Independence Contract Drilling, Inc.
Form 10-K
March 16, 2015

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, 2014
OR

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

For the transition period from to
Commission file number 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.)
11601 North Galayda Street Houston, Texas	77086
(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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer		Accelerated Filer
Non-Accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company

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

As of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, the registrant's equity was not listed on a domestic exchange or over-the-counter market, and, therefore, the aggregate market value of the registrant's common stock held by non-affiliates on such date cannot be reasonably determined. The registrant's common stock began trading on the New York Stock Exchange on August 8, 2014.

There were 24,629,333 shares of the registrant’s common stock outstanding as of March 13, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant’s 2015 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.

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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" with 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 fut 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:

- our inability to implement our business and growth strategy;
- a sustained decrease in domestic spending by the oil and natural gas exploration and production industry;
- decline in or substantial volatility of crude oil and natural gas commodity prices;
- fluctuation of our operating results and volatility of our industry;
- inability to maintain or increase pricing on our contract drilling services;
- delays in construction or deliveries of our new land drilling rigs;
- the loss of our customer, financial distress or management changes of potential customers or failure to obtain contract renewals and additional customer contracts for our drilling services;
- an increase in interest rates and deterioration in the credit markets;
- our inability to raise sufficient funds through debt financing and equity issuances needed to fund our planned rig construction projects;
- 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;
- overcapacity and competition in our industry;
- 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;
- the potential failure by us to establish and maintain effective internal control over financial reporting;
- differences in our future results of operations compared to GES, which is currently deemed to be our accounting predecessor; and
- lack of operating history as a contract drilling company.

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. and the terms "GES," "predecessor" and "our predecessor" refer to Global Energy Services Operating, LLC.

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 entirely of newly constructed, technologically advanced, custom designed ShaleDriller™ rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and gas properties. All of our operating rigs are currently drilling in the Permian Basin, but our rigs have previously operated in the Mid-Continent region and Eagle Ford Shale. We are focused on creating stockholder and customer value through our commitment to operational excellence and our focus on safety. Although we believe the current downturn in oil prices will present significant challenges for the drilling industry, we believe that we are well positioned to successfully navigate the downturn due to our premium rigs, operational excellence, commitment to safety, term contract coverage and strong balance sheet.

Our standardized fleet currently consists of fourteen premium ShaleDriller™ rigs, including three rigs under construction. Of these fourteen rigs, twelve include our integrated multi-directional walking system that is specifically designed to optimize pad drilling for our customers. We also have the option to upgrade our two non-walking rigs when they are not under contract. Every ShaleDriller™ rig in our fleet is a 1500-hp, AC programmable rig ("AC rig") designed to be fast-moving between drilling sites and is equipped with top drives, automated tubular handling systems and blowout preventer ("BOP") handling systems. Twelve of our fourteen rigs are equipped with bi-fuel capabilities (they operate on either diesel or a natural gas-diesel blend).

Our first rig began drilling in May 2012. All of our operating rigs have been contracted prior to the completion of construction, and every rig has been constructed and commenced drilling operations in accordance with our customers' delivery requirements. Although our ShaleDriller™ rig is capable of drilling in virtually any onshore area in the U.S., we currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas facilities in order to maximize economies of scale.

Industry Trends

Land Rig Replacement Cycle

The increase in horizontal drilling in the U.S. over the past ten years has resulted in an ongoing land-rig replacement cycle in which the contract drilling industry is systematically upgrading its legacy fleets of SCR and mechanical rigs with modern AC rigs that are specifically designed to optimize this type of drilling activity. 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 U.S. 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 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 Developmental Drilling

Following their significant investments made in unconventional resource plays, many E&P companies are now focused on developing these investments in a systematic manner. Efficient development of these resource plays involves drilling programs that drill large numbers of wells 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. 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. As a result, we believe that E&P companies drilling horizontal wells are going to increasingly demand not only AC rigs that are optimal for horizontal drilling, but premium AC rigs such as our ShaleDriller™ rig that include the following 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 silicon-controlled rectifier (“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, Multi-Directional Walking System. Our multi-directional walking system is engineered and designed as an integrated part of our ShaleDriller™ rig’s substructure 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 system allows our rigs to 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.

- Bi-Fuel Capable. Twelve of our fourteen ShaleDriller™ rigs are bi-fuel capable. Bi-fuel operations offer a reduction in carbon emissions and provide significant fuel cost savings for our customers.

- 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. In addition to being specifically designed for moving between wells on a pad, our ShaleDriller™ rig is designed to move rapidly on conventional rig moves between drilling sites. Our custom designed substructure moves in a single semi-trailer load and allows for automated and rapid rig up and rig down without the use of cranes. This significantly reduces overall move time compared to a traditional substructure design, provides cost savings to our customers, and enables a safer rig up and rig down process.

- 1500-hp Drawworks. All of our rigs are powered with 1500-hp drawworks and 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 strength lengths required to drill long horizontal wells, which are becoming more common in the markets we serve.

- BOP Handling Systems. Our BOP handling system allows precise control and positioning of the BOP stack via remote control and removes the handling of the BOP stack from the critical path of well operations. BOP handling systems enable the drilling rig to walk from well to well by suspending the BOP stack from the substructure. BOP handling systems provide a safer and more efficient BOP handling operation when compared to conventional methods, which require lifting of the BOP by third-party rental equipment or through use of the rig’s traveling block.

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Increased Use of Pad Drilling

Pad drilling involves the drilling of multiple wells from a single location, which provide 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 drilled 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 a batch, then drills all of the intermediate sections, and concludes with the drilling all of the laterals. Efficiencies are created because hole sizes change less often 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 address the complexities associated with the growing number of wells per pad. In addition to quickly moving from well to well, multi-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.

Shift to Longer Lateral Lengths

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. Our rigs have drilled some of the longest horizontal wells to date in the Permian Basin, including a well with a lateral section in excess of 13,980 feet. 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 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.

Recent Declines in Oil and Gas Prices and Drilling Activity

Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $49.84 per barrel during the last week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn and market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2015 will be a very challenging year for our industry.

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

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells. As a result, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling. They also are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller™, and that premium operations such as ours will be less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller™ rig. During

2014, we have operated our premium drilling fleet with 99.7% contractual utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. Since December 31, 2014, one of our non-walking rigs has become idle and we are evaluating whether to continue marketing this rig or to upgrade it with our multi-directional walking system. We also have four other drilling rigs operating under contracts with terms expiring during the first half of 2015. We expect to market these rigs at substantially lower dayrates than their expiring contracts and at lower contractual utilization rates than where we historically have operated, and there can be no assurance that these rigs will remain operating at profitable levels.

Initial Formation

We were incorporated in November 2011 but did not have meaningful operations until March 2012. In March 2012, we acquired substantially all of the rig manufacturing and related field service assets and intellectual property (the “GES assets”) of Global Energy Services Operating, LLC (“GES”), including GES’ Houston-based manufacturing facility (the “Houston Facility”), which we currently use to construct our rig fleet. The Houston Facility is located on 14.6 acres in northwest Houston. We believe this acquisition provided us with the necessary infrastructure and asset platform required to accelerate the introduction of our ShaleDriller™ rig into our target markets and secure initial contracts with key customers. In exchange for the GES assets, we issued 1.6 million shares of our common stock and a warrant to purchase 2.2 million shares of our common stock, which expired unexercised on March 2, 2015, and we assumed approximately $2.1 million of long-term indebtedness from GES. Because we had only limited operations before the GES acquisition and we succeeded to substantially all of the ongoing rig construction operations of GES, GES is considered our predecessor for accounting purposes.

Contemporaneously with the acquisition of the GES assets, we acquired cash balances and two drilling contracts from Independence Contract Drilling LLC (referred to as “RigAssetCo”) in exchange for approximately 2.4 million shares of our common stock. As a condition to the completion of these two transactions, we also closed a private placement of shares of our common stock resulting in net proceeds to us of $98.4 million. We used the net proceeds of the private placement primarily to continue the construction of our ShaleDriller™ rig fleet and expansion of our operating capacity, and to repay the indebtedness assumed from GES. We refer to the GES and RigAssetCo transactions, together with the private placement of common stock, collectively as the “GES Transaction.”

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 fixed 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 for 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 numbers of hours in a given day or calendar month.

Our contract drilling backlog, or the expected future revenue from executed contracts with original terms in excess of six months, as of December 31, 2014 was $152.8 million compared to $25.8 million as of December 31, 2013. The increase in backlog at December 31, 2014 from December 31, 2013 is primarily due to additional term contracts being executed as we implemented our growth strategy and gained customer acceptance of our safe and efficient operations. Approximately 55%, or $84.2 million, of the total December 31, 2014 backlog is expected to be filled in the year ended December 31, 2015, and 45% or $68.6 million thereafter. Approximately 42% of the December 31, 2014 backlog represents term contracts for new rigs that were not yet complete as of December 31, 2014.

Our Customers

Customers for contract drilling services in the U.S. include major oil and gas companies, independent oil and gas companies as well as numerous small to mid-sized publicly-traded and privately held oil and gas companies. We market our contract drilling services to all such customers. During 2014, our customers representing more than 10% of our revenues were Apache Corporation, BOPCO, L.P., COG Operating, LLC, a subsidiary of Concho Resources, Inc. and Laredo Petroleum, Inc. While we would attempt to remarket our rigs if we lost any material customer, given current market conditions, the terms of such new contract, if any were found, may be less favorable than the terms of our current contracts. Therefore, the loss of any material customer could have an adverse effect on our business.

Industry/Competition

To a large degree, our business depends on the level of capital spending by oil and 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. For example, the recent decrease in oil prices has caused a reduction in E&P company capital expenditures on exploration, development and production activities, which in turn has resulted in a decreased demand for drilling rigs and downward pricing pressure on drilling rigs in operation.

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 U.S. 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, quality of personnel, efficiency of equipment, service quality, experience and safety record.

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

Our Business Strategy

Our principal business objectives are to profitably and responsibly grow our business and increase stockholder value. We expect to achieve these objectives through the following strategies:

Continuing to Focus on Safety and Operational Efficiency. Our incentive compensation programs are designed to directly align all levels of our operations with our strategic goal of providing the highest level of service through a focus on safety and operational efficiency while maintaining a cost effective operating structure. We believe we are one of only a few land drilling contractors who have implemented a safety management system compliant with the U.S. Bureau of Safety and Environmental Enforcement’s SEMS II workplace safety rules. These workplace rules are independently developed standards applicable to offshore oil and gas operations in U.S. federal waters, which we believe also provide enhanced safety practices for our onshore activities. In addition, we have implemented proven training programs to enhance competency and prepare for future workforce needs. We intend to maintain and enhance our organizational culture to promote a safer work environment, and to maximize operational performance and value for our customers.

Capitalizing on Developmental Drilling in Unconventional Resource Plays. We intend to continue to focus our services in demanding unconventional resource plays with what we view as long-term development potential, where we believe our ShaleDriller™ rig and operating strategy will provide superior returns. Despite the recent downturn in oil prices, due to advances in drilling and completion technologies as well as shale/basin specific production costs, we believe E&P companies will continue to invest capital into the unconventional resource plays that we target. Our premium rigs’ features are specifically designed to efficiently and economically address the technical challenges posed by these and other resource plays where horizontal drilling is utilized.

Expansion of our Rig Fleet. As of December 31, 2014, we had three rigs under construction that are backed by multi-year term contracts, which we intend to complete in 2015. Unless market conditions begin to improve, we do not intend to construct any additional new Shaledriller™ rigs during 2015. However, we have the option to do so and also have the option to equip our two non-walking rigs with our Sharedriller multi-directional walking system later in the year.

Expanding Customer Relationships. We target customers who have significant investments in our target markets, who value safe and efficient operations and who have the financial stability to drill through industry cycles and enter into long-term relationships with us. We believe there is significant opportunity to expand our customer relationships by providing our customers with superior service and advanced rig capabilities. We seek to deliver the best value to our customers through our dual focus on safety and operating efficiencies.

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 U.S. 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 U.S., the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended ("CERCLA"), and comparable state statutes impose strict liability on:

- owners and operators of sites, and
- persons who disposed of or arranged for the disposal of "hazardous substances" found at sites.

The Federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes govern the disposal of "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, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

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

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

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. Penalties may also be imposed for violation of Federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

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

Our contract drilling services will be marketed in oil and 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 groundwater quality, 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 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 Enforcement 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 state and local regulations, such as the EPA rules issued in April 2012, which add new requirements for the oil and 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 greenhouse gases 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 gas production. Pursuant to President Obama’s Strategy to Reduce Methane Omissions, and as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025, the Obama Administration announced on January 14, 2015 that the EPA is expected to propose in the summer of 2015, and to finalize in 2016, new regulations that will set methane emission standards for new and modified oil and 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 Endangered Species Act (“ESA”), 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 U.S., 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 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, 2014, we had approximately 323 employees, including 2 contract employees, none of who 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.

Raw Materials, Suppliers and Subcontractors

We use many suppliers of raw materials and services. Although these materials and services have historically been available, there is no assurance that such materials and services will continue to be available on favorable terms or at all. We also utilize numerous 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. Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also 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

Recent declines in oil prices have adversely affected demand for contract drilling services, which could have a material adverse affect on our results of operations and financial condition.

Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $49.84 per barrel during the last week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn. Market conditions remain very dynamic and are changing quickly and we believe that 2015 will be a very challenging year for our industry.

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

As a result of this deterioration in market conditions, demand for our contract drilling services has declined. One of our non-walking rigs currently is not operating under a contract and four of our rigs that are operating under contracts have terms expiring during the first half of 2015. If we are unable to re-contract these rigs during 2015, it could have a material adverse affect on our results of operations and financial condition. In addition, we expect that any rig that is recontracted during 2015 will be at dayrates substantially below their current contract rates, which will significantly reduce our profitability and cash flows.

In addition, we currently finance our capital expenditures and operations pursuant to a committed $155.0 million revolving line of credit. A significant portion of our borrowing base is tied to the appraised value of our drilling rigs, which may decline if market conditions deteriorate further. A significant decline in our borrowing base could have a material adverse effect on our financial condition. Our revolving credit facility also contains certain restrictive covenants, including a leverage covenant based upon the cash flows of the company. Thus, a significant reduction in our cash flows as a result of the decline in demand for our products and services could reduce or limit the level of funds we are able to borrow under our existing revolving credit facility, and thus have a material adverse affect on our financial condition.

We derive all our revenues from companies in the oil and 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 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 gas companies operating in the U.S., and in particular, the regions where we actively market our contract drilling services. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and 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 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 U.S. and the regions where we market our contract drilling services, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect us in many ways by negatively impacting:

- our revenues, cash flows and profitability;
- 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 rig construction and growth 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 gas, oil and 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 gas prices, including, but not limited to:

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

Oil and natural gas prices have been volatile historically and, we believe, will continue to be so in the future. For example, U.S. Benchmark crude’s price per barrel (West Texas Intermediate - Cushing, Oklahoma) was $107.95 on June 20, 2014 and had dropped to $44.08 by January 28, 2015, an approximately 59% decrease over a less than eight month period. Future or continued declines and volatility in oil and gas prices, or no improvement in oil and gas prices, from their current levels for an extended period of time, could materially and adversely affect our business, results of operations, financial condition and growth strategy.

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. 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, 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, it could have a material adverse effect on our business and financial results and our ability to timely and successfully implement our growth strategy.

A significant delay in the completion of the construction of our planned additional rigs in 2015 could materially and adversely affect our ability to execute our growth strategy.

We currently have three rigs under construction. Each of the three rigs to be constructed during 2015 is subject to a multi-year drilling contract with a specified delivery date range. If we are unable to deliver a rig in accordance with its delivery deadline, the customer may, subject to a grace period in certain scenarios, terminate the contract, which could have a material adverse effect on our future cash flows and financial condition.

Our growth strategy may require us to commit to the construction of new drilling rigs prior to securing an executed contract for its use. The inability to secure drilling contracts for our new rigs promptly following the completion of their construction could materially and adversely affect our financial condition.

Because much of the equipment and parts required for the construction of our rigs must be ordered in advance, our growth strategy will likely require that we make significant purchases of equipment, and commit to constructing our rigs, prior to having executed customer contracts for their use. If we are unable to timely secure drilling contracts for all of our newly constructed rigs, it could materially and adversely affect our financial condition. We currently have made progress payments of $8.0 million for long-lead time items for new drilling equipment for which purchase has been deferred beyond 2015. If we elect to cancel these orders, the progress payments we have made could be forfeited and we may be subject to additional claims by our vendors.

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 gas wells in the United States in the regions where we market our rigs. We currently have thirteen executed drilling contracts (including for three rigs under construction) with eight different customers. Furthermore, 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 major 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 major customer, revenue would decline and our business, results of operations, financial condition and growth strategy could be adversely affected.

One of our drilling rigs became idle in January 2015 and four of our existing drilling contracts are scheduled to terminate during the first half of 2015. If we are unable to renew our expiring contracts at favorable pricing, or alternatively secure new contracts at favorable pricing, it could have a material and adverse effect on our results of operations and financial condition.

All of our current drilling contracts have original or current extended terms of between 12 and 36 months. In any event, our contracts provide that our customers may terminate at any time upon payment to us of an "early termination payment." One of our drilling rigs became idle in January 2015 and four of our existing drilling contracts are scheduled to terminate during 2015. Our customers have no obligation to extend the term of any drilling contract and may elect to release the rig. We have not yet recontracted the rig that went off contract in January 2015 and we cannot assure you that any particular contract will be renewed, or if terminated, that a replacement contract could be immediately secured. In addition, in light of the current downturn in oil prices, we cannot assure you that any replacement contract can be obtained, and if obtained, that it would be on terms as favorable as those of our existing drilling contracts. The failure to renew or timely replace one or more of our expiring contracts could have a material and 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 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. For example, during March 2014, we experienced damage to the mast of one of our operating rigs that removed the rig from operations for a period of time, during which we were not compensated. 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 recent 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, financial condition and ability to implement our growth strategy. 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. Several of our competitors provide a broader array of services and have a stronger presence in more geographic markets.

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 Environmental Protection Agency (the "EPA") has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and published guidance relating to such practices in February 2014. 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. The EPA commenced a study of the potential impacts of hydraulic fracturing on drinking water and issued an update on December 21, 2012, with a draft report expected for public comment and peer review in 2015. On October 21, 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing. On May 24, 2013, the U.S. Department of the Interior (the "DOI") published a revised proposed rule that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity and handling of flowback water. On April 13, 2012, the DOI, the U.S. Department of Energy and the EPA issued a memorandum outlining a multi-agency collaboration on unconventional oil and gas research in response to the White House-entitled "Blueprint for a Secure Energy Future" and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. 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 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 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.

Reduced demand for or excess capacity of drilling services could adversely affect our profitability.

Our profitability in the future will depend on many factors, especially pricing and utilization rates of our drilling services. A reduction in the demand for drilling rigs or an increase in the supply of drilling rigs, whether through new construction or refurbishment, could decrease the dayrates and utilization rates for our drilling services, which would adversely affect our revenues and profitability.

