risk of these proceedings to the extent deemed prudent by our management, we can offer no assurance that the type or value of this insurance will meet the liabilities that may arise from any pending or future legal proceedings related to our business activities. There are no current legal proceedings that we expect will have a material adverse impact on our consolidated financial statements.

14. Concentration of Market and Credit Risk

We derive all our revenues from drilling services contracts with companies in the oil and natural gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility in oil and natural gas prices. We have a number of customers that account for 10% or more of our revenues. For 2018, these customers included GeoSouthern Energy Corporation (23%) and COG Operating, LLC, a subsidiary of Concho Resources, Inc. (22%). For 2017, these customers included GeoSouthern Energy Corporation (23%), Devon Energy (17%), RSP Permian, LLC (16%) and Pioneer Natural Resources USA, Inc. (11%). For 2016, these customers included Parsley Energy, LP (22%), Silver Hill Energy Partners, LLC (17%), Pioneer Natural Resources USA, Inc. (16%) and Anadarko Petroleum Corporation (11%).

As of December 31, 2018, COG Operating, LLC, a subsidiary of Concho Resources, Inc. (14%), Diamondback Energy, Inc. (14%), GeoSouthern Energy Corporation (12%) and BP p.l.c (10%) accounted for 10% or more of our accounts receivable. As of December 31, 2017, GeoSouthern Energy Corporation (25%), Devon Energy (20%), RSP Permian, LLC (19%), BHP Billiton Petroleum (15%) and Pioneer Natural Resources USA, Inc. (14%) accounted for 10% or more of our accounts receivable. As of December 31, 2016, Parsley Energy, LP (20%), Pioneer Natural Resources USA, Inc. (19%), GEP Haynesville, LLC (17%), Energen Corporation (16%), Anadarko Petroleum Corporation (14%) and Silver Hill Energy Partners, LLC (14%) accounted for 10% or more of our accounts receivable.

We have concentrated credit risk for cash by maintaining deposits in major banks, which may at times exceed amounts covered by insurance provided by the United States Federal Deposit Insurance Corporation (“FDIC”). We monitor the financial health of the banks and have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk. As of December 31, 2018, we had approximately $11.7 million in cash and cash equivalents in excess of FDIC limits. Our trade receivables are with a variety of E&P and other oilfield service companies. We perform ongoing credit evaluations of our customers, and we generally do not require collateral. We do occasionally require deposits from customers whose creditworthiness is in question prior to providing services to them.

15. Unaudited Quarterly Financial Data

A summary of our unaudited quarterly financial data is as follows:

	Year Ended December 31, 2018			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31[(1)]
Revenue	$ 25,627	$ 25,754	$ 28,439	$ 62,789
Operating loss	(3,252)	(2,396)	(2,819)	(3,873)
Income tax (benefit) expense	(49)	(21)	(50)	211
Net loss	(4,146)	(3,313)	(3,937)	(8,597)
Loss per share:				
Basic and diluted	$ (0.11)	$ (0.09)	$ (0.10)	$ (0.11)

	Year Ended December 31, 2017			
	Quarter Ended			
(in thousands, except for per share data)	March 31	June 30	September 30	December 31
Revenue	$ 20,236	$ 21,285	$ 23,445	$ 25,041
Operating loss	(5,593)	(5,584)	(5,178)	(4,673)
Income tax expense	46	34	30	177
Net loss	(6,269)	(6,304)	(5,980)	(5,745)
Loss per share:				
Basic and diluted	$ (0.17)	$ (0.17)	$ (0.16)	$ (0.15)

(1) Includes the operations of Sidewinder beginning on October 1, 2018.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in thousands)	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
Year Ended December 31, 2018:				
Allowance for doubtful accounts	$ 8	$ 22	$ (30)	$ —
Valuation allowance for deferred tax assets	$ 12,396	$ 3,626	$ —	$ 16,022
Year Ended December 31, 2017:				
Allowance for doubtful accounts	$ 8	$ —	$ —	$ 8
Valuation allowance for deferred tax assets	$ 13,773	$ (1,377)	$ —	$ 12,396
Year Ended December 31, 2016:				
Allowance for doubtful accounts	$ 8	$ —	$ —	$ 8
Valuation allowance for deferred tax assets	$ 6,710	$ 7,063	$ —	$ 13,773

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures were effective as of December 31, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of our internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the 2013 framework). Based on this assessment using this criteria, our management determined that our internal control over financial reporting was effective as of December 31, 2018.

Attestation Report of the Independent Registered Public Accounting Firm

Pursuant to the provisions of the JOBS Act, this Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm as we are an "emerging growth company."

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2018.

