SHELF DRILLING HOLDINGS, LTD.

Financial Information, Financial Statements and Other Information Prepared Equivalent to Rules and Regulations of the United States Securities and Exchange Commission for 10-K Filings

December 31, 2016

SHELF DRILLING HOLDINGS, LTD.
Annual Report on Form 10-K Equivalent for the Year Ended December 31, 2016

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This report should be read in its entirety as it pertains to Shelf Drilling Holdings, Ltd. Except where indicated, the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements are combined. References in this Annual Report on Form 10-K to "Shelf,", "SDHL", the "Company," "Group," "we," "us," "our" and words of similar meaning refer collectively to Shelf Drilling Holdings, Ltd. and its consolidated subsidiaries. Shelf Drilling Holdings, Ltd. is an indirect subsidiary of Shelf Drilling, Ltd.

FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not historical facts are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include words or phrases such as "anticipate," "believe," "estimate," "expect," "intend," "plan," "project," "could," "may," "might," "should," "will" and similar words and specifically include statements regarding expected financial performance; expected utilization, day rates, revenues, operating expenses, contract terms, contract backlog, capital expenditures and deferred costs, insurance, financing and funding; the timing of availability, delivery, mobilization, contract commencement or relocation or other movement of rigs; current or future rig construction (including construction in progress and completion thereof), enhancement, upgrade, repair or reactivation and timing thereof; the suitability of rigs for future contracts; general market, business and industry conditions, trends and outlook; future operations; the impact of increasing regulatory complexity; expected contributions from our newbuild rigs; expense management; and the likely outcome of litigation, legal proceedings, investigations or insurance or other claims and the timing thereof. These forward-looking statements speak only as of the date of this report on Form 10-K and we undertake no obligation to revise or update any forward-looking statement for any reason, except as required by law. Such statements are subject to numerous risks, uncertainties and assumptions that may cause actual results to vary materially from those indicated, including:

- the Company's ability to renew or extend contracts, enter into new contracts when such contracts expire, and negotiate the dayrates and other terms of such contracts;
- the demand for the Company's drilling rigs;
- changes in worldwide rig supply and demand, competition or technology, including as a result of delivery of newbuild drilling rigs;
- the expectations of the Company's customers relating to future energy prices and ability to obtain drilling permits;
- the impact of variations in oil and gas production and prices and demand in hydrocarbons;
- the impact of variations in demand for the Company's products and services;
- sufficiency and availability of funds for required capital expenditures and deferred costs, working capital and debt service;
- the Company's levels of indebtedness, covenant compliance and access to future capital;
- the level of reserves for accounts receivables;
- the disproportionate changes in operating and maintenance costs compared to changes in operating revenues;
- downtime and other risks associated with offshore rig operations or rig relocations, including rig or equipment failure, damage and other unplanned repairs;
- the expected completion of shipyard projects including the timing of newbuild rigs construction and delivery and the return of idle rigs to operations;
- future capital expenditures and deferred costs, refurbishment, reactivation, transportation, repair and upgrade costs
- the liabilities and restrictions under coastwise and other laws of the jurisdictions in which the Company operates and regulations protecting the environment;
- the outcomes of any litigations, investigations, claims and disputes and their effects on the Company's financial condition and results of operations;
- effects of accounting changes and adoption of accounting policies;
- expectations regarding offshore drilling activity and dayrates, market conditions, operating revenues, operating and maintenance expense, insurance coverage, insurance expense and deductibles, interest expense and other matters with regard to outlook and future earnings;
- potential asset impairment as a result of future decline in demand for shallow water drilling rigs;
- the market value of the Company's drilling rigs and of any rigs the Company acquires in the future may decrease;
- our ability to attract and retain skilled personnel on commercially reasonable terms, whether due to labor regulations, unionization or otherwise;
- the security and reliability of our technology systems and service providers ;
- adverse changes in foreign currency exchange rates;
- changes in general economic, fiscal and business conditions in jurisdictions in which the Company operates and elsewhere;
- our ability to obtain financing and pursue other business opportunities may be limited by our debt levels, debt agreement restrictions and the credit ratings assigned to our debt by independent credit rating agencies; and
- the other factors listed in Section 1A. - Risk Factors.