Prior to the recent decline in oil prices, we and our competitors ordered additional drilling rigs to meet then existing and projected long-term demand, resulting in significant increases in drilling industry capacity. We currently have three rigs under construction and we believe our competitors also have additional rigs under construction. As the recent decline in oil prices demonstrates, our industry is characterized by a high degree of volatility. In the event that our customers reduce their level of investment in exploration, production and development activities, which we believe is currently occurring, the increased supply of drilling rigs could exceed the reduced level of demand for drilling services. Any excess supply could cause our competitors to lower their rates in order to maximize utilization of their fleets, and could lead to a decrease in rates in the drilling industry generally, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We also have outstanding aggregate progress payments of $8.0 million for equipment for new drilling rigs where purchase has been deferred past 2015, which could be subject to forfeiture if depressed market conditions continue and we elected to cancel these orders.

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, in particular Mr. Dunn and Mr. Jacob, our Chief Executive Officer and our President and Chief Operating Officer, respectively, 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, refurbishment and new rig construction projects are subject to risks which could cause delays or cost overruns and adversely affect our cash flows, results of operations, and financial position.

New drilling rigs may experience start-up complications during construction or following delivery, 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 construction 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.

As we construct additional rigs in the future, we may experience difficulty integrating those rigs into our operations. Additionally, we may incur leverage and add additional financial risk to our business. To the extent we incur additional leverage in our business, it may adversely affect our results of operations, financial position and growth strategy.

The process of constructing rigs may involve unforeseen difficulties and may require a disproportionate amount of management's attention and other resources. We may not be able to successfully manage and integrate new rigs into our existing operations or successfully market our rigs and build market share attributable to drilling rigs that we construct. To the extent we experience some or all of these difficulties, our results of operations, financial condition and growth strategy could be adversely affected.

Expanding our fleet may cause us to incur additional financial leverage, increasing our financial risk and debt service requirements, which could adversely affect our business, results of operations, financial condition and growth strategy.

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

As of December 31, 2014, 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 $152.8 million. 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 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. 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 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 under our revolving credit facility 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 revolving credit facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition. 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 revolving credit facility contains 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 our revolving credit facility 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, our revolving credit facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements. 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.

Any significant reduction in our borrowing base under our revolving credit facility would negatively impact our ability to fund our operations and business strategy.

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which is calculated monthly and is based upon the appraised value of our eligible drilling fleet and a percentage of our eligible accounts receivable. If a rig becomes idle for longer than 90 consecutive days, it is removed from our borrowing base until it resumes operations. The borrowing base under our revolving credit facility was $114.8 million as calculated as of December 31, 2014, with lender commitments of $155.0 million.

In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender’s portion. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

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.

The delivery of our services and products and construction of our rigs requires personnel with specialized skills and experience who can perform physically demanding work. As a result of the volatility of the contract drilling industry and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment at wage rates that are competitive.

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 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 ability to be productive and profitable will depend upon our ability to employ and retain skilled personnel and we cannot assure you 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. 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 and our ability to construct new drilling rigs in a timely manner depend on 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 construction of our rigs are either purchased from or fabricated by a single or limited number of vendors. 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 for consumable supplies, including fuel, and ancillary rig equipment, such as pumps, valves, drillpipe and engines, may lead to delays in obtaining these materials and our inability to operate our rigs in an efficient manner. Most of our contracts provide that our customers purchase the fuel that run our drilling rigs and thus bear the financial impact of increased fuel prices. However, prolonged shortages in the availability of fuel to run our drilling rigs resulting from action of the elements, terrorism or other force majeure events could result in the suspension of our contracts and have a material adverse effect on our financial condition and results of operations. 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.

Reduced demand can drive suppliers from the market. With reduced suppliers, consumables for our operations may not be readily available. Additionally, suppliers may experience shortfalls in obtaining their materials and/or labor. Suppliers who have been regular providers to us may experience shortfalls that may lead to delays as we secure other sources.

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 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 and could limit well servicing opportunities. 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 Endangered Species Act 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 Endangered Species Act (the “ESA”) and analogous state laws regulate a variety of activities, including oil and 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 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, in March 2014 the U.S. Fish & Wildlife Service (the "FWS") listed the lesser prairie-chicken as threatened and finalized a special rule that would exempt from regulation under the ESA activities harmful to the prairie-chicken if incidental to carrying out the state-developed range-wide lesser prairie-chicken conservation plan. Some environmental groups have filed a notice of intent to sue FWS to require more state protection. The sage grouse and certain wildflower species, among others, are also 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 provided 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 gas industry. During 2012, the EPA published rules that include standards to reduce methane emissions associated with oil and gas production. Pursuant to President Obama's Strategy to Reduce Methane Omissions, and as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025, the Obama Administration announced on January 14, 2015 that the EPA is expected to propose in the summer of 2015, and to finalize in 2016, new regulations that will set methane emission standards for new and modified oil and gas facilities, including production facilities. In addition, the U.S. has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change. 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 and 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 Common Stock

Our stock price is subject to volatility.

The market price of common stock of companies engaged in the oil and 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 the recent 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 revolving 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.

In the future, we may attempt to increase our capital resources by making offerings of debt or additional offerings of 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.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

In April 2012, President Obama signed into law the JOBS Act. We are classified as an “emerging growth company” under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things: (i) provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002; (ii) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; (iii) provide certain disclosure regarding executive compensation required of larger public companies; or (iv) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our common stock held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

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.

Existing stockholders will continue to hold a significant percentage of our outstanding common stock.

As of March 13, 2015, Sprott Resource Partnership, Lime Rock Partners III, L.P., 4D Global Energy Advisors SAS, Global Energy Services Operating, LLC, Jennison Associates LLC, Prudential Financial, Inc. and FMR LLC each hold or beneficially own more than 10% of our common stock. The existence of significant stockholders may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with significant stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own an approximately 14.4 acre corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, TX 77086. The complex includes approximately 18,000 square feet of office space and 76,000 square feet of warehouse space. We have entered into leases for additional land for equipment and supply storage. We believe that all of our existing properties are suitable for their intended uses and 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 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 are asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that 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 has traded on the New York Stock Exchange under the symbol “ICD” since August 8, 2014 following our initial public offering. Prior to that time, there was no public market for our common stock. The table below presents the high and low daily closing sales prices of the common stock, as reported by the New York Stock Exchange, for each of the applicable quarters presented during the year ended December 31, 2014:

	High	Low
2014:		
Period from August 8, 2014 to September 30, 2014	$11.94	$10.87
Fourth Quarter	$11.69	$5.06

Holders of Record

As of March 13, 2015, we had 24,629,333 shares of common stock outstanding held by approximately 20 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 revolving 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 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, 2014 with total stockholder return during the same period for the Standard & Poors 500 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.

	August 8, 2014	August 29, 2014	September 30, 2014	October 31, 2014	November 28, 2014	December 31, 2014
Independence Contract Drilling, Inc.	$100.00	$103.98	$106.24	$66.27	$62.39	$47.20
S&P 500 Index	$100.00	$103.72	$102.11	$104.48	$107.04	$106.59
Peer Index	$100.00	$101.40	$93.94	$72.71	$55.65	$53.04

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

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

None.

Issuer Purchases of Equity Securities

Neither we nor any affiliated purchaser purchased any of our equity securities during the fourth quarter of fiscal 2014.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical financial data and that of our accounting predecessor as of and for the periods indicated. Our accounting predecessor was GES Drilling Services, a division of Global Energy Services, Inc. For more information regarding our predecessor, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Period from January 1, 2012 Through March 1, 2012 for Our Predecessor.”

Our selected historical financial data as of and for the periods presented below were derived from our audited financial statements. Our results of operations during 2012 do not include the results of our predecessor prior to its acquisition. Although we did not commence material operations prior to March 2, 2012, we incurred expenses in connection with our private placement and acquisition activities during January and February 2012 prior to the consummation of these transactions.

The selected historical financial data of our predecessor for the period from January 1, 2012 through March 1, 2012 were derived from the audited financial statements of our predecessor. Our predecessor was engaged in a different line of business and you should not evaluate our results based on our predecessor or consider our results and those of our predecessor on a combined basis.

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 financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data."

	Successor			Predecessor
	Year Ended			
(In thousands, except per share data)	December 31, 2014	December 31, 2013	December 31, 2012	January 1, 2012 through March 1, 2012
Statement of operations data[1]:				
Revenues	$70,347	$42,786	$15,123	$7,698
Operating costs	42,654	28,401	15,400	6,973
Selling, general and administrative	12,222	8,911	7,813	1,383
Depreciation and amortization	16,181	10,186	5,904	92
Goodwill impairment and other charges[2]	30,627	—	—	—
Asset impairment, net of insurance recoveries[3]	1,711	—	—	—
(Gain) loss on disposition of assets	19	(55)	—	—
Total cost and expenses	103,414	47,443	29,117	8,448
Operating loss	(33,067)	(4,657)	(13,994)	(750)
Interest expense	(1,648)	(257)	(10)	(15)
Loss on forgiveness of related party balances[4]	—	—	—	(6,063)
Gain on warrant derivative[5]	3,189	1,035	3,655	—
Loss before income taxes	(31,526)	(3,879)	(10,349)	(6,828)
Income tax benefit	(3,358)	(1,882)	(5,401)	(2,149)
Net loss	$(28,168)	$(1,997)	$(4,948)	$(4,679)
Weighted-average number of shares outstanding (basic and diluted)	17,078	12,179	10,141	
Net loss per share (basic and diluted)	$(1.65)	$(0.16)	$(0.49)	
Cash flow data:				
Net cash provided by (used in) operating activities	$3,809	$5,997	$(8,337)	$(3,857)
Net cash used in investing activities	(112,686)	(59,273)	(49,743)	(18)
Net cash provided by (used in) financing activities	116,904	18,599	95,486	(25)
Balance sheet data:				
Total assets	$289,547	$184,968	$167,436	
Long-term debt	22,519	19,780	—	
Total liabilities	52,811	40,096	22,736	
Total stockholders' equity	236,736	144,872	144,700	

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

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

(3) Represents asset impairment expense associated with damage sustained to the mast and other operating equipment on one of our non-walking rigs during the three months ended March 31, 2014, net of insurance claim proceeds. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(4) Represents amounts owed to our predecessor by its affiliate that were forgiven in the GES Transaction.

(5) Represents a non-cash gain associated with the decrease in the estimated fair value of the warrant to purchase 2.2 million shares issued to GES in the GES Transaction. 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 Historical Financial Data" and the 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 10K.

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 construct, own and operate a premium fleet comprised entirely of newly constructed, technologically advanced, custom designed ShaleDriller™ rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and gas properties. Our first rig began drilling in May 2012.

Our standardized fleet consisted of fourteen premium rigs as of December 31, 2014. Of these fourteen rigs, three are currently under construction and scheduled for completion during 2015. Currently, twelve of our fourteen rigs contain our integrated multi-directional walking system that is specifically designed to optimize pad drilling for our customers.

Our business depends on the level of exploration and production activity by oil and gas companies operating in the U.S., and in particular, the regions where we actively market our contract drilling services. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and 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 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 U.S. and the regions where we market our contract drilling services, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect our business.

In this regard, oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $49.84 per barrel during the last week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn. Market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2015 will be a very challenging year for our industry.

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

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells. As a result, operators are focusing more of their capital spending on horizontal drilling programs on multi-well pads compared to vertical drilling and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller™, and that premium operations such as ours will be less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller™ rigs. During 2014, we have operated our premium drilling fleet with 99.7% contractual utilization, but we do not expect to maintain this level of utilization while this market downturn continues. Since December 31, 2014, one of our non-walking rigs has become idle and we are evaluating whether to continue marketing this rig or to upgrade it with our multi-directional walking system. We also have four other drilling rigs operating under contracts with terms expiring during the first half of 2015. We expect to market these rigs at substantially lower dayrates than their expiring contracts and at lower contractual utilization rates than where we historically have operated, and there can be no assurance that these rigs will remain operating at profitable levels.

Recent Developments

Damage Sustained on Rig 102

On March 9, 2014, one of our non-walking drilling rigs suspended drilling operations due to damage to the rig’s mast and other operating equipment. We believe the cost to repair and replace this equipment is covered by insurance, subject to
a $250,000 deductible. While under repair, we upgraded this rig by adding a substructure and other equipment that includes a multi-directional walking system. The cost of the upgrades were not covered by insurance. The repairs and upgrades were completed in October 2014 when the upgraded rig recommenced operations. We recorded an asset impairment charge of $4.7 million during the three months ended March 31, 2014, representing a preliminary estimate of the damage sustained to the rig. During the three months ended June 30, 2014, we recorded approximately $2.3 million in insurance recoveries related to repairing damage to the rig ($2.0 million) as well as the recovery of certain out-of-pocket expenses ($0.3 million), for which we had received a partial proof of loss from the insurance company. As of September 30, 2014, all of the $2.3 million had been collected. In the fourth quarter of 2014, we recorded an additional $1.6 million in insurance recoveries related to repairing damage to the rig ($1.0 million) as well as the recovery of certain out-of-pocket expenses ($0.6 million), for which we had received a second partial proof of loss from the insurance company. We expect to record additional insurance recoveries estimated at approximately $1.3 million in the first quarter of 2015 when the final proof of loss is obtained.

Stock Split

On July 14, 2014, our board of directors approved a resolution to effect a 1.57-for-1 stock split of our common stock in the form of a stock dividend. The dividend was distributed on July 24, 2014 to holders of record as of July 21, 2014. The earnings per share information and all common stock information in these financial statements have been retroactively restated for all periods presented to reflect this stock split.

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) (the "Form S-1") was declared effective by the Securities and Exchange Commission for our IPO pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 shares of our common stock sold pursuant to the exercise by the underwriters in full of their option to purchase additional shares of common stock to cover over-allotments (the "Over-Allotment Option"). We completed our initial public offering of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol "ICD." Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million. All of the outstanding borrowings on our revolving credit facility were repaid immediately following the offering.

Amendment of Revolving Credit Facility

On November 5, 2014 we amended and restated our revolving credit facility with a syndicate of financial institutions led by CIT Finance, LLC. The new revolving credit facility increased the aggregate commitments under our revolving credit facility from $125.0 million to $155.0 million. In addition, the new revolving credit facility provides for an additional uncommitted $25.0 million accordion feature that allows for future increases in the facility. For additional information regarding our revolving credit facility, please see “-Long-Term Debt.”

Our Revenues

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a “daywork” contract basis, under which we charge a fixed 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. 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.

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.

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 believe we are one of the few land drillers that utilizes a safety management system that complies with the Bureau of Safety and Environmental Enforcement's SEMS II workplace safety rules. 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.
- 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, 2014, 2013 and 2012, as well as the financial data for our predecessor for the period from January 1, 2012 through March 1, 2012:

(In thousands, except per share data)	Successor			Predecessor
	Year Ended			
	December 31, 2014	December 31, 2013	December 31, 2012	January 1, 2012 through March 1, 2012
Revenues	$70,347	$42,786	$15,123	$7,698
Costs and expenses				
Operating costs	42,654	28,401	15,400	6,973
Selling, general and administrative	12,222	8,911	7,813	1,383
Depreciation and amortization	16,181	10,186	5,904	92
Goodwill impairment and other charges	30,627	—	—	—
Asset impairment, net of insurance recoveries	1,711	—	—	—
(Gain) loss on disposition of assets	19	(55)	—	—
Total cost and expenses	103,414	47,443	29,117	8,448
Operating loss	(33,067)	(4,657)	(13,994)	(750)
Interest expense	(1,648)	(257)	(10)	(15)
Loss on forgiveness of related party balances	—	—	—	(6,063)
Gain on warrant derivative	3,189	1,035	3,655	—
Loss before income taxes	(31,526)	(3,879)	(10,349)	(6,828)
Income tax benefit	(3,358)	(1,882)	(5,401)	(2,149)
Net loss	$(28,168)	$(1,997)	$(4,948)	$(4,679)
Other financial and operating data				
Number of completed rigs end of period[1]	11	7	4	
Rig operating days[2]	2,944	1,745	472	
Average number of operating rigs[3]	8.07	4.78	1.29	
Rig utilization[4]	99.7%	96.0%	97.0%	
Average revenue per operating day[5]	$22,723	$21,351	$19,528	
Average cost per operating day[6]	$12,759	$12,632	$15,787	
Average rig margin per operating day	$9,964	$8,719	$3,740	

(1) Number of completed rigs as of December 31, 2014 increased by four compared to the number of completed rigs as of December 31, 2013, reflecting the addition of four newly constructed rigs to our fleet. Number of completed rigs as of December 31, 2013 increased by three compared to the number of completed rigs as of December 31, 2012, reflecting the addition of three newly constructed rigs to our fleet.

(2) Rig operating days represent the number of days that our rigs are earning revenue under a contract.

(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 percentage is calculated as rig operating days divided by the total number of days our drilling rigs are available in 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. The following revenues are excluded in calculating average revenue per operating day: (i) revenues associated with reimbursement of costs paid by customers of $3.2 million, $2.4 million and $0.8 million during the year ended 2014, 2013 and 2012, respectively, (ii) direct revenues associated with repair and service and other revenues from third-party drilling contractors of $0.2 million, $3.2 million and $4.0 million during the year

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ended 2014, 2013 and 2012, respectively, and (iii) revenues relating to transition services provided to GES of $1.5 million in 2012.

(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) costs relating to out-of-pocket costs reimbursed by customers of $3.2 million, $2.4 million and $0.8 million during the year ended 2014, 2013 and 2012, respectively, (ii) non-recurring rentals of drilling equipment of $0.5 million and $0.9 million during the year ended 2013 and 2012, respectively, (iii) new crew training costs of $1.8 million and $1.3 million during the year ended 2014 and 2013, respectively, (iv) direct operating costs associated with repair and service and other revenues from third-party drilling contractors of $0.1 million, $2.1 million and $2.9 million during the year ended 2014, 2013 and 2012, respectively, and (v) startup costs of $2.5 million during the year ended 2012 incurred prior to a newly constructed rigs commencing operations.

Revenues

Revenues for the year ended December 31, 2014 were $70.3 million, representing a 64.4% increase over revenues for the year ended December 31, 2013 of $42.8 million. This increase was primarily related to the addition of four drilling rigs into our operating fleet during 2014, which is reflected in the increase in our average number of operating rigs to 8.07 during 2014 compared to 4.78 during 2013 and a full year of operating from the rigs put into service during 2013. Average revenue per operating day increased to $22,723 during 2014, compared to $21,351 during 2013.

Revenues for the year ended December 31, 2013 were $42.8 million, representing a 182.9% increase over revenues for the year ended December 31, 2012 of $15.1 million. This increase was primarily related to the addition of three drilling rigs into our operating fleet during 2013, which is reflected in the increase in our average number of operating rigs to 4.78 during 2013 compared to 1.29 during 2012. Average revenue per operating day increased to $21,351 during 2013, compared to $19,528 during 2012.

Operating Costs

Operating costs for the year ended December 31, 2014 were $42.7 million, representing a 50.2% increase over operating costs for the year ended December 31, 2013 of $28.4 million. This increase was primarily related to the addition of four drilling rigs into our operating fleet during 2014. During the year ended December 31, 2014, our cost per operating day was $12,759, representing a 1% increase compared to 2013 operating cost per day of $12,632.