Our board of directors has adopted a Code of Business Conduct and Ethics, which applies to all our officers and employees, a Code of Ethics for Senior Officers of the Company and a Code of Business Conduct and Ethics for Directors, which applies to all our directors. A copy of each of these codes of business conduct and ethics is available on our website at http://icdrilling.investorroom.com. Stockholders may also request a printed copy of either code of business conduct and ethics, free of charge, by contacting us at Independence Contract Drilling, Inc., 20475 State Highway 249, Suite 300, Houston, TX 77070 or by telephone at (281) 598-1230 or by emailing Investor.relations@icdrilling.com. Any waiver of any of the codes of business conduct and ethics for executive officers or directors may be made only by our Board or a Board committee to which the Board has delegated that authority and will be promptly disclosed to our stockholders as required by applicable United States federal securities laws and the corporate governance rules of the NYSE. Amendments to either code of business conduct and ethics must be approved by our Board and will be promptly disclosed (other than technical, administrative or non-substantive changes) on our website.

ITEM 11. *EXECUTIVE COMPENSATION*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2018.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2018.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2018.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Shareholders, which will be filed with the SEC within 120 business days of December 31, 2018.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a) List of filed documents:

(1) Financial Statements

Our Consolidated Financial Statements and accompanying footnotes are included under Part II, "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

(2) Financial Statement Schedules

Schedule II - Valuation and Qualifying Accounts is included under Part II, "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

(3) Exhibits

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

(b) Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K and are incorporated herein by reference.

ITEM 16. *FORM 10-K SUMMARY*

None.

SIGNATURES

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

		INDEPENDENCE CONTRACT DRILLING, INC.
Date: March 1, 2019	By:	/s/ J. Anthony Gallegos Jr.
		Name: J. Anthony Gallegos Jr.
		Title: President, Chief Executive Officer and Director (Principal Executive Officer)

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints J. Anthony Gallegos Jr. and Philip A. Choyce, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:		
March 1, 2019	By:	/s/ J. Anthony Gallegos Jr.
		Name: J. Anthony Gallegos Jr.
		Title: President, Chief Executive Officer and Director (Principal Executive Officer)
March 1, 2019	By:	/s/ Philip A. Choyce
		Name: Philip A. Choyce
		Title: Executive Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)
March 1, 2019	By:	/s/ Michael J. Harwell
		Name: Michael J. Harwell
		Title: Vice President - Finance and Chief Accounting Officer (Principal Accounting Officer)
March 1, 2019	By:	/s/ Thomas R. Bates, Jr.
		Name: Thomas R. Bates, Jr.
		Title: Director
March 1, 2019	By:	/s/ James D. Crandell
		Name: James D. Crandell
		Title: Director
March 1, 2019	By:	/s/ Matthew D. Fitzgerald
		Name: Matthew D. Fitzgerald
		Title: Director
March 1, 2019	By:	/s/ Daniel F. McNease
		Name: Daniel F. McNease
		Title: Director
March 1, 2019	By:	/s/ James G. Minmier
		Name: James G. Minmier
		Title: Director
March 1, 2019	By:	/s/ Adam Piekarski
		Name: Adam Piekarski
		Title: Director

Glossary of Oil and Natural Gas Terms

Glossary of Oil and Natural Gas Terms

AC programmable rig	An AC electric rig with programmable controls.
Basin	A large depression on the Earth’s surface in which sediments accumulate and may be a source of oil and natural gas.
Blowout	An uncontrolled flow of reservoir fluids into the wellbore, and in extreme cases to the surface.
BOP	Blowout preventer; a large valve at the top of a well that may be closed to prevent a loss of pressure.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, abandonment.
Cratering	Caving in of a well that has already been drilled.
Dayrate	The daily fee paid to the drilling contractor, which includes the cost of renting the drilling rig.
Daywork contract	A contract under which the drilling contractor is paid a certain price or rate for work performed as requested by the operator over a 24-hour period, with the price determined by the location, depth and complexity of the well to be drilled, operating conditions, the duration of the contract and the competitive forces of the market.
E&P	Exploration and production.
GHG	Greenhouse gases.
Horizontal drilling	A subset of the more general term “directional drilling,” used where the departure of the wellbore from vertical exceeds about 80 degrees.
HP	Horsepower.
Hydraulic fracturing	A stimulation treatment routinely performed on oil and natural gas wells in low permeability reservoirs.
Pad	Location where well operators perform drilling operations on multiple wells from a single drilling site.
Reservoir	A subsurface body of rock having sufficient permeability to store and transmit fluids.
Rig down	To take apart equipment for storage and portability of the rig.
Rig up	To prepare and assemble the drilling rig for drilling; and to install tools and machinery before drilling is started.
Top drive	A device that turns the drillstring while suspended from the derrick above the rig floor.
Unconventional resource	A term for oil and natural gas that is produced from lower permeability reservoirs by unconventional means, such as horizontal drilling and multistage fracturing.
Utilization	Rig utilization percentage is calculated as rig operating days divided by the total number of days our drilling rigs are available in the applicable period.

Walking rig A land drilling rig that is capable of lifting legs through hydraulic lifts and moving to a nearby location without having to rig down and disassembling the rig. A "multi-directional" or "omni-directional" walking rig has the ability to walk on either the X or Y axis. A "walking" rig is technologically superior to a "skidding" rig, which requires disconnecting the rig and engaging hydraulic cylinders to push the rig across steel skid beams.

Wellbore The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.