Part I

Item 1. Business

General

Shelf Drilling Holdings, Ltd ("SDHL") was incorporated on August 24, 2012 ("inception") as a private corporation in the Cayman Islands. SDHL is a holding company with no significant operations or assets other than owned interests in its direct and indirect subsidiaries. SDHL and its majority owned subsidiaries (together, the "Company") provide shallow-water drilling services to the oil and natural gas industry. The Company's corporate offices are in Dubai, United Arab Emirates ("UAE"), geographically close to its operations in the Middle East, South East Asia, India, West Africa and the Mediterranean. The Company is 100% owned by Shelf Drilling Intermediate, Ltd. ("SDIL") and is indirectly owned by Shelf Drilling, Ltd. ("SDL"), the ultimate parent company.

The Company is a leading international shallow water offshore drilling contractor engaged in the provision of equipment and services for the drilling, completion and workover of offshore oil and natural gas wells. The Company is primarily engaged in development and workover activity on producing assets in shallow water of up to 400 feet in water depth. The Company owns 35 independent cantilever jackup rigs, one swamp barge and one new build jackup under construction. The Company is the world's largest contractor of independent-leg cantilever jackup rigs by number of rigs.

Recent events

In April, 2016, the Company sold two stacked rigs, Adriatic V and Adriatic VI.

On September 29, 2016, the Company took delivery of one of the two newbuild high specification jackup rigs (the "Newbuilds") from Lamprell Energy Limited (the "Builder") which was under construction since 2014. After completion of the customer acceptance requirements on December 1, 2016, the rig, which is under sale and leaseback transaction, commenced a five-year contract with Chevron Thailand Exploration and Production, Ltd ("Chevron").

On December 2, 2016, SDL and SDL's wholly owned subsidiaries Shelf Drilling Midco, Ltd. ("Midco") and SDHL, signed an Amended and Restated Transaction Support Agreement ("A&R TSA") with certain equity sponsors and holders, in the aggregate, of (a) approximately 85.6% of principal amount of the 8.625% Senior Secured Notes ("SDHL Senior Secured Notes") and (b) 100% of principal amount of the $350 million Midco Term Loan to support certain transactions to refinance the Company's debt facilities, subject to terms and conditions. On January 12, 2017 ("Closing Date"), the Company successfully concluded the refinancing of its long term debt facilities after fulfilling the conditions precedent under the A&R TSA.

As a result, SDHL issued $502.835 million of new 9.5% Senior Secured Notes due November 2020 ("9.5% Senior Secured Notes"). These notes were issued in exchange and cancellation of $444.585 million of 8.625% Senior Secured Notes due November 2018 in accordance with the terms and conditions of the Offering Memorandum to Exchange Notes and Solicit Consents (of which $28.5 million were settled for cash), and $86.75 million in exchange for partial settlement of the $350 million Midco Term Loan. As of the Closing Date, $30.415 million of 8.625% Senior Secured Notes remain outstanding after issuance of $416.085 million 9.5% Senior Secured Notes, principal payment of $28.5 million in cash and incentive fee payment of $5.7 million in cash.

At the Closing Date, Midco also fully settled the outstanding $350 million term loan. The term loan was settled in exchange for the issuance of $166.7 million of SDL Preferred Shares to certain equity Sponsors, issuance of $86.75 million of new 9.5% Senior Secured Notes and $85.75 million in cash. This settlement resulted in a gross gain of $10.8 million (excluding transaction costs and unamortized original issue discount and deferred financing costs write off). The equity Sponsors paid $100 million in cash directly to the Midco lenders in exchange for the purchase of $166.7 million of the term loan.

Simultaneously, the Company successfully amended the SDHL Revolver to extend the maturity date to April 2020, permanently reduce the facility from $200 million to $160 million and amend certain other terms of this agreement.

At December 31, 2016, the Company recorded a non-cash impairment loss of $47.1 million in relation to three rigs out of which one rig was impaired to salvage value. This non-cash impairment is included in loss on impairment of assets in the consolidated statements of operations.