Operating costs for the year ended December 31, 2013 were $28.4 million, representing an 84.4% increase over operating costs for the year ended December 31, 2012 of $15.4 million. This increase was primarily related to the addition of three drilling rigs into our operating fleet during 2013. During the year ended December 31, 2013, cost per operating day were $12,759, compared to cost per day of $15,787 for the year ended December 31, 2012. The significant decrease was due to greater efficiencies and economies of scale realized by us as we instituted new operating policies and procedures throughout 2012 and 2013.

Selling, General and Administrative Expenses

Selling, general and administrative expenses for the year ended December 31, 2014 were $12.3 million, representing a 38.0% increase over selling, general and administrative expenses for the year ended December 31, 2013 of $8.9 million. This increase primarily relates to costs associated with us becoming a public company in August 2014, including costs associated with increased non-cash stock based compensation relating to awards granted at the IPO, higher executive salaries and other costs associated with maintaining and operating a publicly traded company. In addition, during 2014 we incurred approximately $0.7 million of professional fees and acceleration of vesting of stock-based awards directly associated with the closing of the IPO.

Selling, general and administrative expenses for the year ended December 31, 2013 were $8.9 million, representing a 14.1% increase over selling, general and administrative expenses for the year ended December 31, 2012 of $7.8 million. The increase in 2013 reflects a full year of operations as compared to 2012 in which we did not have meaningful operations until completion of the GES Transaction in March 2012. During 2012, we incurred $0.2 million of expenses associated with the GES Transaction, as well as $0.6 million in severance, legal and other office closure expenses associated with the relocation of our Oklahoma City office to Houston.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2014 was $16.2 million, representing a 58.9% increase compared to the year ended December 31, 2013. This increase was directly related to the introduction of four new

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drilling rigs constructed by us in 2014 and a full year of depreciation for rigs constructed during 2013. We begin depreciating our rigs when they commence drilling operations.

Depreciation and amortization for the year ended December 31, 2013 was $10.2 million, representing a 72.5% increase compared to the year ended December 31, 2012. This increase was directly related to the introduction of three new drilling rigs constructed by us in 2013 and a full year of depreciation for rigs constructed during 2012.

Goodwill Impairment and Other Charges

Goodwill impairment and other charges for the year ended December 31, 2014 was $30.6 million. There was no goodwill impairment and other charges in 2013 or 2012.

The impairments and other charges in December 2014 were deemed necessary due to the significant downturn in industry conditions in late 2014 and related uncertainty regarding demand for our contract drilling services and new rig construction. Based on our analysis of goodwill, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of the goodwill recorded in the Contribution Transaction (defined below). We also accelerated the amortization of our rig manufacturing intellectual property, as we revised the estimate of the remaining useful life from 7.2 years to zero. As a result we recorded additional amortization expense of $19.6 million. This additional amortization expense, as well as our goodwill impairment, were reported in our statement of operations as goodwill impairments and other charges.

Interest Expense

Interest expense for the year ended December 31, 2014 was $1.6 million, as compared to $0.3 million for the year ended December 31, 2013 as a result of increased borrowings under our revolving credit facility. Interest expense for the year ended December 31, 2012 was negligible. We did not borrow under our revolving credit facility until July 2013.

Gain on Warrant Derivative

As part of the consideration paid to GES for their contribution of our rig construction operations and intellectual property, we issued to GES a warrant to purchase 2.2 million shares of common stock. The terms of this warrant contained a feature that would allow the exercise price to be adjusted in the event we issued any shares of common stock at a price below $12.74 per share during the term of the warrant. As a result of this feature, we have accounted for the warrant as a derivative liability on our balance sheet and have recorded changes in fair value each reporting period through earnings. The fair value of the warrant on its date of issuance was estimated at $7.9 million. At December 31, 2012, the fair value of the warrant was estimated at $4.2 million, which resulted in us recording a non-cash gain of $3.7 million for the year ended 2012. At December 31, 2013, the fair value of the warrant was estimated at $3.2 million, and we recorded a non-cash gain of $1.0 million for the year ended 2013. Based on the closing price of our stock on December 31, 2014 and the short period of time until the expiration of the GES Warrant on March 2, 2015, the warrant had no value as of December 31, 2014, and recorded a non-cash gain on warrant derivative associated with the changes in fair value of $3.2 million for the year ended December 31, 2014. The warrant expired unexercised March 2, 2015.

Income Tax Benefit

The income tax benefit recorded for the year ended December 31, 2014 amounted to $3.4 million compared to an income tax benefit of $1.9 million for the year ended December 31, 2013. The effective tax rate was 10.7% for the year ended 2014 compared to 48.5% for the year ended 2013 as a result of a permanent difference associated with the impairment of goodwill and a valuation allowance recorded in 2014 on all of our net deferred tax assets.

The income tax benefit recorded for the year ended December 31, 2013 amounted to $1.9 million compared to an income tax benefit of $5.4 million for the year ended December 31, 2012. The effective tax rate was 48.5% for the year ended 2013 compared to 52.2% for the year ended 2012 as a result lower state taxes in 2013.

Period from January 1, 2012 Through March 1, 2012 for Our Predecessor

We acquired our rig manufacturing assets from GES in March 2012. Prior to that time, we did not have meaningful operations, and as a result GES is considered our accounting predecessor and we have presented their financial information as of March 1, 2012 and the period from January 1, 2012 through March 1, 2012 in this Annual Report on Form 10-K. GES operated the predecessor business as a third-party manufacturer who manufactured and sold drilling rigs to third-party drilling contractors and recognized revenues and expenses under the percentage-of-completion method.

Revenue and Operating Expenses. During the period from January 1, 2012 through March 1, 2012, GES had two rigs under construction, which were partially complete on March 1, 2012 and ultimately acquired by us in connection with the GES Transaction. Revenues and costs during this period associated with these two rigs were accrued by GES based upon the percentage-of-completion method of accounting. During this period, GES recognized $7.7 million of revenue, including $5.8 million associated with these two drilling rigs, as well as $7.0 million of operating costs, including $5.8 million associated with these two drilling rigs. The revenues and costs not related to the two rigs under construction consisted of repair and service work and product sales to third-party drilling contractors.

Liquidity and Capital Resources

We were incorporated in November 2011 and acquired our rig manufacturing assets in March 2012. Contemporaneously with this transaction, we also acquired certain assets of RigAssetCo and completed a private placement of our common stock for net cash proceeds of approximately $98.4 million. We acquired $17.1 million in cash in connection with the RigAssetCo acquisition. The net proceeds from the private placement and the cash acquired from RigAssetCo were used to fund the construction of our rigs and for working capital purposes.

Our primary sources of capital to date have been funds received from our initial private placement of common stock, cash acquired from RigAssetCo, our revolving credit facility and our IPO. As of December 31, 2014, we had cash and cash equivalents of $10.8 million compared to $2.7 million and $37.4 million as of December 31, 2013 and 2012, respectively.

Our principal use of capital has been the construction of land drilling rigs and associated equipment required to support our growing drilling operations. Our first drilling rig was completed and began operating in May 2012. As of December 31, 2014, we had 11 completed ShaleDriller™ rigs, and three additional rigs under construction.

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) was declared effective by the Securities and Exchange Commission for our initial public offering pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 share of our common stock sold pursuant to the exercise by the underwriters in full of their Over-Allotment Option. We completed our initial public offering of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol "ICD." Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million.

Cash Flows

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Cash flows provided by (used in) operating activities	$3,809	$5,997	$(8,337)
Cash flows used in investing activities	(112,686)	(59,273)	(49,743)
Cash flows provided by financing activities	116,904	18,599	95,486
Net increase (decrease) in cash and cash equivalents	$8,027	$(34,677)	$37,406

Net Cash Provided By (Used In) Operating Activities

Cash provided by operating activities was $3.8 million for the twelve months ended December 31, 2014 compared to cash provided by operating activities of $6.0 million during the same period in 2013. 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, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense and accounts payable can significantly affect operating cash flows. Cash flows from operating activities during 2014 were lower than 2013 principally due to significant increases in investments in working capital relating to the expansion of our business in 2014.

Cash provided by operating activities was $6.0 million for the twelve months ended December 31, 2013 as compared to cash used in operating activities of $8.3 million for the same period in 2012. During 2012, our operating activities did not generate positive cash flows, reflecting the start-up nature of our operations. During that period, we only had an average of 1.29 rigs operating during the year.

Net Cash Used In Investing Activities

Cash used in investing activities was $112.7 million for the twelve months ended December 31, 2014 compared to $59.3 million during the same period in 2013. Our primary investing activities relate to the construction of new rigs as we continue to expand our operating rig fleet. Each new rig includes a full complement of drilling tubulars and inventory of spare parts and supplies. In addition, we also maintain an inventory of capital spare rig components and tubulars, which support our entire rig fleet in the event any critical component of one of our rigs is damaged or requires repair. During 2014, we spent $115.4 million on capital expenditures to fund the completion of an additional four ShaleDriller™ rigs, to upgrade one rig with a walking system, to begin the construction of an additional three ShaleDriller™ rigs scheduled to be completed in 2015, to increase our inventory of critical spares, and for maintenance capital expenditures on existing rigs. This amount was partially offset by insurance proceeds of $2.0 million and proceeds from the sale of plant, property and equipment of $0.7 million.

Cash used in investing activities was $59.3 million for the twelve months ended December 31, 2013 compared to $49.7 million during the same period in 2012. During 2013, we spent $59.7 million on capital expenditures to fund the completion of three additional ShaleDriller™ rigs, to begin construction on two additional rigs, to increase our inventory of critical spares, and for maintenance capital expenditures on existing rigs. This amount was offset by $0.4 million we received from the sale of plant, property and equipment. During 2012, we spent $66.9 million on capital expenditures to fund the completion of four ShaleDriller™ rigs, plus building our inventory of spare rig equipment and tubulars. We also had two additional rigs in various stages of construction during 2012. The expenditures were partially offset by the $17.1 million in cash we received as part of the GES Transaction and $0.04 million we received from the sale of certain equipment during 2012.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $116.9 million for the twelve months ended December 31, 2014 compared to $18.6 million during the same period in 2013. During 2014, we received net proceeds from our initial public offering of $116.5 million and made borrowings under our revolving credit facility of $137.7 million. These proceeds were offset by repayments under our revolving credit facility of $134.9 million and expenditures for deferred financing costs of $2.1 million.

Cash provided by financing activities was $18.6 million for the twelve months ended December 31, 2013 compared to $95.5 million during the same period in 2012. During 2013, borrowings under our revolving credit facility of $37.0 million were offset by repayments under our revolving credit facility of $17.2 million and expenditures for deferred financing costs of $1.2 million. During 2012, we received $98.4 million in net cash proceeds from our private placement in March 2012. These net proceeds were partially offset by repayments of debt and the repurchase of common stock.

Future Liquidity Requirements

We expect our future capital and liquidity needs to be related to funding capital expenditures for new rigs, operating expenses, expansion of our critical spare and tubular goods inventories, working capital and general corporate purposes. Using our existing cash, cash flow from operations and borrowings under our revolving credit facility, we plan to complete three rigs currently under construction, as well as fund capital expenditures associated with our inventory of critical spares and maintenance capital expenditures for our existing rigs. We currently estimate that our capital expenditures in 2015 will range between $55.0 million and $60.0 million, and will include the completion of the three drilling rigs we had under construction at December 31, 2014, the purchase of additional equipment necessary to complete our critical spare inventory and additional equipment that can be utilized in the construction of an additional Shaledriller™ rig or the outfitting of one or both of our non-walking rigs with our Shaledriller™

multi-directional walking system. We believe that our cash and cash equivalents, cash flows from operating activities and borrowings under our revolving credit facility will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next 12 months. However, should our liquidity needs increase, we may seek additional equity or debt financing.

Long-Term Debt
On May 10, 2013, we entered into a credit agreement (the "Credit Facility") with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $60.0 million revolving credit facility and an additional uncommitted$20.0 million accordion feature that allowed for future increases in the facility.

On February 21, 2014 we amended our Credit Facility in order to increase the aggregate commitments from $60.0 million to $125.0 million. The final $25.0 million of commitments under the amended Credit Facility was subject to us obtaining additional equity or indebtedness, subordinated to the Credit Facility, of at least $40.0 million (“Junior Event”). The Credit Facility, as amended, also provided for an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility.

On May 12, 2014, we amended our Credit Facility again, to expand the commitments not subject to the Junior Event from $100.0 million to $110.0 million. The amendment also adjusted the minimum EBITDA covenants contained in the Credit Facility to reflect the removal of Rig 102 from service during the pendency of its upgrade. As a result of our IPO completed on August 13, 2014, the final $25.0 million of our $125.0 million Credit Facility became available to us.

On November 5, 2014, we amended and restated our Credit Facility again to increase the commitments under the facility from $125.0 million to $155.0 million. In addition, the amendment provides for an additional uncommitted $25.0 million accordion feature that allows for future increases in borrowing availability.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to 75% of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. If a rig is idle for more than 90 days, it no longer is considered an eligible rig for purposes of our borrowing base determination. Beginning on November 5, 2015, the 75% advance rate on our eligible completed and owned drilling rigs decreases by 1.25% per quarter. The Credit Facility matures on November 5, 2018.

At our election, interest under the Credit Facility is 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, three-month LIBOR plus 1% or the federal funds effective rate plus 0.05%, plus in each case, 3.5%. We also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. The obligations under the Credit Facility are secured by all our assets and is unconditionally guaranteed by all of our future direct and indirect subsidiaries.

The Credit Facility contains various financial and operating covenants including a leverage covenant, springing fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger; consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment.

Remaining availability under the Credit Facility was $92.3 million as calculated as of December 31, 2014, based on the borrowing base formula. We are currently in compliance with all covenants under the Credit Facility and expect to remain in compliance throughout 2015.

Contractual Obligations

As of December 31, 2014, we had contractual obligations as described below. Our obligations include "off balance sheet" arrangements whereby the liabilities associated with non-cancelable operating leases and unconditional purchase obligations are not fully reflected in our balance sheets.

Contractual Obligations	2015	2016	2017	2018	2019	2020+	Total
Long-term debt	$—	$—	$—	$22,519	$—	$—	$22,519
Interest on long-term debt	1,988	2,001	2,001	1,944	—	—	7,934

Operating leases	739	427	229	49	50	—	1,494
Purchase obligations	46,841	43,248	—	—	—	—	90,089
Total contractual obligations	$49,568	$45,676	$2,230	$24,512	$50	$—	$122,036

Our long-term debt as of December 31, 2014 consisted of amounts due under our revolving credit facility. Interest on long-term debt related to our estimated future contractual interest obligations on long-term indebtedness outstanding as of December 31, 2014 under our revolving credit facility. Our operating leases relate primarily to real estate and vehicles. Our purchase obligations relate primarily to outstanding purchase orders for rig equipment or components ordered but not received.

With respect to purchase obligations in 2016, we have made progress payments of approximately $8.0 million that could be forfeited if we were to cancel these orders.

Critical Accounting Policies and Accounting Estimates

The 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 financial statements. Other significant accounting policies are summarized in Note 2 to the financial statements included in "Item 8. Financial Statements and Supplementary Data."

Capitalized Interest

We capitalize interest expense related to rig construction projects. Interest expense is capitalized during the construction period based on the weighted average interest rate of the related debt. Capitalized interest for the year ended December 31, 2014 and December 31, 2013 amounted to $1.0 million and $0.4 million, respectively. No interest expense was capitalized during the year ended December 31, 2012.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net assets acquired in connection with the Contribution Transaction. Goodwill is not amortized, but rather tested and assessed for impairment annually or more frequently if certain events or changes in circumstance indicate the carrying amount may exceed fair value. The annual test for goodwill impairment is performed following the fourth quarter of each year and begins with a qualitative assessment of whether it is “more likely than not” that the fair value of our business is less than its carrying value. If the qualitative analysis indicates that it is “more likely than not” that our business’ fair value is less than its carrying value, the resulting goodwill impairment test would consist of a two-step accounting test. The first step of the goodwill impairment test identifies the potential impairment, resulting if the fair value of a reporting unit (including goodwill) is less than its carrying amount. If during testing, it is determined that the fair value of net assets (including goodwill) exceeds its carrying amount, the goodwill of such net assets are not considered impaired and the second step of the goodwill impairment test is not applicable. However, if the fair value of net assets (including goodwill) is less than its carrying amount, we would then proceed to the second step in the goodwill impairment test. The second step includes hypothetically valuing the net assets as if they had been acquired in a business combination. Then, the implied fair value of the net assets’ goodwill is compared to the carrying value of that goodwill. If the carrying value of net assets’ goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess, not to exceed the carrying value.

Based on our analysis, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of the goodwill recorded in the Contribution Transaction (Note 1). This impairment was primarily the result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our contract drilling services and new rig construction, as well as the decline in the price of our common stock as of December 31, 2014. No goodwill impairment was recorded in 2013 or 2012.

Intangible Assets

Identified intangible assets with determinable lives have historically consisted of drilling contracts and rig manufacturing intellectual property obtained in connection with the Contribution Transaction. Intangibles related to the drilling contracts were amortized on a straight-line basis over their estimated useful lives of six months while the identified intangibles related to the rig manufacturing intellectual property were being amortized on a straight-line basis over their estimated useful lives of ten years.

The identifiable intangibles are evaluated for impairment at the end of each reporting period if events occur or circumstances change that would more likely than not reduce the fair value of the intangibles below their carrying amounts. During the fourth quarter of 2014, as a result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our drilling services and new rig construction, we re-evaluated the cost efficiencies to be realized in future rig construction. As a result of this evaluation, and current economic environment, management reassessed the remaining useful life of our rig manufacturing intellectual property reducing it from 7.2 remaining years to zero years. As a result of this revised estimate, we recorded additional amortization expense of $19.6 which has been included in "Goodwill impairment and other charges" in the accompanying statement of operations.

Revenue and Cost Recognition

Our revenues are principally derived from contract drilling services, as well as product sales, and field services provided to third parties, and transitional services provided to GES pursuant to a transitional services agreement (the “Transition Services Agreement”) entered into in connection with the Contribution Agreement (Note 1 to the financial statements included in "Item 8. Financial Statements and Supplementary Data").

We record contract drilling revenue for daywork contracts daily as work progresses, assuming collectability is assured. Daywork drilling contracts provide that revenue is earned daily based on a specified rate per day and the term of the contract which can be for a specific period of time or a specified number of wells. 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 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.

Depreciation and Amortization

We account for the depreciation of property, plant and equipment using the straight-line method over the estimated useful lives of the assets considering the estimated salvage value of the related property, plant and equipment. Depreciation of property, plant and equipment is recorded based on the following estimated useful lives:

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

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 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 statement of operations.

Stock-Based Compensation

We record compensation expense over the applicable vesting 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 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 balance sheets. See "- Contractual Obligations" for additional information.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update to provide guidance on the reporting of discontinued operations and the disclosures related to disposals of components of an entity. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. This guidance is effective for interim and annual periods that begin after December 15, 2014. Early application is permitted. We are currently evaluating the impact this will have on our consolidated financial statements. At this time, we do not believe it will materially impact our financial statements.

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. This guidance is effective for interim and annual periods beginning after December 15, 2016. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. This guidance is effective for interim and annual periods beginning after December 15, 2015. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In August 2014, the FASB issued guidance requiring management to perform interim and annual assessments of an entity’s ability to continue as a going-concern within one year of the date the financial statements are issued. The standard also provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. An entity must provide certain disclosures if there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going-concern. Management’s evaluation should be based on relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued. The new guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We do not expect that the adoption of this guidance will have an impact on our consolidated financial statements or disclosures.

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, 2014 included $22.5 million of floating-rate debt attributed to borrowings at an average interest rate of 6.0%. As a result, our annual interest cost in 2015 will fluctuate based on short-term interest rates.

The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.60%) would be approximately $0.1 million annually based on the floating-rate debt and other obligations outstanding at December 31, 2014; however, there are no assurances that possible rate changes would be limited to such amounts.

Commodity Price Risk

The demand for contract drilling services is a result of E&P companies spending money to explore and develop drilling prospects in search of oil and natural gas. This customer spending is driven by their cash flow and financial strength, which is affected by trends in crude oil and natural gas commodity prices. Crude oil prices are determined by a number of factors including supply and demand, worldwide economic conditions and geopolitical factors. Crude oil and natural gas prices have historically been volatile and very difficult to predict. This volatility can lead many E&P companies to base their capital spending on much more conservative estimates of commodity prices. As a result, demand for contract drilling services is not always purely a function of the movement of current commodity prices. Oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $49.84 per barrel during the last week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). Further declines in oil prices, for a prolonged period, could adversely impact the level of exploration and production activity by our customers and the demand for our services.

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, such as we are currently experiencing, 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 and results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Independence Contract Drilling, Inc.:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Independence Contract Drilling at December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Houston, TX
March 16, 2015

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

	December 31, 2014	December 31, 2013
Assets		
Cash and cash equivalents	$10,757	$2,730
Accounts receivable, net	19,127	9,089
Inventory	2,124	1,128
Vendor advances	—	6,168
Deferred taxes	323	—
Prepaid expenses and other current assets	3,969	2,042
Total current assets	36,300	21,157
Property, plant and equipment, net	250,498	129,488
Goodwill	—	11,007
Other intangible assets, net	—	22,357
Other long-term assets, net	2,749	959
Total assets	$289,547	$184,968
Liabilities and Stockholders' Equity		
Liabilities		
Accounts payable	$21,993	$9,061
Accrued liabilities	6,970	4,167
Deferred taxes	—	149
Income taxes payable	408	157
Total current liabilities	29,371	13,534
Long-term debt	22,519	19,780
Warrant derivative liability	—	3,189
Other long-term liabilities, net	598	—
Deferred taxes	323	3,593
Total liabilities	52,811	40,096
Commitments and contingencies (Note 12)		
Stockholders' equity		
Common stock, $0.01 par value, 100,000,000 shares authorized; 24,714,344 and 12,464,625 issued, respectively; 24,629,333 and 12,397,900 outstanding, respectively	246	124
Additional paid-in capital	272,750	152,615
Accumulated deficit	(35,289)	(7,121)
Treasury shares, at cost, 85,011 shares	(971)	(746)
Total stockholders' equity	236,736	144,872
Total liabilities and stockholders' equity	$289,547	$184,968

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

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

	Year Ended December 31,		
	2014	2013	2012
Revenues	$70,347	$42,786	$15,123
Costs and expenses			
Operating costs	42,654	28,401	15,400
Selling, general and administrative	12,222	8,911	7,813
Depreciation and amortization	16,181	10,186	5,904
Goodwill impairment and other charges	30,627	—	—
Asset impairment, net of insurance recoveries	1,711	—	—
(Gain) loss on disposition of assets	19	(55)	—
Total cost and expenses	103,414	47,443	29,117
Operating loss	(33,067)	(4,657)	(13,994)
Interest expense	(1,648)	(257)	(10)
Gain on warrant derivative	3,189	1,035	3,655
Loss before income taxes	(31,526)	(3,879)	(10,349)
Income tax benefit	(3,358)	(1,882)	(5,401)
Net loss	$(28,168)	$(1,997)	$(4,948)
Loss per share:			
Basic	$(1.65)	$(0.16)	$(0.49)
Diluted	$(1.65)	$(0.16)	$(0.49)
Weighted average number of common shares outstanding:			
Basic	17,078	12,179	10,141
Diluted	17,078	12,179	10,141

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

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Stockholders' Equity
	(in thousands, except share amounts)					
Balances at January 1, 2012	158	$—	$1	$(176)	$—	$(175)
Stock issued—contribution transaction	3,923,038	39	49,936	—	—	49,975
Stock issued—144A offering, net	8,264,323	83	98,275	—	—	98,358
Restricted stock issued	246,490	2	(2)	—	—	—
Restricted stock forfeitures	(58,090)	—	—	—	—	—
Stock-based compensation	—	—	2,237	—	—	2,237
Purchase of treasury stock	(66,725)	(1)	—	—	(746)	(747)
Net loss	—	—	—	(4,948)	—	(4,948)
Balances at December 31, 2012	12,309,194	$123	$150,447	$(5,124)	$(746)	$144,700
Restricted stock issued	88,706	1	(1)	—	—	—
Stock-based compensation	—	—	2,169	—	—	2,169
Net loss	—	—	—	(1,997)	—	(1,997)
Balances at December 31, 2013	12,397,900	$124	$152,615	$(7,121)	$(746)	$144,872
Restricted stock issued	749,720	7	(7)	—	—	—
Public offering, net of offering costs of $10,042	11,500,000	115	116,343	—	—	116,458
Purchase of treasury stock	(18,287)	—	—	—	(225)	(225)
Stock-based compensation	—	—	3,799	—	—	3,799
Net loss				(28,168)		(28,168)
Balances at December 31, 2014	24,629,333	$246	$272,750	$(35,289)	$(971)	$236,736

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

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

	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net loss	$(28,168)	$(1,997)	$(4,948)
Adjustments to reconcile net loss to net cash used in operating activities			
Depreciation and amortization	16,181	10,186	5,904
Goodwill impairment and other charges	30,627	—	—
Asset impairment, net of insurance recoveries	1,711	—	—
Stock-based compensation	3,143	1,751	1,883
Gain on warrant derivative	(3,189)	(1,035)	(3,655)
(Gain) loss on disposition of assets	19	(55)	—
Deferred taxes	(3,742)	(2,043)	(5,401)
Amortization of deferred financing costs	668	251	—
Bad debt expense	123	93	256
Changes in assets and liabilities			
Accounts receivable	(10,161)	(3,802)	(5,638)
Inventory	(1,356)	(240)	(889)
Vendor advances	—	(3,977)	546
Prepaid expenses and other assets	(1,313)	(856)	(629)
Accounts payable and accrued liabilities	(985)	6,978	3,402
Income taxes payable	251	157	—
Related party receivable	—	586	832
Net cash provided by (used in) operating activities	3,809	5,997	(8,337)
Cash flows from investing activities			
Cash acquired in contribution transaction	—	—	17,082
Purchases of property, plant and equipment	(115,388)	(59,689)	(66,864)
Proceeds from insurance claims	2,038	—	—
Proceeds from the sale of assets	664	416	39
Net cash used in investing activities	(112,686)	(59,273)	(49,743)
Cash flows from financing activities			
Borrowings under credit facility	137,681	36,986	—
Repayments under credit facility	(134,942)	(17,206)	—
Repayment of other debt	—	—	(2,125)
Initial public offering proceeds, net of offering costs of $10,042	116,458	—	—
Deferred financing costs	(2,068)	(1,181)	—
Purchase of treasury stock	(225)	—	(747)
Proceeds from 144A offering, net	—	—	98,358
Net cash provided by financing activities	116,904	18,599	95,486
Net increase (decrease) in cash and cash equivalents	8,027	(34,677)	37,406
Cash and cash equivalents			
Beginning of period	2,730	37,407	1
End of period	$10,757	$2,730	$37,407

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

Independence Contract Drilling, Inc.
Notes to Financial Statements

1. Nature of Operations
Independence Contract Drilling, Inc. (“we,” “us,” “our,” the “Company” or “ICD”) was 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 construct, own and operate a premium fleet comprised entirely of newly constructed, technologically advanced, custom designed ShaleDriller™ rigs that are specifically engineered and designed to optimize the development of our customers’ most technically demanding oil and gas properties. Our first rig began drilling in May 2012.

Our standardized fleet consisted of fourteen premium rigs as of December 31, 2014. Of these fourteen rigs, three are currently under construction and scheduled for completion in 2015. Currently, twelve of our fourteen rigs contain our integrated multi-directional walking system that is specifically designed to optimize pad drilling for our customers.

Our business depends on the level of exploration and production activity by oil and gas companies operating in the U.S., and in particular, the regions where we actively market our contract drilling services. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and 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 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 U.S. and the regions where we market our contract drilling services, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect our business.

In this regard, oil prices declined significantly during the second half of 2014 and have continued to decline in 2015. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, as low as $44.08 per barrel in late January 2015 and around $49.84 per barrel during the last week in February 2015 (WTI spot price as reported by the United States Energy Information Administration). As a result of the decline in oil prices, our industry is now experiencing a severe downturn. Market conditions remain very dynamic and are changing quickly. Although the magnitude as well as the duration of this downturn are not yet known, we believe that 2015 will be a very challenging year for our industry.

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

As a result of this deterioration in market conditions, our customers are principally focused on their most economic wells and on maintaining their most cost efficient operations that deliver the overall lowest cost of producing their wells. As a result, operators are focusing more of their capital spending on horizontal drilling programs on multi-well pads compared to vertical drilling and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe this rapid market deterioration has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads.

Although we believe that the current market downturn is rapidly increasing the focus of our customers towards the use of premium drilling rigs such as our ShaleDriller™, and that premium operations such as ours will be less affected by the downturn relative to operations conducted by legacy fleets, the rapid pace and level of the market decline has negatively impacted pricing, utilization and contract tenors for premium rigs, including our ShaleDriller™ rig. During 2014, we have operated our premium drilling fleet with 99.7% contractual utilization, but we do not expect to maintain this level of utilization while this current market downturn continues. Since December 31, 2014, one of our non-walking rigs has become idle and we are evaluating whether to continue marketing this rig or to upgrade it with our multi-directional walking system. We also have four other drilling rigs operating under contracts with terms expiring during the first half of 2015. We expect to market these rigs at substantially lower dayrates than their expiring contracts and at lower contractual utilization rates than where we historically have operated, and there can be no assurance that these rigs will remain operating at profitable levels.

Damage Sustained on Rig 102

On March 9, 2014, one of our non-walking drilling rigs suspended drilling operations due to damage to the rig's mast and other operating equipment. We believe the cost to repair and replace this equipment is covered by insurance, subject to
a $250,000 deductible. While under repair, we upgraded this rig by adding a substructure and other equipment that includes a multi-directional walking system. The cost of the upgrades were not covered by insurance. The repairs and upgrades were completed in October 2014 when the upgraded rig recommenced operations. We recorded an asset impairment charge of $4.7 million during the three months ended March 31, 2014, representing a preliminary estimate of the damage sustained to the rig. During the three months ended June 30, 2014, we recorded approximately $2.3 million in insurance recoveries related to repairing damage to the rig ($2.0 million) as well as the recovery of certain out-of-pocket expenses ($0.3 million), for which we had received a partial proof of loss from the insurance company. As of September 30, 2014, all of the $2.3 million had been collected. In the fourth quarter of 2014, we recorded an additional $1.6 million in insurance recoveries related to repairing damage to the rig ($1.0 million) as well as the recovery of certain out-of-pocket expenses ($0.6 million), for which we had received a second partial proof of loss from the insurance company. We expect to record additional insurance recoveries estimated at approximately $1.3 million in the first quarter of 2015 when the final proof of loss is obtained.

Stock Split

On July 14, 2014, our board of directors approved a resolution to effect a 1.57-for-1 stock split of our common stock in the form of a stock dividend. The dividend was distributed on July 24, 2014 to holders of record as of July 21, 2014. The earnings per share information and all common stock information in these financial statements have been retroactively restated for all periods presented to reflect this stock split.

Initial Public Offering

On August 7, 2014, our registration statement on Form S-1 (File No. 333-196914) (the Form S-1) was declared effective by the Securities and Exchange Commission for our initial public offering pursuant to which we sold an aggregate of 11,500,000 shares of our common stock at a price to the public of $11.00 per share, which included 1,500,000 shares of our common stock sold pursuant to the exercise by the underwriters in full of their Over-Allotment Option. We completed our initial public offering of 10,000,000 shares of our common stock on August 13, 2014 and subsequently closed the issuance and sale of the additional 1,500,000 shares of our common stock pursuant to the Over-Allotment Option on August 29, 2014. Our common stock trades on the New York Stock Exchange under the ticker symbol "ICD." Net proceeds from the offering were $116.5 million after deducting $7.6 million of underwriting discounts and commissions, as well as legal, accounting, printing and other expenses directly associated with the offering totaling $2.4 million. All of the outstanding borrowings on our revolving credit facility were repaid immediately following the offering.

Contribution Transactions

On March 2, 2012, certain contribution transactions were completed pursuant to an asset contribution and share subscription agreement (the "Contribution Agreement") that involved the Company acquiring certain assets and liabilities of Global Energy Services Operating, LLC ("GES"), and Independence Contract Drilling LLC ("RigAssetCo"). Simultaneously with the closing of a private placement of the Company's common stock, (the "Private Placement") (i) GES contributed all of its rig manufacturing and related field service assets to us in exchange for $20.0 million of our common stock, the issuance of a warrant to purchase 2.2 million shares of our common stock (the "GES Warrant") and the assumption by us of $2.1 million of long-term indebtedness; and (ii) RigAssetCo contributed substantially all of its assets to us in exchange for $29.98 million, payable in shares of our common stock (collectively, the "Contribution Transaction"). The assets contributed by RigAssetCo included (i) approximately $28.6 million of cash, reduced by cash payments made for management compensation, deposits on the manufacture of two drilling rigs and related equipment and (ii) two day rate drilling contracts. The common stock issued pursuant to the terms of the Contribution Agreement, as well as the exercise price under the GES Warrant, were determined using the same price as the stock issued in the "Private Placement." In conjunction with the completion of the Contribution Transaction, GES was determined to be the predecessor for accounting purposes.

The transactions contemplated by the Contribution Agreement were structured with the intent that they qualify as a single tax-free contribution under Section 351 of the Internal Revenue Code of 1986. As a result, we did not receive a "step up" in taxable basis of the assets being transferred to us, but rather the historical tax basis of the assets contributed by GES and RigAssetCo were carried forward.

A summary of the assets acquired and liabilities assumed in connection with the GES transaction is set forth below:

Purchase price	
Common stock issued (1,570,000 shares at approximately $12.74 per share)	$20,000
GES warrant	7,879
Total purchase price	$27,879
Purchase price allocation	
Cash	$7,893
Accounts receivable	1,426
Vendor deposits	2,737
Land, buildings and equipment	3,773
Construction in progress	6,374
Intangibles	
Rig manufacturing intellectual property	27,376
Goodwill	10,318
Total assets acquired	59,897
Current liabilities	19,252
Debt	2,125
Deferred taxes	10,641
Total liabilities assumed	32,018
Allocated purchase price	$27,879

The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair value on the transaction date. The allocation of fair value was based on third party appraisals and management's estimates. The fair value of the GES warrant was estimated based upon the share price on the valuation date, expected volatility, risk-free interest rate and management's assumptions regarding the likelihood of a future repricing of these warrants pursuant to the adjustment provision. The fair value calculation for the GES warrant included the following assumptions:

Risk-free interest rate	0.64	%
Expected volatility	40	%
Dividend yield	—	
Expected term	3.0 years	

Risk-Free Interest Rate

The risk-free interest rate is based on U.S. Treasury securities with maturities that are the same as the expected term of the option.

Expected Volatility Rate

Expected volatilities are based on an analysis of volatilities for publicly traded companies engaged in the contract drilling business.

Expected Term

The expected term of the warrant represents the three year contractual term. The rig manufacturing intellectual property acquired in the GES transaction includes all rig designs, drawings, specifications and rig operation software and programming necessary for the Company to manufacture its various ShaleDriller™ rigs. The rig manufacturing intellectual property was valued using an avoided cost methodology that assumed $2.5 million in cost savings for each rig constructed as compared to buying rigs constructed by third parties. This savings is then discounted over our probability adjusted, planned rig construction schedule. This intellectual property was being amortized over a ten year period.

A term loan in the amount of $2.1 million was assumed in connection with the GES transaction and fully repaid on March 2, 2012.

A summary of the assets acquired and liabilities assumed in connection with the RigAssetCo transaction is set forth below:

Purchase price	
Common stock issued (2,353,038 shares at approximately $12.74 per share)	$29,975
Purchase price allocation	
Cash	9,236
Deposits	19,131
Intangibles	
Third party drilling contracts	1,511
Goodwill	689
Total assets acquired	30,567
Deferred taxes	592
Total liabilities assumed	592
Allocated purchase price	$29,975

The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair value on the transaction date. The allocation of fair value was based on third party appraisals and management's estimates. Third party drilling contracts represent an intangible asset that has a separate value apart from both the purchased tangible assets and other assets acquired in the RigAssetCo transaction. Two third party drilling contracts were acquired from RigAssetCo in the transaction, each with a term of six months with an optional six month renewal. The drilling contracts were valued using a discounted cash flow methodology and were amortized using the straight-line method over six months. The drilling contract intangible assets were fully amortized as of December 31, 2012.

Based on the purchase price allocations of the GES transaction and the RigAssetCo transaction it was determined that the fair values of the net assets acquired were less than the purchase price, resulting in the recording of $11.0 million in goodwill in total. This goodwill, all of which is nondeductible for tax purposes, was largely the result of efficiencies associated with constructing rigs for internal use.

Private Placement

As a condition of the closing of the Contribution Transaction, we completed the Private Placement of our common stock, pursuant to Rule 144A of the Securities Act of 1933, as amended. Pursuant to the Private Placement, a total of 8,264,323 shares of our common stock were issued at an offering price of $12.74 per share.

The following table summarizes the net proceeds we received in the Private Placement, after the deduction of applicable costs and expenses:

	(in thousands)	
Common stock (8,264,323 shares at approximately $12.74 per share)	$105,278	
Less: Initial purchasers discount	(5,419	)
Other expenses	(1,501	)
Net proceeds	$98,358	

Other expenses consisted of legal, accounting, printing and other closing costs directly associated with the Private Placement.

2. Summary of Significant Accounting Policies

Basis of Presentation

These audited financial statements include all the accounts of ICD, and 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 or 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 individual accounts. Receivables are written off when they are deemed to be uncollectible. The allowance for doubtful accounts totaled $0.1 million and $0.1 million as of December 31, 2014 and December 2013, respectively.

Inventory

Inventory is stated at lower of cost or market and consists primarily of replacement parts and 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	5	- 20 years
Machinery, equipment and other	3	- 7 years
Vehicles	2	- 5 years
Software	2	- 7 years

We own substantially all of our rig assembly yard and corporate offices located in Houston, Texas. We lease a number of vehicles and land for equipment and inventory storage. 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 do not currently have any capital leases.