History

As a result of a definitive agreement with Transocean Inc. (the “Seller”, “Transocean”) entered into on September 9, 2012 (the “Acquisition”) which closed on November 30, 2012, the Company acquired, both directly and indirectly through the direct purchase of six rigs and the purchase of certain of Transocean’s affiliates, a total of 37 independent-leg cantilever jackup drilling rigs and one swamp barge. The Acquisition was funded with equity contributions from its parent totaling $450 million, debt financing, as well as a $195 million preferred share investment in SDIL from Transocean. The preferred shares were subsequently fully redeemed.

Due to a number of regulatory and operational constraints, several individual rig Operating Agreements were entered into with Transocean concurrently with the closing of the Acquisition, whereby Transocean agreed on behalf of the Company to operate, for a transitional period of time, certain of the rigs in the Acquisition, submit invoices and collect revenue from the customers under the associated drilling contracts and pay direct costs and expenses incurred while operating the rigs. Pursuant to these Operating Agreements, Transocean also agreed to transfer the net economic benefits of each drilling contract (customer collections less direct costs and expenses) to the Company on a monthly basis. In addition, the Company agreed to pay Transocean a daily fixed fee per rig for in-country onshore support and a daily fixed fee per rig for corporate support services. The Operating Agreements remained in effect until expiration, novation or assignment to the Company of the underlying drilling contracts that were in place at the time of the Acquisition, originally resulting in effective terms ranging from nine months to 27 months. Until the expiration, novation or assignment of the underlying drilling contracts, Transocean retained possession of the materials and supplies associated with the rigs under the Operating Agreements. Upon expiration, novation or assignment of the related drilling contracts, the individual rig Operating Agreements terminated and the Company assumed operation of the rigs and acquired related inventory. At the close of the Acquisition, Transocean operated 25 rigs under Operating Agreements. The Company was able to novate or assign all of our customer contracts, so that by January 1, 2015, no further rigs were subject to the Operating Agreements and we were operating all rigs in the fleet.

Revenues generated by rigs operated under the Operating Agreements have been recorded by the Company as net revenue. Net revenue represents customer revenue less expenses related to the operation of the rigs (comprised of: personnel; asset management and maintenance; operating, miscellaneous and administration expenses; shore based fixed fees; corporate services fixed fees; and taxes paid by Transocean). Upon commencement of independent operations of each rig, the Company started to recognize these revenues and costs on a gross basis in its consolidated statement of operations. For this reason, the Company’s revenue, operating costs, general and administrative costs and income taxes have increased in 2016 and 2015 compared to 2014, as direct operations of all rigs that were previously managed by Transocean under the Operating Agreements were assumed by the Company as of January 1, 2015.

Transocean also agreed to provide, for a period of up to 18 months, support services under a Transition Services Agreement entered into with Transocean concurrently with the closing of the Acquisition. Under the Transition Services Agreement, Transocean agreed to provide various corporate and local services to the Company for rigs owned and operated by the Company. These services were generally provided on a pre-determined daily fixed fee per rig basis or reimbursed at costs equivalent to those incurred by Transocean for goods, services or personnel. The services include use of Transocean’s enterprise resource planning (‘‘ERP’’) system for accounting, fixed assets, treasury, supply chain management and maintenance scheduling, human resource systems, information technology infrastructure and helpdesk support. The costs of the support services provided to rigs operated by the Company are included in the Company’s general and administrative expenses. As of December 31, 2014, the Company had terminated the Transition Services Agreement and independently operated all services previously covered under this agreement.

Strategy

The Company follows a focused ‘‘fit for purpose’’ business strategy and operational approach based on the capabilities of our fleet and the requirements of specific geographic markets and customers where we believe demand for shallow water drilling services present the best opportunities for growth. This ‘‘fit for purpose’’ strategy entails the maintenance of a cost efficient organizational and operational structure designed to specifically address the shallow water jackup markets which the Company targets. Management considers the capabilities of the Company’s fleet to be well suited for the benign shallow water areas in which it operates.

Operations

The Company’s contract backlog at December 31, 2016, 2015 and 2014 totaled approximately $1.7 billion, $2.3 billion and $3.2 billion, with a weighted average backlog dayrate at December 31, 2016, 2015 and 2014 of $96.7 thousand, $99.4 thousand and $123.8 thousand respectively.