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 to be 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 such assets are considered to be impaired, an impairment charge is recorded in the amount by which the carrying amount of the assets exceeds their estimated fair value determined using discounted cash flows. Other than the impairment associated with the damage to one of our non-walking rigs (Note 1), no impairments were recorded for the years ended December 31, 2014 or December 31, 2013.

Construction in progress represents the costs incurred for drilling rigs that remain 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 expense related to rig construction projects. Interest expense is capitalized during the construction period based on the weighted average interest rate of the related debt. Capitalized interest amounted to $1.0 million, $0.4 million and $0.0 million during the year ended December 31, 2014, 2013 and 2012, respectively.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net assets acquired in connection with the Contribution Transaction. Goodwill is not amortized, but rather tested and assessed for impairment annually or more frequently if certain events or changes in circumstance indicate the carrying amount may exceed fair value. The annual test for goodwill impairment is performed during the fourth quarter of each year and begins with a qualitative assessment of whether it is “more likely than not” that the fair value of our business is less than its carrying value. If the qualitative analysis indicates that it is “more likely than not” that our business’ fair value is less than its carrying value, the resulting goodwill impairment test would consist of a two-step accounting test. The first step of the goodwill impairment test identifies the potential impairment, resulting if the fair value of a reporting unit (including goodwill) is less than its carrying amount. If during testing, it is determined that the fair value of net assets (including goodwill) exceeds its carrying amount, the goodwill of such net assets are not considered impaired and the second step of the goodwill impairment test is not applicable. However, if the fair value of net assets (including goodwill) is less than its carrying amount, we would then proceed to the second step in the goodwill impairment test. The second step includes hypothetically valuing the net assets as if they had been acquired in a business combination. Then, the implied fair value of the net assets’ goodwill is compared to the carrying value of that goodwill. If the carrying value of net assets’ goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess, not to exceed the carrying value.

Our analysis considered the discounted cash flow method, market capitalization and the guideline company method. Based on this analysis, we recorded a goodwill impairment of $11.0 million for the year ended December 31, 2014, which represents the impairment of 100% of the goodwill recorded in the Contribution Transaction (Note 1). This impairment was primarily the result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our contract drilling services and new rig construction, as well as the decline in the price of our common stock as of December 31, 2014. No goodwill impairment was recorded in 2013 or 2012.

Intangible Assets

Identified intangible assets with determinable lives have historically consisted of drilling contracts and rig manufacturing intellectual property obtained in connection with the Contribution Transaction. Intangibles related to the drilling contracts were amortized on a straight-line basis over their estimated useful lives of six months while the identified intangibles related to the rig manufacturing intellectual property were being amortized on a straight-line basis over their estimated useful lives of ten years.

The identifiable intangibles are evaluated for impairment at the end of each reporting period if events occur or circumstances change that would more likely than not reduce the fair value of the intangibles below their carrying amounts. During the fourth quarter of 2014, as a result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our drilling services and new rig construction, we re-evaluated the cost efficiencies to be realized in future rig construction. As a result of this evaluation, and current economic environment, management reassessed the remaining useful life of our rig manufacturing intellectual property reducing it from 7.2 years, to zero years. As a result of this revised estimate, we recorded additional amortization expense of $19.6 million which has been included in "Goodwill impairment and other charges" in the accompanying statement of operations.

Financial Instruments and Fair value

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

Our financial instruments that are subject to fair value measurements consist of the GES Warrant and long-term debt. The GES Warrant, which expired on March 2, 2015, contains a provision that protects the holder from a decline in the issue price of our common stock, or a “down-round” provision. Down-round provisions reduce the exercise or conversion price of a warrant or convertible instrument if a company either issues equity shares for a price that is lower than the exercise or conversion price of those instruments or issues new warrants or convertible instruments that have a lower exercise or conversion price. As a result of this provision, we account for this warrant as a liability. Following our initial public offering on August 13, 2014 and the full exercise of the Over-Allotment Option on August 29, 2014, the exercise price of the GES Warrant was reduced from $12.74 per share to $11.37 per share.

In accordance with Accounting Standards Codification 815 “Accounting for Derivative Instruments and Hedging Activities,” as amended, this warrant derivative liability is marked-to-market each reporting period, with a corresponding non-cash gain or loss charged to the current period. 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 warrant liability was recorded at fair value using Level 3 inputs as of December 31, 2013. Significant Level 3 inputs used to calculate the fair value of the warrant include the estimated share price on the valuation date, expected volatility, risk-free interest rate and management's assumptions regarding the likelihood of a future repricing of these warrants pursuant to the adjustment provision. Due to the initial public offering completed in August 2014, the warrant liability was recorded at fair value using Level 1 inputs (our share price) for the year ended December 31, 2014.

Based on the price of our stock on December 31, 2014 and the short period of time until the expiration of the GES Warrant on March 2, 2015, the warrant had no value as of December 31, 2014. The fair value of the GES warrant as of December 31, 2013 was $3.2 million. We recorded non-cash gains on warrant derivative associated with the changes in fair value of $3.2 million, $1.0 million and $3.7 million for the years ended December 31, 2014, December 31, 2013 and December 31, 2012, respectively.

The following provides a reconciliation of financial liabilities measured at fair value on a recurring basis using Level 3 inputs:

	December 31,		
	2014	2013	2012
	(in thousands)		
Beginning balance	$3,189	$4,224	$—
Issuance of GES warrant	—	—	7,879
Gain on warrant derivative	(3,189)	(1,035)	(3,655)
Ending balance	$—	$3,189	$4,224

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, or on the amount of future cash flows associated with the debt, discounted using our current borrowing rate for comparable debt instruments. The estimated fair value of our long-term debt totaled $22.9 million and $18.6 million as of December 31, 2014 and 2013, respectively, compared to a carrying amount of $22.5 million and $19.8 million as of December 31, 2014 and 2013, respectively.

Fair value measurements were applied with respect to our non-financial assets and liabilities measured on a nonrecurring basis, which would consist of measurements primarily related to goodwill, intangible assets and other long-lived assets, and assets acquired and liabilities assumed in the Contribution Transaction (Note 1). There were no transfers between levels of the hierarchy for the years ended December 31, 2014 and 2013.

Revenue and Cost Recognition

Our revenues are principally derived from contract drilling services, as well as product sales, and field services provided to third parties, and transitional services provided to GES pursuant to a transitional services agreement (the "Transition Services Agreement") entered into in connection with the Contribution Agreement (Note 1).

We record contract drilling revenue for daywork contracts daily as work progresses, assuming collectability is assured. Daywork drilling contracts provide that revenue is earned daily based on a specified rate per day and the term of the contract which can be for a specific period of time or a specified number of wells. 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 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.

Stock-Based Compensation

We record compensation expense over the applicable vesting 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 statement 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 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 statement of operations.

Use of Estimates

The preparation of 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.

Recently Issued Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update to provide guidance on the reporting of discontinued operations and the disclosures related to disposals of components of an entity. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. This guidance is effective for interim and annual periods that begin after December 15, 2014. Early application is permitted. We are currently evaluating the impact this will have on our consolidated financial statements. At this time, we do not believe it will materially impact our financial statements.

In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. This guidance is effective for interim and annual periods beginning after December 15, 2016. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. This guidance is effective for interim and annual periods beginning after December 15, 2015. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In August 2014, the FASB issued guidance requiring management to perform interim and annual assessments of an entity's ability to continue as a going-concern within one year of the date the financial statements are issued. The standard also provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. An entity must provide certain disclosures if there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going-concern. Management's evaluation should be based on relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued. The new guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We do not expect that the adoption of this guidance will have an impact on our consolidated financial statements or disclosures.

3. Inventory

Inventory consisted of the following:

	December 31, 2014	2013
	(in thousands)	
Raw materials and purchased components	$2,124	$1,128

We determined that no reserve for obsolescence was needed at December 31, 2014 or December 31, 2013. No inventory obsolescence expense was recognized during the year ended December 31, 2014 and December 31, 2013.

4. Property, Plant and Equipment, Net

Property, plant, and equipment consisted of the following:

	December 31, 2014	2013
	(in thousands)	
Land	$1,344	$1,344
Buildings	2,025	1,723
Drilling rigs and related equipment	227,758	132,226
Machinery, equipment and other	1,287	1,595
Vehicles	266	374
Software	714	743
Construction in progress	38,974	954
	$272,368	$138,959
Less: Accumulated depreciation	(21,870)	(9,471)
	$250,498	$129,488

Repairs and maintenance expense included in operating costs in our statement of operations totaled $7.4 million, $3.9 million and $1.2 million for the years ended December 31, 2014, December 31, 2013 and December 31, 2012, respectively. Depreciation expense was $13.4 million, $7.5 million and $2.1 million for the years ended December 31, 2014, December 31, 2013 and December 31, 2012, respectively.

5. Intangible Assets

Intangible assets consisted of the following (in thousands except for estimated useful lives):

	December 31, 2014			
	Estimated Useful Lives	Gross Amount	Accumulated Amortization	Net Book Value
Rig manufacturing intellectual property	10 years	$27,376	$27,376	$—

	December 31, 2013			
	Estimated Useful Lives	Gross Amount	Accumulated Amortization	Net Book Value
Rig manufacturing intellectual property	10 years	$27,376	$5,019	$22,357

The identifiable intangibles are evaluated for impairment at the end of each reporting period if events occur or circumstances change that would more likely than not reduce the fair value of the intangibles below their carrying amounts. During the fourth quarter of 2014, as a result of the significant downturn in industry conditions in late 2014 and the related uncertainty regarding demand for our drilling services and new rig construction, we re-evaluated the cost efficiencies to be realized in future rig construction. As a result of this evaluation, and current economic environment, management reassessed the remaining useful life of our rig manufacturing intellectual property reducing it from 7.2 years, to zero years. As a result of this revised estimate, we recorded additional amortization expense of $19.6 million which has been included in "Goodwill impairment and other charges" in the accompanying statement of operations.

Amortization expense recorded in the caption depreciation and amortization in our statement of operations was was $2.7 million, $2.7 million and $3.8 million for the year ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively.

6. Supplemental Balance Sheet and Cash Flow Information

Accrued liabilities consisted of the following:

	December 31,	
(in thousands)	2014	2013
Accrued salaries and other compensation	$2,710	$1,868
Insurance	488	485
Deferred mobilization revenues	1,281	684
Property, sales and other tax	1,710	787
Other	781	343
	$6,970	$4,167

Supplemental cash flow information:

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Supplemental disclosure of cash flow information			
Cash paid during the period for interest	$1,907	$196	$10
Cash paid during the period for taxes	135	—	—
Supplemental disclosure of non-cash investing and financing activity			
Stock-based compensation capitalized as property, plant and equipment	656	418	354
Purchases of property, plant and equipment in accounts payable	19,292	1,974	8,262
Common stock issued in connection with the contribution transactions	—	—	49,975
Warrant issued in connection with the contribution transactions	—	—	7,879

7. Long-term Debt

On May 10, 2013, we entered into a credit agreement (the “Credit Facility”) with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $60.0 million revolving credit facility and an additional uncommitted$20.0 million accordion feature that allowed for future increases in the facility.

On February 21, 2014 we amended our Credit Facility in order to increase the aggregate commitments from $60.0 million to $125.0 million. The final $25.0 million of commitments under the amended Credit Facility was subject to us obtaining additional equity or indebtedness, subordinated to the Credit Facility, of at least $40.0 million (“Junior Event”). The Credit Facility, as amended, also provided for an additional uncommitted $25.0 million accordion feature that allows for future increases in the facility.

On May 12, 2014, we amended our Credit Facility again, to expand the commitments not subject to the Junior Event from $100.0 million to $110.0 million. The amendment also adjusted the minimum EBITDA covenants contained in the Credit

Facility to reflect the removal of Rig 102 from service during the pendency of its upgrade. As a result of our initial public offering completed on August 13, 2014, the final $25.0 million of our $125.0 million Credit Facility became available to us.

On November 5, 2014, we amended and restated our Credit Facility again to increase the commitments under the facility from $125.0 million to $155.0 million. In addition, the amendment provides for an additional uncommitted $25.0 million accordion feature that allows for future increases in borrowing availability.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to 75% of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. Beginning on November 5, 2015, the 75% advance rate on our eligible completed and owned drilling rigs decreases by 1.25% per quarter. The Credit Facility matures on November 5, 2018.

At our election, interest under the Credit Facility is 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, three-month LIBOR plus 1% or the federal funds effective rate plus 0.05%, plus in each case, 3.5%. We also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. The obligations under the Credit Facility are secured by all our assets and is unconditionally guaranteed by all of our future direct and indirect subsidiaries.

The Credit Facility contains various financial and operating covenants including a leverage covenant, springing fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger; consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment.

Remaining availability under the Credit Facility was $92.3 million as calculated as of December 31, 2014, based on the borrowing base formula. We are currently in compliance with all covenants under the Credit Facility and expect to remain in compliance throughout 2015.

8. Income Taxes

The components of the income tax benefit are as follows:

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Current:			
Federal	$—	$4	$—
State	384	157	—
	384	161	—
Deferred:			
Federal	$(3,656)	$(1,506)	$(4,818)
State	(86)	(537)	(583)
	(3,742)	(2,043)	(5,401)
Income tax benefit	$(3,358)	$(1,882)	$(5,401)

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The following is a reconciliation of the income tax benefit that was recorded compared to taxes provided at the U.S. statutory rate:

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Income tax benefit at the statutory federal rate (35%)	$(11,034)	$(1,358)	$(3,622)
Goodwill impairment	3,852	—	—
Warrant	(1,116)	(362)	(1,279)
Nondeductible expenses	143	243	143
Valuation allowance	4,449	—	(60)
State taxes, net of federal benefit	105	(436)	(574)
Other	243	31	(9)
Income tax benefit	$(3,358)	$(1,882)	$(5,401)
Effective tax rate	10.7%	48.5%	52.2%

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)	2014	2013
Deferred assets		
Bad debts	$46	$33
Stock-based compensation	2,061	1,326
Accrued vacation and other	76	—
Deferred mobilization cost	667	245
Net operating losses	32,199	31,416
Total net deferred tax assets	35,049	33,020
Deferred liabilities		
Prepaids	$(300)	$(428)
Property, plant and equipment	(30,300)	(28,325)
Intangible assets	—	(8,009)
Total net deferred tax liabilities	(30,600)	(36,762)
Valuation allowance	$(4,449)	$—
Net deferred tax liability	$—	$(3,742)

At December 31, 2014, we had a total net operating loss (NOL) carryforward of $90.7 million of federal NOL carryforwards, which begin expiring in 2032.

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. 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, 2014, we had no unrecognized tax benefits. We file income tax returns in the U.S. and in various state jurisdictions. With few exceptions, we are subject to U.S. federal, state and local income tax examinations by tax authorities for tax periods 2011 and forward. Our federal and state tax returns for 2011 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.

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In assessing the realizability of the deferred tax assets, management considers 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. During 2014, 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 in the amount of $4.4 million.

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.

9. 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 of 2014. 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 3,454,000 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, 2014, approximately 1,124,044 shares were available for future awards.

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

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Compensation cost recognized:			
Stock options	$1,133	$1,077	$1,549
Restricted stock and restricted stock units	2,666	1,092	688
Total stock-based compensation	$3,799	$2,169	$2,237

Approximately $0.7 million, $0.4 million and $0.4 million in stock-based compensation was capitalized in connection with rig construction activity during the year ended December 31, 2014, December 31, 2013 and December 2012, respectively.

Stock Options

Certain options were granted on March 2, 2012 and began vesting on their date of grant, with 25% of such options vesting on the grant date, and 25% of such options vesting on each anniversary thereafter until fully vested on March 2, 2015. A subsequent grant of 15,700 options was made in August 2012, one third of which vest on each anniversary of the grant date over three years. In December 2012, we granted an additional 229,613 stock options that vest over five years in three equal tranches commencing on the third year anniversary date and each year thereafter. No options were exercised during the years ended December 31, 2014, 2013 or 2012. 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.

In February 2013, we granted an additional 119,320 stock options that vest over four years. No stock options were granted during the year ended December 31, 2014.

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 fair value calculations for options granted are based on the following weighted-average assumptions:

	Year Ended December 31,			
	2013		2012	
Risk-free interest rate	0.83	%	1.05	%
Expected volatility	40	%	40	%
Dividend yield	—		—	

Expected term	5.0 years	5.8 years

Risk-Free Interest Rate

The risk-free interest rate is based on U.S. Treasury securities with maturities that are the same as the expected term of the option.

Expected Volatility Rate

As we did not have a trading history in 2013 or 2012, we were required to estimate the potential volatility of our common stock price. The volatility calculation was based on the average volatility of a representative sample of four companies (the "Sample Companies") that management believes to be engaged in the land contract drilling business. We referred to the average volatility of the Sample Companies because management believed that the average volatility of such companies was a reasonable benchmark to use in estimating the expected volatility of our common stock.

Expected Dividend Yield

We have no plans to pay dividends in the foreseeable future.

Expected Term

The expected term of the options granted represents the period of time that they are expected to be outstanding.

Based on these calculations, the weighted-average fair value per option granted to acquire a share of common stock was $4.08 and $4.66 for options granted during the year ended December 31, 2013 and December 31, 2012, respectively.

The following summary reflects the stock option activity and related information for the year ended December 31, 2014:

	Options	Weighted Average Exercise Price
Outstanding at January 1, 2014	963,196	$12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	—	—
Outstanding at December 31, 2014	963,196	$12.74
Exercisable at December 31, 2014	602,880	$12.74

A summary of our unvested stock options and the changes during the year ended December 31, 2014 is presented below:

	Outstanding	Weighted Average Grant-Date Fair Value
Unvested as of January 1, 2014	620,412	$4.42
Granted	—	—
Vested	(260,096)	4.55
Forfeited/expired	—	—
Unvested as of December 31, 2014	360,316	$4.32

The number of options exercisable at December 31, 2014 was 602,880 with a weighted average remaining contractual life of 7.3 years and a weighted-average exercise price of $12.74 per share.

As of December 31, 2014, the unrecognized compensation cost related to outstanding stock options was $0.7 million. This cost is expected to be recognized over a weighted-average period of 0.8 years. The fair value of options that vested during the year ended December 31, 2014, December 31, 2013 and December 31, 2012 was $1.2 million, $0.9 million and $0.8 million, respectively.

Restricted Stock

Restricted stock awards consist of grants of our common stock that vest ratably over three to four years. We recognize compensation expense on a straight-line basis over the vesting period. The fair value of restricted stock awards is determined based on the estimated fair market value of our shares on the grant date. As of December 31, 2014, there was $7.5 million of total unrecognized compensation cost related to unvested restricted stock awards. That cost is expected to be recognized over a weighted-average period of 1.3 years.

A summary of the status of our restricted stock awards and of changes in restricted stock outstanding for the year ended December 31, 2014 is as follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Outstanding at January 1, 2014	147,451	$12.48
Granted	749,720	10.80
Vested	(118,406)	12.54
Forfeited/expired	—	—
Outstanding at December 31, 2014	778,765	$10.85

Restricted Stock Units

We have granted restricted stock units (RSUs) to key employees under the 2012 Plan. We have granted performance-based and market-based RSUs, 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. Vesting of the market-based RSUs is based on our three year total shareholder return (TSR) as measured against a three year TSR of a defined peer group and vesting of the performance-based RSUs is based on our cumulative EBITDA (CEBITDA), 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 RSUs. The fair value of the CEBITDA performance-based RSUs is based on the market price of our common stock on the date of grant. During the restriction period, the RSUs may not be transferred or encumbered, and the recipient does not receive dividend equivalents or have voting rights until the units vest. As of December 31, 2014, there was $4.4 million of total unrecognized compensation cost related to unvested RSUs. This cost is expected to be recognized over a weighted-average period of 1.4 years.

The assumptions used to value our TSR market-based RSUs granted during the year ended December 31, 2014 were a a risk-free interest rate of 0.08%, an expected volatility of 44.1% and an expected dividend yield of 0.0%. Based on the Monte Carlo simulation, these 171,577 RSUs were valued at $16.74.

A summary of the status of our RSUs as of December 31, 2014, and of changes in RSUs outstanding during the year ended December 31, 2014, is as follows:

	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2014	—	$—
Granted	343,150	13.72
Vested and converted	—	—
Forfeited/expired	—	—
Outstanding at December 31, 2014	343,150	$13.72

10. Stockholders' Equity and Loss per Share

As of December 31, 2014, we had a total of 24,629,333 shares of common stock, $0.01 par value, issued and outstanding including 778,765 shares of restricted stock. We also had 85,011 shares held as treasury stock. Total authorized common stock is 100,000,000 shares.

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,		
	2014	2013	2012
	(in thousands, except for per share data)		
Net loss (numerator)	$(28,168)	$(1,997)	$(4,948)
Loss per share:			
Basic	$(1.65)	$(0.16)	$(0.49)
Diluted	$(1.65)	$(0.16)	$(0.49)
Shares (denominator):			
Weighted-average number of shares outstanding-basic	17,078	12,179	10,141
Weighted-average common shares outstanding-diluted	17,078	12,179	10,141

The year ended December 31, 2014 per share calculations above exclude 963,196 stock options, 343,154 restricted stock units and 2.2 million warrants because they were anti-dilutive. The year ended December 31, 2013 per share calculations above exclude 963,196 stock options and 2.2 million warrants because they were anti-dilutive. The year ended December 31, 2012 per share calculations above exclude 888,228 stock options and 2.2 million warrants because they were anti-dilutive.

11. 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.

12. Commitments and Contingencies

Purchase Commitments

As of December 31, 2014, we had outstanding purchase commitments to a number of suppliers totaling $90.1 million related primarily to the construction of drilling rigs.

Lease Commitments

We lease certain buildings, equipment and vehicles under non-cancelable operating leases. The minimum rental commitments under non-cancelable operating leases, with lease terms in excess of one year subsequent to December 31, 2014, were as follows:

(in thousands)	
2015	$739
2016	427
2017	229
2018	49
2019	50
Thereafter	—
	$1,494

Contingencies

Our operations inherently expose us to various liabilities and exposures that could result in third party lawsuits, claims and other causes of action. We are party to lawsuits, in the ordinary course of business, the outcome of which is not expected to have, either individually or in the aggregate, a material impact on our financial position, results of operations or cash flows.

13. 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 gas prices. We have a number of customers that account for 10% or more of our revenues. For 2014, these customers include Laredo Petroleum, Inc. (22%), Apache Corporation (21%), COG Operating, LLC, a subsidiary of Concho Resources, Inc. (21%) and BOPCO, L.P. (20%). For 2013, these customers include Apache Corporation (30%), BOPCO, LP (16%), Newfield Exploration Company (11%), W&T Offshore, Inc. (10%) and Anadarko Petroleum Corporation (10%). For 2012, these customers include Eagle Rock Mid-Continent Operating, LLC (30%) and GLB Exploration, Inc. (27%). As of December 31, 2014, Apache Corporation (22%), COG Operating, LLC, a subsidiary of Concho Resources, Inc. (20%), BOPCO, L.P. (18%), Laredo Petroleum, Inc. (16%) and Pioneer Natural Resources USA, Inc. (11%) accounted for 10% or more of our accounts receivable. As of December 31, 2013, Apache Corporation (27%), Laredo Petroleum, Inc. (22%), BOPCO, LP (17%) and Rosetta Resources Operating L.P. (10%) accounted for 10% or more of our accounts receivable. As of December 31, 2012, Eagle Rock Mid-Continent Operating, LLC (35%), GLB Exploration, Inc. (30%) and Sheridan Production Company (11%) accounted for 10% or more of our accounts receivable. 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 ICD. Our results of operations, cash flows and financial condition may be affected by these factors. Additionally, these factors could impact our ability to obtain additional debt and equity capital required to implement the our rig construction and growth strategy, and the cost of that capital.

We have concentrated credit risk for cash by maintaining deposits in a major bank, 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 bank and have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk. As of December 31, 2014, we had approximately $10.4 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.

14. Related Parties and Other Matters

During 2011, we entered into the Contribution Agreement with GES and RigAssetCo. Two of our directors as of December 31, 2014, also were directors of the parent company of GES.

During the year ended December 31, 2012, we purchased inventory from GES for a total purchase price $0.8 million.

In connection with the Contribution Agreement, we also entered into an agreement with GES pursuant to which the we and GES provided various services to each other on a transitional basis in order to ensure an orderly transition of the operations acquired in the Contribution Transaction (the “Transition Services Agreement”). These transitional services included (i) ICD providing accounting and information technology support to GES, (ii) ICD completing certain warranty work and other services work relating to contracts not assumed in the Contribution Transaction, (iii) the lease of certain real estate by GES from ICD and (iv) GES providing various services and payroll assistance for ICD. We did not provide any of these services to GES during 2013 or 2014, but for the year ended December 31, 2012, we recorded $1.5 million in revenues related to the Transition Services Agreement. All amounts owed to us by GES pursuant to the Transition Services Agreement have been paid.

One of the our directors is also a director of one of our customers. We recorded $1.4 million and $0.9 million in revenues with this customer for the year ended December 31, 2014 and 2013, respectively. There were no outstanding trade receivables with this customer as of December 31, 2014 and totaled $0.9 million as of December 31, 2013. The outstanding trade receivable is included in accounts receivable, net in our accompanying balance sheet. We did not transact any business with this customer for the year ended December 31, 2012.

15. Unaudited Quarterly Financial Data

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

	Year Ended December 31, 2014			
	Quarter Ended			
	March 31	June 30	September 30	December 31
Revenue	$13,549	$14,661	$19,123	$23,014
Operating income (loss)	(5,199)	1,444	(672)	(28,640)
Net income (loss)	(3,705)	1,556	(1,413)	(24,606)
Loss per share:				
Basic	$(0.30)	$0.13	$(0.07)	$(1.00)
Diluted	$(0.30)	$0.13	$(0.07)	$(1.00)

	Year Ended December 31, 2013			
	Quarter Ended			
	March 31	June 30	September 30	December 31
Revenue	$8,257	$9,784	$11,604	$13,141
Operating loss	(1,862)	(1,359)	(241)	(1,195)
Net income (loss)	(1,696)	(669)	576	(208)
Loss per share:				
Basic	$(0.14)	$(0.05)	$0.05	$(0.02)
Diluted	$(0.14)	$(0.05)	$0.05	$(0.02)

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Comprehensive Income	$782	904	191	(1,062)	815

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Balance Sheet	Millions of Dollars June 30, 2017 Phillips 66	Phillips 66 Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets					
Cash and cash equivalents	$—	541	1,620	—	2,161
Accounts and notes receivable	10	3,997	3,543	(1,956)	5,594
Inventories	—	2,855	1,390	—	4,245
Prepaid expenses and other current assets	1	318	137	—	456
Total Current Assets	11	7,711	6,690	(1,956)	12,456
Investments and long-term receivables	30,151	22,151	8,991	(47,786)	13,507
Net properties, plants and equipment	—	13,077	8,216	—	21,293
Goodwill	—	2,853	417	—	3,270
Intangibles	—	726	163	—	889
Other assets	14	241	161	(3)	413
Total Assets	$30,176	46,759	24,638	(49,745)	51,828
Liabilities and Equity					
Accounts payable	$—	5,638	2,873	(1,956)	6,555
Short-term debt	449	13	31	—	493
Accrued income and other taxes	—	397	496	—	893
Employee benefit obligations	—	315	44	—	359
Other accruals	54	341	179	—	574
Total Current Liabilities	503	6,704	3,623	(1,956)	8,874
Long-term debt	6,969	52	2,451	—	9,472
Asset retirement obligations and accrued environmental costs	—	461	164	—	625
Deferred income taxes	—	4,958	2,610	(3)	7,565
Employee benefit obligations	—	971	279	—	1,250
Other liabilities and deferred credits	307	3,854	3,989	(7,914)	236
Total Liabilities	7,779	17,000	13,116	(9,873)	28,022
Common stock	10,176	25,403	10,438	(35,841)	10,176
Retained earnings	13,030	5,165	(1)	(5,193)	13,001
Accumulated other comprehensive loss	(809)	(809)	(353)	1,162	(809)
Noncontrolling interests	—	—	1,438	—	1,438
Total Liabilities and Equity	$30,176	46,759	24,638	(49,745)	51,828

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Balance Sheet	Millions of Dollars December 31, 2016 Phillips 66	Phillips 66 Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets					
Cash and cash equivalents	$—	854	1,857	—	2,711
Accounts and notes receivable	13	4,336	3,276	(1,228)	6,397
Inventories	—	2,198	952	—	3,150
Prepaid expenses and other current assets	2	317	103	—	422
Total Current Assets	15	7,705	6,188	(1,228)	12,680
Investments and long-term receivables	31,165	22,733	8,588	(48,952)	13,534
Net properties, plants and equipment	—	13,044	7,811	—	20,855
Goodwill	—	2,853	417	—	3,270
Intangibles	—	719	169	—	888
Other assets	15	245	168	(2)	426
Total Assets	$31,195	47,299	23,341	(50,182)	51,653
Liabilities and Equity					
Accounts payable	$—	5,626	2,663	(1,228)	7,061
Short-term debt	500	30	20	—	550
Accrued income and other taxes	—	348	457	—	805
Employee benefit obligations	—	475	52	—	527
Other accruals	59	371	90	—	520
Total Current Liabilities	559	6,850	3,282	(1,228)	9,463
Long-term debt	6,920	150	2,518	—	9,588
Asset retirement obligations and accrued environmental costs	—	501	154	—	655
Deferred income taxes	—	4,391	2,354	(2)	6,743
Employee benefit obligations	—	948	268	—	1,216
Other liabilities and deferred credits	1,297	3,337	4,060	(8,431)	263
Total Liabilities	8,776	16,177	12,636	(9,661)	27,928
Common stock	10,777	25,403	10,117	(35,520)	10,777
Retained earnings	12,637	6,714	(269)	(6,474)	12,608
Accumulated other comprehensive loss	(995)	(995)	(478)	1,473	(995)
Noncontrolling interests	—	—	1,335	—	1,335
Total Liabilities and Equity	$31,195	47,299	23,341	(50,182)	51,653

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Statement of Cash Flows	Millions of Dollars Six Months Ended June 30, 2017 Phillips 66	Phillips 66 Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities					
Net Cash Provided by Operating Activities	$1,143	701	1,104	(1,632)	1,316
Cash Flows From Investing Activities					
Capital expenditures and investments*	—	(675)	(393)	140	(928)
Proceeds from asset dispositions**	—	2	49	—	51
Intercompany lending activities	256	855	(1,111)	—	—
Collection of advances/loans—related parties	—	75	250	—	325
Restricted cash received from consolidation of business	—	—	318	—	318
Other	—	(59)	(2)	—	(61)
Net Cash Provided by (Used in) Investing Activities	256	198	(889)	140	(295)
Cash Flows From Financing Activities					
Issuance of debt	1,500	—	1,103	—	2,603
Repayment of debt	(1,500)	(10)	(1,400)	—	(2,910)
Issuance of common stock	6	—	—	—	6
Repurchase of common stock	(666)	—	—	—	(666)
Dividends paid on common stock	(686)	(1,202)	(430)	1,632	(686)
Distributions to noncontrolling interests	—	—	(54)	—	(54)
Net proceeds from issuance of Phillips 66 Partners LP common units	—	—	171	—	171
Other*	(53)	—	139	(140)	(54)
Net Cash Used in Financing Activities	(1,399)	(1,212)	(471)	1,492	(1,590)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	—	—	19	—	19
Net Change in Cash, Cash Equivalents and Restricted Cash	—	(313)	(237)	—	(550)
Cash, cash equivalents and restricted cash at beginning of period	—	854	1,857	—	2,711
Cash, Cash Equivalents and Restricted Cash at End of Period	$—	541	1,620	—	2,161

* Includes intercompany capital contributions.
** Includes return of investments in equity affiliates.

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Statement of Cash Flows	Millions of Dollars Six Months Ended June 30, 2016 Phillips 66	Phillips 66 Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities					
Net Cash Provided by Operating Activities	$ 2,486	1,259	876	(3,208)	1,413
Cash Flows From Investing Activities					
Capital expenditures and investments*	—	(685)	(723)	38	(1,370)
Proceeds from asset dispositions**	—	3	12	—	15
Intercompany lending activities	(1,190)	2,295	(1,105)	—	—
Advances/loans—related parties	—	(75)	(107)	—	(182)
Other	—	13	(88)	—	(75)
Net Cash Provided by (Used in) Investing Activities	(1,190)	1,551	(2,011)	38	(1,612)
Cash Flows From Financing Activities					
Issuance of debt	—	—	150	—	150
Repayment of debt	—	(11)	(155)	—	(166)
Issuance of common stock	9	—	—	—	9
Repurchase of common stock	(633)	—	—	—	(633)
Dividends paid on common stock	(625)	(2,528)	(680)	3,208	(625)
Distributions to noncontrolling interests	—	—	(28)	—	(28)
Net proceeds from issuance of Phillips 66 Partners LP common units	—	—	669	—	669
Other*	(47)	18	40	(38)	(27)
Net Cash Used in Financing Activities	(1,296)	(2,521)	(4)	3,170	(651)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	—	—	8	—	8
Net Change in Cash, Cash Equivalents and Restricted Cash	—	289	(1,131)	—	(842)
Cash, cash equivalents and restricted cash at beginning of period	—	575	2,499	—	3,074
Cash, Cash Equivalents and Restricted Cash at End of Period	$ —	864	1,368	—	2,232

* Includes intercompany capital contributions.
** Includes return of investments in equity affiliates.

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Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Unless otherwise indicated, "the company," "we," "our," "us" and "Phillips 66" are used in this report to refer to the businesses of Phillips 66 and its consolidated subsidiaries. Unless the context requires otherwise, references to "DCP Midstream" include the consolidated operations of DCP Midstream, LLC, including DCP Midstream, LP (formerly named DCP Midstream Partners, LP), the master limited partnership formed by DCP Midstream, LLC.

Management's Discussion and Analysis is the company's analysis of its financial performance, its financial condition, and significant trends that may affect future performance. It should be read in conjunction with the consolidated financial statements and notes included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "sho "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identif forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995."

The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to net income (loss) attributable to Phillips 66.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

Phillips 66 is an energy manufacturing and logistics company with midstream, chemicals, refining, and marketing and specialties businesses. At June 30, 2017, we had total assets of $52 billion. Our common stock trades on the New York Stock Exchange under the symbol PSX.

Executive Overview

We reported earnings of $550 million in the second quarter of 2017 and cash provided by operating activities of $1,865 million. In addition, Phillips 66 Partners raised net proceeds of $131 million from its continuous offering program of common units. We used available cash to fund capital expenditures and investments of $458 million, pay dividends of $360 million, repurchase $381 million of our common stock and reduce debt by $245 million. We ended the second quarter of 2017 with $2.2 billion of cash and cash equivalents and approximately $5.6 billion of total capacity available under our liquidity facilities.

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Business Environment

Commodity prices, particularly West Texas Intermediate (WTI), trended lower during the second quarter of 2017, with the U.S. crude oil benchmark, WTI, declining from an average of $51.83 per barrel in the first quarter to $48.24 per barrel in the second quarter. The WTI discount to the international benchmark, Brent, narrowed from the first quarter average of $1.95 per barrel to $1.59 per barrel in the second quarter. The sustained low-commodity-price environment had a variety of impacts, both favorable and unfavorable, on our businesses that vary by segment.

Earnings in the Midstream segment, which includes our 50 percent equity investment in DCP Midstream, LLC (DCP Midstream), are closely linked to natural gas liquids (NGL) prices, natural gas prices and crude oil prices. The fall in crude prices contributed to weakening NGL prices in the second quarter of 2017 compared with the first quarter of 2017. Higher NGL prices in the second quarter of 2017 compared with the second quarter of 2016 were due to the strengthening of the propane and butane markets as a result of lower inventories and higher exports. Average natural gas prices remained consistent compared with the first quarter of 2017, and improved compared with the second quarter of 2016, benefiting from lower inventory and supply.

The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem). The chemicals and plastics industry is mainly a commodity-based industry where the margins for key products are based on supply and demand, as well as cost factors. The petrochemicals industry continues to experience lower ethylene cash costs in regions of the world where ethylene manufacturing is based upon NGL rather than crude-oil-derived feedstocks. In particular, companies with North American light NGL-based crackers have benefited from lower-priced feedstocks. The ethylene-to-polyethylene chain margins in the second quarter of 2017 improved moderately compared with the first quarter of 2017 and the second quarter of 2016 due to higher polyethylene prices.

The results of our Refining segment are driven by several factors including refining margins, cost control, refinery throughput, feedstock costs, product yields and turnaround activity. Industry crack spread indicators, the difference between market prices for refined products and crude oil, are used to estimate refining margins. The U.S. Gulf Coast 3:2:1 crack spread (three barrels of crude oil producing two barrels of gasoline and one barrel of diesel) increased seasonally in the second quarter of 2017 compared with the first quarter of 2017 and rose slightly when compared with the second quarter of 2016.

Results for our Marketing and Specialties (M&S) segment depend largely on marketing fuel margins, lubricant margins, and other specialty product margins. While M&S margins are primarily driven by market factors, largely determined by the relationship between supply and demand, marketing fuel margins, in particular, are influenced by the trend in spot prices for refined products. Generally speaking, a downward trend of spot prices has a favorable impact on marketing fuel margins, while an upward trend of spot prices has an unfavorable impact on marketing fuel margins.

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RESULTS OF OPERATIONS

Unless otherwise indicated, discussion of results for the three- and six-month periods ended June 30, 2017, is based on a comparison with the corresponding periods of 2016.

Consolidated Results
A summary of net income (loss) attributable to Phillips 66 by business segment follows:

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Midstream	$59	39	136	104
Chemicals	196	190	377	346
Refining	224	149	483	235
Marketing and Specialties	214	229	355	434
Corporate and Other	(143)	(111)	(266)	(238)
Net income attributable to Phillips 66	$550	496	1,085	881

Earnings for Phillips 66 increased $54 million, or 11 percent, in the second quarter of 2017, mainly reflecting:

- Higher realized refining margins.
- Improved equity earnings from DCP Midstream.

These increases were partially offset by:

- Higher refining turnaround costs.
- Higher interest and debt expense.
- Lower U.S. realized marketing margins.

Earnings for Phillips 66 increased $204 million, or 23 percent, in the six-month period of 2017, mainly reflecting:

- Recognition of a $261 million after-tax gain from the consolidation of Merey Sweeny, L.P. (MSLP).
- Higher realized refining margins.
- Improved equity earnings from DCP Midstream.

These increases were partially offset by:

- Higher refining turnaround costs.
- Lower realized U.S. marketing margins.
- Higher interest and debt expense.

See the “Segment Results” section for additional information on our segment results.

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Statement of Income Analysis

Sales and other operating revenues for the second quarter and six-month period of 2017 increased 10 percent and 20 percent, respectively, and purchased crude oil and products increased 13 percent and 28 percent, respectively. These increases were mainly due to higher prices for petroleum products, crude oil and NGL.

Other income increased $435 million in the six-month period of 2017. We recognized a noncash, pre-tax gain of $423 million in the first quarter of 2017 related to the consolidation of MSLP. See Note 5—Business Combinations, in the Notes to Consolidated Financial Statements, for additional information.

Operating expenses increased 14 percent in the second quarter of 2017 and increased 19 percent in the six-month period of 2017. The increases for both periods were mainly due to higher refining turnaround costs, transportation costs and costs related to our employee benefit plans. See Note 15—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for more information.

Depreciation and amortization increased 10 percent in the second quarter of 2017 and increased 11 percent in the six-month period of 2017, reflecting the impact of operations at the Freeport LPG Export Terminal and an increase in properties, plants and equipment.

Taxes other than income taxes decreased 7 percent in the second quarter of 2017 and decreased 8 percent in the six-month period of 2017. These decreases were mainly attributable to lower excise taxes from our U.K. operations as a result of the sale of the Whitegate Refinery and related marketing assets in September 2016.

Interest and debt expense increased 29 percent in the second quarter of 2017 and increased 25 percent in the six-month period of 2017. The increases were mainly due to higher average debt principal balances and lower capitalized interest due to the Freeport LPG Export Terminal beginning operations in the fourth quarter of 2016. These increases were partially offset by lower interest rates on debt issued in April 2017 to repay $1,500 million of 2.95% Senior Notes that came due in the second quarter of 2017.

Net income attributable to noncontrolling interest increased $11 million in the second quarter of 2017 and increased $26 million in the six-month period of 2017, reflecting the contribution of assets to Phillips 66 Partners during 2016.

See Note 20—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our provision for income taxes and effective tax rates.

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Segment Results

Midstream

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
	Millions of Dollars			
Net Income (Loss) Attributable to Phillips 66				
Transportation	$51	65	107	137
NGL	(5)	(17)	(1)	(28)
DCP Midstream	13	(9)	30	(5)
Total Midstream	$59	39	136	104

	Thousands of Barrels Daily			
Transportation Volumes				
Pipelines*	3,430	3,638	3,449	3,563
Terminals	2,581	2,442	2,489	2,325
Operating Statistics				
NGL fractionated**	177	174	176	168
NGL extracted***	367	416	354	399

* Pipelines represent the sum of volumes transported through each separately tariffed pipeline segment, including our share of equity volumes from Yellowstone Pipe Line Company and Lake Charles Pipe Line Company.
** Excludes DCP Midstream.
*** Includes 100 percent of DCP Midstream’s volumes.

	Dollars Per Gallon			
Weighted Average NGL Price*				
DCP Midstream	$0.55	0.46	0.57	0.41

* Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by NGL component and location mix.

The Midstream segment gathers, processes, transports and markets natural gas; and transports, stores, fractionates and markets NGL in the United States. In addition, this segment transports crude oil and other feedstocks to our refineries and other locations, delivers refined and specialty products to market, and provides terminaling and storage services for crude oil and petroleum products. The segment also stores, refrigerates, and exports liquefied petroleum gas primarily to Asia and Europe. The Midstream segment includes our master limited partnership, Phillips 66 Partners LP, as well as our 50 percent equity investment in DCP Midstream.

Earnings from the Midstream segment increased $20 million in the second quarter of 2017, and increased $32 million in the six-month period of 2017.

Transportation earnings decreased $14 million in the second quarter of 2017 and $30 million in the six-month period of 2017. The decreases were mainly due to higher operating costs, primarily related to integrity and maintenance activities, and higher income attributable to noncontrolling interests, reflecting the contribution of assets to Phillips 66

Partners. These decreases were partially offset by improved volumes and earnings from equity affiliates in both the three- and six-month periods of 2017.

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Results from our NGL business improved $12 million in the second quarter of 2017 and $27 million in the six-month period of 2017. Both periods benefited from higher realized margins, which include results from the Freeport LPG Export Terminal. The increases were partially offset by higher depreciation expense and operating costs, primarily related to the Freeport LPG Export Terminal, in both the three- and six-month periods of 2017.

Earnings from our investment in DCP Midstream increased $22 million in the second quarter of 2017. The increase was mainly driven by improved hedging results and higher commodity prices, partially offset by lower volumes. Earnings from our investment in DCP Midstream increased $35 million in the six-month period of 2017. The increase was mainly driven by improved hedging results and higher commodity prices. The increase was partially offset by a favorable legal settlement recognized in 2016 and lower volumes in the six-month period of 2017. In addition, the increases in both periods in 2017 reflect the gain recognized from the sale of a non-core gathering system in the second quarter of 2017.

Effective January 1, 2017, DCP Midstream, LLC and its master limited partnership (then named DCP Midstream Partners, LP, subsequently renamed DCP Midstream, LP on January 11, 2017, and referred to herein as DCP Partners) closed a transaction in which DCP Midstream, LLC contributed subsidiaries owning all of its operating assets and its existing debt to DCP Partners, in exchange for approximately 31.1 million DCP Partners units. Following the transaction, we and our co-venturer retained our 50/50 investment in DCP Midstream, LLC and DCP Midstream, LLC retained its incentive distribution rights in DCP Partners, through its ownership of the general partner of DCP Partners, and held a 38 percent interest in DCP Partners. See the “Equity Affiliates” section of “Significant Sources of Capital” in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information on this transaction.

See the “Business Environment and Executive Overview” section for information on market factors impacting this quarter’s results.

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Chemicals

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
	Millions of Dollars			
Net Income Attributable to Phillips 66	$ 196	190	377	346
	Millions of Pounds			
CPChem Externally Marketed Sales Volumes*				
Olefins and Polyolefins (O&P)	4,137	4,139	8,153	8,141
Specialties, Aromatics and Styrenics (SA&S)	1,175	1,212	2,381	2,466
	5,312	5,351	10,534	10,607

* Includes 100 percent of CPChem's outside sales of produced petrochemical products, as well as commission sales from equity affiliates.

Olefins and Polyolefins Capacity Utilization (percent)*	98 %	92	93	93

* Revised to exclude polyethylene pipe operations. Prior periods recast for comparability.

The Chemicals segment consists of our 50 percent interest in CPChem, which we account for under the equity method. CPChem uses NGL and other feedstocks to produce petrochemicals. These products are then marketed and sold or used as feedstocks to produce plastics and other chemicals. We structure our reporting of CPChem's operations around two primary business lines: Olefins and Polyolefins (O&P) and Specialties, Aromatics and Styrenics (SA&S).

Earnings from the Chemicals segment increased $6 million in the second quarter of 2017. The increase was mainly driven by higher O&P volumes, lower O&P controllable costs, and improved polyethylene and benzene margins. These increases were partially offset by lower equity earnings from CPChem's equity affiliates.

Earnings from the Chemicals segment increased $31 million in the six-month period of 2017. The increase was mainly driven by higher O&P volumes and benzene margins. In addition, CPChem recognized a gain from the sale of its K-Resin® SBC business in the first quarter of 2017. These increases were partially offset by lower equity earnings from CPChem's O&P equity affiliates, as well as lower SA&S equity earnings due to an impairment recognized by CPChem.

See the "Business Environment and Executive Overview" section for information on market factors impacting this quarter's results.

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Refining

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
	Millions of Dollars			
Net Income (Loss) Attributable to Phillips 66				
Atlantic Basin/Europe	$107	32	57	36
Gulf Coast	53	5	381	73
Central Corridor	27	55	89	75
West Coast	37	57	(44)	51
Worldwide	$224	149	483	235
	Dollars Per Barrel			
Refining Margins*				
Atlantic Basin/Europe	$7.90	6.15	7.20	5.97
Gulf Coast	6.74	5.18	7.36	5.94
Central Corridor	9.96	8.65	10.25	8.05
West Coast	10.83	10.94	10.44	10.34
Worldwide	8.44	7.13	8.49	7.12

* Based on total processed inputs and includes proportional share of refining margins contributed by certain equity affiliates.

	Thousands of Barrels Daily			
Operating Statistics				
Refining operations*				
Atlantic Basin/Europe				
Crude oil capacity	520	588	520	588
Crude oil processed	533	594	450	585
Capacity utilization (percent)	103%	101	87	100
Refinery production	575	629	516	620
Gulf Coast				
Crude oil capacity	743	743	743	743
Crude oil processed	715	738	691	709
Capacity utilization (percent)	96%	99	93	95
Refinery production	801	817	775	786
Central Corridor				
Crude oil capacity	493	493	493	493
Crude oil processed	465	500	468	486
Capacity utilization (percent)	94%	101	95	99
Refinery production	485	520	489	507
West Coast				
Crude oil capacity	360	360	360	360
Crude oil processed	366	348	323	336
Capacity utilization (percent)	102%	97	90	93
Refinery production	388	371	347	360
Worldwide				
Crude oil capacity	2,116	2,184	2,116	2,184
Crude oil processed	2,079	2,180	1,932	2,116

Capacity utilization (percent)	98 %	100	91	97
Refinery production	2,249	2,337	2,127	2,273

* Includes our share of equity affiliates.

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The Refining segment buys, sells and refines crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels) at 13 refineries, mainly in the United States and Europe.

Earnings for the Refining segment increased $75 million in the second quarter of 2017. The increase was primarily due to higher refining realized margins, resulting from improved clean product differentials, secondary product margins and improved distillate crack spreads, partially offset by lower feedstock advantage. These impacts were further offset by higher controllable costs as a result of increased turnaround activities.

Earnings for the Refining segment increased $248 million in the six-month period of 2017. The increase in earnings was mainly due to a gain recognized from the consolidation of MSLP, which owns a delayed coker and related facilities at the Sweeny Refinery. Earnings were also impacted by higher realized refining margins, which were more than offset by increased turnaround costs. See Note 5—Business Combinations, in the Notes to Consolidated Financial Statements, for additional information.

See the “Business Environment and Executive Overview” section for information on market factors impacting this quarter’s results.

Our worldwide refining crude oil capacity utilization rate was 98 percent and 91 percent in the second quarter and six-month period of 2017, respectively, compared with 100 percent and 97 percent in the second quarter and six-month period of 2016, respectively. These decreases were primarily attributable to higher turnaround activities in 2017 as compared with 2016.

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Marketing and Specialties

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
	Millions of Dollars			
Net Income Attributable to Phillips 66				
Marketing and Other	$181	199	305	361
Specialties	33	30	50	73
Total Marketing and Specialties	$214	229	355	434

	Dollars Per Barrel			
Realized Marketing Fuel Margin*				
U.S.	$1.74	1.79	1.61	1.81
International	4.95	4.16	4.33	3.66

* On third-party petroleum products sales.

	Dollars Per Gallon			
U.S. Average Wholesale Prices*				
Gasoline	$1.85	1.73	1.83	1.55
Distillates	1.71	1.51	1.73	1.34

* Excludes excise taxes.

	Thousands of Barrels Daily			
Marketing Petroleum Products Sales Volumes				
Gasoline	1,275	1,261	1,215	1,219
Distillates	912	975	874	939
Other products	18	19	16	16
Total	2,205	2,255	2,105	2,174

The M&S segment purchases for resale and markets refined petroleum products (such as gasoline, distillates and aviation fuels), mainly in the United States and Europe. In addition, this segment includes the manufacturing and marketing of specialty products (such as base oils and lubricants), as well as power generation operations.

The M&S segment earnings decreased $15 million in the second quarter of 2017 and $79 million in the six-month period of 2017. The decreases were primarily due to lower U.S. realized marketing margins. In addition, the six-month period results reflected increased turnaround activities and unplanned outages at Excel Paralubes.

See the “Business Environment and Executive Overview” section for information on marketing fuel margins and other market factors impacting this quarter’s results.

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Corporate and Other

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Net Loss Attributable to Phillips 66				
Net interest	$(65)	(52)	(130)	(106)
Corporate general and administrative expenses	(47)	(40)	(86)	(82)
Technology	(14)	(14)	(29)	(28)
Other	(17)	(5)	(21)	(22)
Total Corporate and Other	$(143)	(111)	(266)	(238)

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest increased in the second quarter and for the six-month period of 2017, mainly due to lower capitalized interest and higher interest expense driven by higher average debt principal balances as a result of Phillips 66 Partners' debt issuance in October 2016.

The category "Other" includes certain income tax expenses, environmental costs associated with sites no longer in operation, foreign currency transaction gains and losses and other costs not directly associated with an operating segment. The increase in costs during the second quarter of 2017 reflected higher tax expense.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated	
	June 30 2017	December 31 2016
Cash and cash equivalents	$2,161	2,711
Short-term debt	493	550
Total debt	9,965	10,138
Total equity	23,806	23,725
Percent of total debt to capital*	30 %	30
Percent of floating-rate debt to total debt	17 %	3

* Capital includes total debt and total equity.

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources but rely primarily on cash generated from operating activities. Additionally, Phillips 66 Partners raises funds for its growth activities through debt and equity offerings. During the first six months of 2017, we generated $1,316 million in cash from operations. In addition, Phillips 66 Partners raised net proceeds of $171 million from its continuous offering program of common units, and we collected $325 million of previously issued related-party loans. Available cash was primarily used for capital expenditures and investments ($928 million), repurchases of our common stock ($666 million) and dividend payments on our common stock ($686 million). During the first six months of 2017, cash and cash equivalents decreased by $550 million to $2,161 million.

In addition to cash flows from operating activities, we rely on our commercial paper and credit facility programs, asset sales and our ability to issue securities using our shelf registration statement to support our short- and long-term liquidity requirements. We believe current cash and cash equivalents and cash generated by operations, together with access to external sources of funds as described below under “Significant Sources of Capital,” will be sufficient to meet our funding requirements in the near and long term, including our capital spending, dividend payments, benefit plan contributions, debt repayment and share repurchases.

Significant Sources of Capital

Operating Activities

During the first six months of 2017, cash generated by operating activities was $1,316 million, compared with $1,413 million for the first six months of 2016. The decrease in the first six months of 2017, compared with the same period in 2016, primarily reflects the impact of higher inventory builds, which were partially offset by increased distributions from our equity affiliates.

Our short- and long-term operating cash flows are highly dependent upon refining and marketing margins, NGL prices, and chemicals margins. Prices and margins in our industry are typically volatile, and are driven by market conditions over which we have little or no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level and quality of output from our refineries also impacts our cash flows. Factors such as operating efficiency, maintenance turnarounds, market conditions, feedstock availability and weather conditions can affect output. We actively manage the operations of our refineries, and any variability in their operations typically has not been as significant to cash flows as that caused by margins and prices.

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Equity Affiliates
Our operating cash flows are also impacted by distribution decisions made by our equity affiliates, including DCP Midstream, CPChem and WRB. During the first six months of 2017, cash from operations included distributions of $575 million from our equity affiliates, compared with $253 million during the same period of 2016. In the second quarter of 2017, DCP Midstream resumed distributions. We cannot control the amount of future dividends from equity affiliates; therefore, future dividend payments by these companies are not assured.

Effective January 1, 2017, DCP Midstream, LLC and DCP Partners closed a transaction in which DCP Midstream, LLC contributed subsidiaries owning all of its operating assets, $424 million of cash and $3.15 billion of debt to DCP Partners, in exchange for DCP Partners units which had an estimated fair value of $1.125 billion at the time of the transaction. We and our co-venturer retained our 50/50 investment in DCP Midstream, LLC, and DCP Midstream, LLC retained its incentive distribution rights in DCP Partners through its ownership of the general partner of DCP Partners. After the transaction, DCP Midstream, LLC held a 38 percent interest in DCP Partners. DCP Midstream, LLC, through its ownership of the general partner, has agreed, if required, to forgo receipt of incentive distribution rights up to $100 million annually (100 percent basis) through 2019, to support a minimum distribution coverage ratio for DCP Partners. In connection with the transaction, DCP Midstream, LLC terminated its revolving credit agreement, which had previously served to limit distributions to its owners while amounts had been borrowed under the facility. As a result, distributions to the owners of DCP Midstream, LLC resumed in 2017.

Foreign Cash Holdings
At June 30, 2017, approximately 26 percent of our consolidated cash and cash equivalents balance was available for domestic use without incurring material U.S. income taxes in excess of the amounts already accrued in the financial statements. We believe the remaining amount, primarily attributable to cash held in foreign locations where we have asserted our intention to indefinitely reinvest earnings, does not materially affect our consolidated liquidity due to the following factors:

- A substantial portion of our foreign cash supports the liquidity needs and regulatory requirements of our foreign operations.
- We have the ability to fund a significant portion of our domestic capital requirements with cash provided by domestic operating activities.
- We have access to U.S. capital markets through our $5 billion committed revolving credit facility, commercial paper program, and universal shelf registration statement.

Phillips 66 Partners LP
In 2016, Phillips 66 Partners began issuing common units under a continuous offering program, which allows for the issuance of up to an aggregate of $250 million of Phillips 66 Partners’ common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of the offerings. We refer to this as an at-the-market, or ATM, program. For the six months ended June 30, 2017, on a settlement-date basis, Phillips 66 Partners issued 3,323,576 common units under the ATM program, which generated net proceeds of $171 million. From inception through June 30, 2017, Phillips 66 Partners has issued an aggregate of 3,669,728 common units under the ATM program, generating net proceeds of $190 million.

Credit Facilities and Commercial Paper
As of June 30, 2017, no amount had been drawn under our $5 billion credit facility; however, $51 million in letters of credit had been issued that were supported by this facility. As of June 30, 2017, there was $50 million outstanding under the $750 million revolving credit agreement of Phillips 66 Partners.

We have a $5 billion commercial paper program, supported by our credit facility, for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. As of June 30, 2017, we had no outstanding commercial paper.

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Debt Issuances

On April 21, 2017, Phillips 66 completed a private offering of $600 million aggregate principal amount of unsecured notes consisting of:

- $300 million of floating rate Notes due 2019.
- $300 million of floating rate Notes due 2020.

The notes are guaranteed by Phillips 66 Company, a wholly owned subsidiary. Phillips 66 used the net proceeds from the notes, together with a portion of the proceeds from $900 million of term loans received in late April 2017 and discussed below, to repay its outstanding 2.95% Senior Notes upon maturity in May 2017, for capital expenditures and for general corporate purposes.

Interest on the notes is a floating rate equal to three-month LIBOR plus 0.65% per annum for the 2019 Notes and three-month LIBOR plus 0.75% per annum for the 2020 Notes. Interest on both series of notes is payable quarterly in arrears on January 15, April 15, July 15 and October 15, commencing in July 2017. The 2019 Notes mature on April 15, 2019, and the 2020 Notes mature on April 15, 2020.

The term loans consist of a $450 million 364-day facility and a $450 million three-year facility. Interest on the term loans is a floating rate based on either the Eurodollar rate or the reference rate, plus a margin determined by our long-term credit ratings.

Shelf Registration

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Off-Balance Sheet Arrangements

In 2016, the operating lease commenced on our headquarters facility in Houston, Texas. Under this lease agreement, we have a residual value guarantee with a maximum future exposure of $554 million. The operating lease has a term of five years and provides us the option, at the end of the lease term, to request to renew the lease, purchase the facility, or assist the lessor in marketing it for resale.

We have residual value guarantees associated with railcar and airplane leases with maximum future exposures totaling $350 million. For information on our need to perform under the railcar lease guarantee, see the Capital Requirements section to follow, as well as Note 11—Guarantees, in the Notes to Consolidated Financial Statements.

Capital Requirements

For information about our capital expenditures and investments, see the “Capital Spending” section.

Our debt balance at June 30, 2017, and December 31, 2016, was $10.0 billion and $10.1 billion, respectively. Our debt-to-capital ratio was 30 percent at both June 30, 2017, and December 31, 2016. Our target debt-to-capital ratio is between 20 and 30 percent.

In May 2017, we repaid $1,500 million of 2.95% Senior Notes upon maturity with the funding from the April 2017 debt issuances discussed above.

Also in May 2017, we repaid $135 million of MSLP 8.85% Senior Notes due in 2019. This debt was assumed as a result of the consolation of MSLP. See Note 5—Business Combinations, in the Notes to the Consolidated Financial Statements, for additional information regarding MSLP.

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On May 3, 2017, our Board of Directors declared a quarterly cash dividend of $0.70 per common share. The dividend was paid on June 1, 2017, to shareholders of record at the close of business on May 18, 2017. On July 12, 2017, our Board of Directors declared a quarterly cash dividend of $0.70 per common share. This dividend is payable on September 1, 2017, to shareholders of record at the close of business on August 18, 2017.

Our Board of Directors at various times has authorized repurchases of our outstanding common stock, which aggregate to a total authorization of up to $9 billion. The share repurchases are expected to be funded primarily through available cash. The shares will be repurchased from time to time in the open market at our discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements. We are not obligated to acquire any particular amount of common stock and may commence, suspend or discontinue purchases at any time or from time to time without prior notice. During the first six months of 2017, we repurchased 8,390,954 shares at a cost of $666 million. Since the inception of our share repurchases in 2012 through June 30, 2017, we have repurchased a total of 113,795,603 shares at a cost of $8,104 million. Shares of stock repurchased are held as treasury shares.

During the first half of 2017, we contributed $15 million to our U.S. benefit plans and $17 million to our international benefit plans. We currently expect to make additional contributions of approximately $425 million to our U.S. benefit plans and $18 million to our international benefit plans during the remainder of 2017.

We own a 25 percent interest in the Dakota Access, LLC (DAPL) and Energy Transfer Crude Oil Company, LLC (ETCOP) joint ventures, which were formed to construct pipelines to deliver crude oil produced in the Bakken area of North Dakota to market centers in the Midwest and the Gulf Coast. In 2016, we and our co-venturer executed agreements, and an amendment to the original agreements, that provided we and our co-venturer would loan DAPL and ETCOP up to a maximum of $1,411 million and $76 million, respectively, with the amounts loaned by us and our co-venturer being proportionate to our ownership interests (Sponsor Loans). Also in 2016, DAPL and ETCOP secured a $2.5 billion facility (Facility) with a syndicate of financial institutions on a limited recourse basis with certain guarantees. Allowable draws under the Facility were initially reduced and finally suspended in September 2016 pending resolution of permitting delays. As a result, DAPL and ETCOP resumed making draws under the Sponsor Loans. In February 2017, DAPL was granted the lone outstanding easement required to complete work beneath the Missouri River. As a result, construction of the pipelines resumed and draws under the Facility were reinitiated and all outstanding Sponsor Loans were paid in February 2017. Construction on both pipelines was completed, with commercial operations beginning in June 2017. As of June 30, 2017, DAPL and ETCOP have an aggregate balance outstanding under the Facility of $2.5 billion.

In 2016, we and our co-venturer in WRB each made a $75 million partner loan to provide for WRB’s short-term operating needs. These partner loans were repaid in the first quarter of 2017.

During the first six months of 2017, we recognized an additional $24 million of the residual value deficiency of our leased railcars. The residual value deficiency of $42 million remaining at June 30, 2017, will be recognized on a straight-line basis with approximately 40 percent recognized through October 2017 and the remainder recognized through May 2019. Due to current market uncertainties, changes in the estimated fair values of railcars could occur, which could increase or decrease our currently estimated residual value deficiency. As of June 30, 2017, our maximum future exposure under the residual value guarantees was approximately $311 million. For additional information, see Note 11—Guarantees, in the Notes to Consolidated Financial Statements.

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Capital Spending

	Millions of Dollars Six Months Ended June 30	
	2017	2016
Capital Expenditures and Investments		
Midstream	$ 381	730
Chemicals	—	—
Refining	475	538
Marketing and Specialties	38	37
Corporate and Other	34	65
Total consolidated from continuing operations	$ 928	1,370
Selected Equity Affiliates*		
DCP Midstream	$ 104	55
CPChem	387	541
WRB	64	80
	$ 555	676

* Our share of capital spending.

Midstream

During the first six months of 2017, capital spending in our Midstream segment included construction activities related to increasing storage capacity at our crude oil and petroleum products terminal located near Beaumont, Texas, wrap-up activities related to our Freeport LPG Export Terminal and spending associated with return, reliability and maintenance projects in our Transportation and NGL businesses. Other major construction activities included the further development of Phillips 66 Partners’ 40-percent-owned joint venture Bayou Bridge Pipeline, and the development of two crude oil pipelines by our 25-percent-owned joint ventures, DAPL and ETCOP. Construction on the DAPL and ETCOP pipelines was completed, with commercial operations beginning in June 2017.

During the first six months of 2017, DCP Midstream had a self-funded capital program, and thus had no new capital infusions from us or our co-venturer. During this period, on a 100 percent basis, DCP Midstream’s capital expenditures and investments were approximately $207 million, primarily for expansion capital expenditures including construction of the Mewbourn 3 plant and investments in the Sand Hills Pipeline joint venture, and maintenance capital expenditures for existing assets.

Chemicals

During the first six months of 2017, CPChem had a self-funded capital program, and thus required no new capital infusions from us or our co-venturer. During this period, on a 100 percent basis, CPChem’s capital expenditures and investments were $774 million, primarily for its U.S. Gulf Coast Petrochemicals Project. We expect CPChem to self-fund its capital program in 2017.

Refining

Capital spending for the Refining segment during the first six months of 2017 was primarily for air emission reduction projects to meet new environmental standards, refinery upgrade projects to increase accessibility of advantaged crudes and improve product yields, improvements to the operating integrity of key processing units and safety-related projects.

Major construction activities included:

- Installation of facilities to comply with U.S. Environmental Protection Agency (EPA) Tier 3 gasoline regulations at the Sweeny and Bayway refineries.
- Installation of facilities to improve processing of advantaged crudes at the Billings and Lake Charles refineries.

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- Installation of facilities to improve clean product yield at the Bayway and Ponca City refineries, as well as the jointly owned Wood River refinery.

Our project to increase advantaged crude processing at the Billings Refinery was completed in June 2017 and is operating at design specifications.

Generally, our equity affiliates in the Refining segment are intended to have self-funding capital programs.

Marketing and Specialties

Capital spending for the M&S segment during the first six months of 2017 was primarily for reliability and maintenance projects and projects targeted at developing our new international sites.

Contingencies

A number of lawsuits involving a variety of claims that arose in the ordinary course of business have been filed against us or are subject to indemnifications provided by us. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for financial recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the case of income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other potentially responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Legal and Tax Matters

Our legal and tax matters are handled by our legal and tax organizations. These organizations apply their knowledge, experience and professional judgment to the specific characteristics of our cases and uncertain tax positions. We employ a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases and enables the tracking of those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. In the case of income-tax-related contingencies, we monitor tax legislation and court decisions, the status of tax audits and the statute of limitations within which a taxing authority can assert a liability.

Environmental

Like other companies in our industry, we are subject to numerous international, federal, state and local environmental laws and regulations. For a discussion of the most significant of these environmental laws and regulations, including those with associated remediation obligations, see the "Environmental" section in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2016 Annual Report on Form 10-K.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential

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liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2016, we reported that we had been notified of potential liability under CERCLA and comparable state laws at 31 sites within the United States. During the first six months of 2017, there were two new sites for which we received notice of potential liability and three sites were deemed resolved and closed, leaving 30 sites with potential liability at June 30, 2017.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect on our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) emissions reduction, including various regulations proposed or issued by the EPA. These proposed or promulgated laws apply or could apply in states and/or countries where we have interests or may have interests in the future. Laws regulating GHG emissions continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws potentially could have a material impact on our results of operations and financial condition as a result of increasing costs of compliance, lengthening project implementation and agency review items, or reducing demand for certain hydrocarbon products. We continue to monitor legislative and regulatory actions and legal proceedings globally relating to GHG emissions for potential impacts on our operations.

For examples of legislation and regulation or precursors for possible regulation that do or could affect our operations, see the “Climate Change” section in Management’s Discussion and Analysis of Financial Condition and Results of Operations in our 2016 Annual Report on Form 10-K.

We consider and take into account anticipated future GHG emissions in designing and developing major facilities and projects, and implement energy efficiency initiatives to reduce such emissions. GHG emissions, legal requirements regulating such emissions, and the possible physical effects of climate change on our coastal assets are incorporated into our planning, investment and risk management decision-making.

NEW ACCOUNTING STANDARDS

In February 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2017-05, “Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets.” This ASU clarifies the scope and accounting for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. This ASU will eliminate the use of carryover basis for most nonmonetary exchanges, including contributions of assets to equity method joint ventures. These amendments could result in the entity recognizing a gain or loss on the sale or transfer of nonfinancial assets. Public entities should apply the guidance in ASU No. 2017-05 to annual periods beginning after December 15, 2017, including interim periods within those periods. We are currently evaluating the provisions of ASU No. 2017-05.

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business,” which clarifies the definition of a business with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as acquisitions of assets or businesses. The amendment provides a screen for determining when a transaction involves an acquisition of a business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, then the transaction is not considered an acquisition of a business. If the screen is not met, then the amendment requires that to be considered a business, the operation must include at a minimum an input and a substantive process that together significantly contribute to the ability to create an output. The guidance may reduce the number of transactions accounted for as business acquisitions. Public business entities should apply the guidance in ASU No. 2017-01 to annual periods beginning after December 15, 2017, including interim periods within those periods, with early adoption permitted. The amendments should be applied prospectively and no disclosures are required at the effective date. We are currently evaluating the provisions of ASU No. 2017-01.

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In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” The new standard amends the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. Public business entities should apply the guidance in ASU No. 2016-13 for annual periods beginning after December 15, 2019, including interim periods within those annual periods. Early adoption will be permitted for annual periods beginning after December 15, 2018. We are currently evaluating the provisions of ASU No. 2016-13 and assessing the impact on our financial statements.

In February 2016, the FASB issued ASU No. 2016-02, “Leases (Topic 842).” In the new standard, the FASB modified its determination of whether a contract is a lease rather than whether a lease is a capital or operating lease under the previous accounting principles generally accepted in the United States (GAAP). A contract represents a lease if a transfer of control occurs over an identified property, plant or equipment for a period of time in exchange for consideration. Control over the use of the identified asset includes the right to obtain substantially all of the economic benefits from the use of the asset and the right to direct its use. The FASB continued to maintain two classifications of leases—financing and operating—which are substantially similar to capital and operating leases in the previous lease guidance. Under the new standard, recognition of assets and liabilities arising from operating leases will require recognition on the balance sheet. The effect of all leases in the statement of comprehensive income and the statement of cash flows will be largely unchanged. Lessor accounting will also be largely unchanged. Additional disclosures will be required for financing and operating leases for both lessors and lessees. Public business entities should apply the guidance in ASU No. 2016-02 for annual periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. We are currently evaluating the provisions of ASU No. 2016-02 and assessing its impact on our financial statements.

In January 2016, the FASB issued ASU No. 2016-01, “Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,” to meet its objective of providing more decision-useful information about financial instruments. The majority of this ASU’s provisions amend only the presentation or disclosures of financial instruments; however, one provision will also affect net income. Equity investments carried under the cost method or lower of cost or fair value method of accounting, in accordance with current GAAP, will have to be carried at fair value upon adoption of ASU No. 2016-01, with changes in fair value recorded in net income. For equity investments that do not have readily determinable fair values, a company may elect to carry such investments at cost less impairments, if any, adjusted up or down for price changes in similar financial instruments issued by the investee, when and if observed. Public business entities should apply the guidance in ASU No. 2016-01 for annual periods beginning after December 15, 2017, and interim periods within those annual periods, with early adoption prohibited. We are currently evaluating the provisions of ASU No. 2016-01. Our initial review indicates that ASU No. 2016-01 will have a limited impact on our financial statements.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” This ASU and other related updates are intended to improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets and expand disclosure requirements. In August 2015, the FASB issued ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The amendment in this ASU defers the effective date of ASU No. 2014-09 for all entities for one year. Public business entities should apply the guidance in ASU No. 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted only as of annual reporting periods beginning after December 31, 2016, including interim reporting periods within that reporting period. Retrospective or modified retrospective application of the accounting standard is required. We are currently evaluating the provisions of ASU No. 2014-09 and assessing the impact on our financial statements. As part of our assessment work to-date, we have formed an implementation work team, completed training on the new ASU's revenue recognition model and are continuing our contract review and documentation. Our expectation is to adopt the standard on January 1, 2018, using the modified retrospective application. In addition, we expect to present revenue net of sales-based taxes collected from our customers resulting in no impact to earnings. Sales-based taxes include excise taxes on petroleum product sales as noted on our consolidated statement of income. Our evaluation of the new ASU is ongoing, which includes understanding the impact of adoption on earnings from equity method investments. Based upon our analysis to-date, we have not identified any other material impact on our financial statements other than disclosures.

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CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "sho "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about us and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- Fluctuations in NGL, crude oil, petroleum products and natural gas prices and refining, marketing and petrochemical margins.
- Failure of new products and services to achieve market acceptance.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating our facilities or transporting our products.
- Unexpected technological or commercial difficulties in manufacturing, refining or transporting our products, including chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our NGL, crude oil, natural gas and refined products.
- The level and success of drilling and quality of production volumes around DCP Midstream's assets and its ability to connect supplies to its gathering and processing systems, residue gas and NGL infrastructure.
- Inability to timely obtain or maintain permits, including those necessary for capital projects; comply with government regulations; or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future capital projects.
- Potential disruption or interruption of our operations due to accidents, weather events, civil unrest, political events, terrorism or cyber attacks.
- International monetary conditions and exchange controls.
- Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.
- Liability resulting from litigation or for remedial actions, including removal and reclamation obligations under environmental regulations.
- General domestic and international economic and political developments including: armed hostilities; expropriation of assets; changes in governmental policies relating to NGL, crude oil, natural gas or refined product pricing, regulation or taxation; and other political, economic or diplomatic developments.
- Changes in tax, environmental and other laws and regulations (including alternative energy mandates) applicable to our business.
- Limited access to capital or significantly higher cost of capital related to changes to our credit profile or illiquidity or uncertainty in the domestic or international financial markets.
- The operation, financing and distribution decisions of our joint ventures.
- Domestic and foreign supplies of crude oil and other feedstocks.
- Domestic and foreign supplies of petrochemicals and refined products, such as gasoline, diesel, aviation fuel and home heating oil.

- Governmental policies relating to exports of crude oil and natural gas.
- Overcapacity or undercapacity in the midstream, chemicals and refining industries.
- Fluctuations in consumer demand for refined products.
- The factors generally described in Item 1A.—Risk Factors in our 2016 Annual Report on Form 10-K.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our commodity price risk and interest rate risk at June 30, 2017, did not differ materially from the risks disclosed under Item 7A of our 2016 Annual Report on Form 10-K.

Item 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of June 30, 2017, with the participation of management, our Chairman and Chief Executive Officer and our Executive Vice President, Finance and Chief Financial Officer carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of June 30, 2017.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the quarterly period ended June 30, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment, for this reporting period. There was one new matter that arose during the second quarter of 2017. There were no material developments that occurred with respect to matters previously reported in our 2016 Annual Report on Form 10-K or our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were decided adversely to Phillips 66, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

Our U.S. refineries are implementing two separate consent decrees, regarding alleged violations of the Federal Clean Air Act, with the EPA, five states and one local air pollution agency. Some of the requirements and limitations contained in the decrees provide for stipulated penalties for violations. Stipulated penalties under the decrees are not automatic, but must be requested by one of the agency signatories. As part of periodic reports under the decrees or other reports required by permits or regulations, we occasionally report matters that could be subject to a request for stipulated penalties. If a specific request for stipulated penalties meeting the reporting threshold set forth in SEC rules is made pursuant to these decrees based on a given reported exceedance, we will separately report that matter and the amount of the proposed penalty.

New Matter
On June 27, 2017, Phillips 66 settled with the San Francisco Regional Water Quality Control Board for certain exceedances of copper and chlorine under the Rodeo Refinery’s National Pollutant Discharge Elimination System permit. The payment agreed was $109,000.

Item 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A of our 2016 Annual Report on Form 10-K.

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Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS
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 Plans or Programs**	Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
April 1-30, 2017	1,233,570	$ 77.44	1,233,570	$ 1,181
May 1-31, 2017	1,719,177	78.89	1,719,177	1,045
June 1-30, 2017	1,903,745	78.60	1,903,745	896
Total	4,856,492	$ 78.41	4,856,492	

* Includes repurchase of shares of common stock from company employees in connection with the company's broad-based employee incentive plans, when applicable.
** Our Board of Directors has authorized repurchases totaling up to $9 billion of our outstanding common stock. The current authorization was announced in
July 2014, in the amount of $2 billion, and increased to $4 billion as announced in October 2015. The authorization does not have an expiration date. The
share repurchases are expected to be funded primarily through available cash. The shares under these authorizations will be repurchased from time to time
in the open market at the company's discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements.
We are not obligated to acquire any particular amount of common stock and may commence, suspend or discontinue purchases at any time or from time to
time without prior notice. Shares of stock repurchased are held as treasury shares.

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Item 6. EXHIBITS

Exhibit Number	Exhibit Description
4.1	Indenture, dated as of April 21, 2017, among Phillips 66, as issuer, Phillips 66 Company, as guarantor, and Wells Fargo Bank, National Association, as trustee, in respect of senior debt securities of Phillips 66 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K dated April 21, 2017).
4.2	Form of the terms of the 2019 Notes and the 2020 Notes, including the form of the 2019 Notes and the 2020 Notes (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K dated April 21, 2017).
12	Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document.
101.SCH	XBRL Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Labels Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

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SIGNATURES

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

PHILLIPS 66

/s/ Chukwuemeka A. Oyolu
Chukwuemeka A. Oyolu
Vice President and Controller
(Chief Accounting and Duly Authorized Officer)

Date: August 1, 2017