For the year ended December 31, 2016, the operational uptime performance of our fleet was 98.7% and we achieved a 0.25 total recordable incident rate. This compares to a fleet uptime performance of 98.6% and 98.5% for the years ended December 31, 2015 and 2014, respectively. The total recordable incident rate was 0.22 and 0.48 at December 31, 2015 and 2014, respectively.

Revenue is primarily generated by the dayrates for each rig pursuant to customer contracts. For the year ended December 31, 2016, the Company had Adjusted Revenues of $684.3 million and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") of $295.6 million, compared to Adjusted Revenues of $1.0 billion and Adjusted EBITDA of $372.2 million for the comparable 2015 period. For the year ended December 31, 2014, the Adjusted Revenues and Adjusted EBITDA were $1.3 billion and $541.2 million, respectively.

Competitive Strengths

The Company believes its primary competitive strengths include the following:

''Fit for purpose'' Strategy Focused on Shallow Water Drilling

Our operational focus is "fit for purpose" in all aspects of the business. We have established and maintain a cost efficient organizational and operational structure designed specifically to support shallow water drilling operations. We believe our fleet is well suited for the majority of drilling programs in the benign shallow water environments which we target, which optimizes our success in meeting the long term demands of our customer base.

The establishment of the Company in late 2012 as a standalone business provided management with the opportunity to design a from the ground-up structure and philosophy that is cost efficient and focuses on providing safe and reliable service to our customers. By establishing a corporate office in Dubai, centrally located to the customers and geographic regions in which we operate, the Company enjoys proximity to several high quality shipyards and other service providers which have eliminated the need for numerous regional offices. The result is a cost-efficient administrative structure in a central location providing direct, scheduled air service to field operations enabling an enhanced focus on the provision of high quality and responsive service to our customers.

Another key pillar of our strategy is an emphasis on national content. The Company employs a high proportion of national employees in many of the markets in which we operate, from the supervisors who oversee the operations on the Company's fleet of rigs to the country managers who provide the oversight and interaction with the customers' shore based management teams. Local employees and contractors represent approximately 83% of our total global workforce. In our key markets, the percentage of nationals and contractors exceeds this average with Egypt employing approximately 100% national and contractor workforces while India and Nigeria both have 97% national and contractor workforces as of December 31, 2016. This strategy further strengthens customer and governmental relationships, particularly with National Oil Companies ("NOCs"), and produces relatively lower employee turnover as well as a lower cost base.

The Company is a "pure-play" shallow water drilling contractor. Management believes a dedicated focus in this market enables the Company to conduct operations and marketing more effectively than many of our more diversified competitors who are also present in deepwater drilling operations.

In deploying the Company's rigs, management has primarily focused on NOCs and customers who have similarly long term drilling programs. These contracts are often associated with development or workover drilling which management considers a better prospect for continuous, long-term deployments. At December 31, 2016, 25 of our rigs were under contract, out of which 18 rigs were contracted with NOCs or NOC joint ventures, six rigs (including a newbuild rig under construction) were contracted with Integrated Major Oil Companies ("IOCs") and one rig was contracted with an independent oil and gas company. We attempt to strategically position our rigs in geographic markets where we anticipate their specific capabilities will offer longer-term suitability, taking into account both immediate economic potential and future growth potential, as well as political risk. The availability of skilled local talent, adequate local shipyard and other shore-based infrastructure as well as proximity to the Company's existing footprint are also considered.

The Company's strategy does not contemplate speculative upgrades or the acquisition or construction of new rigs based solely on the specifications or capabilities of the equipment. Rather, management works actively with our customers to understand current and future shallow water drilling needs and responds with competitive "fit-for-purpose" offers. This strategy enhances customers' ability to source rigs capable of addressing specific drilling needs at competitive dayrates. At the same time, the Company is able to limit potentially unproductive capital investment.

Leading Position in Significant Oil Producing International Jackup Markets

The Company has market leading positions in specific shallow water markets accounting for some of the most globally significant offshore oil reserves. The breakeven economics in these geographic areas frequently compare favorably with many other offshore, and even onshore, plays.

Management believes that operating in these lower breakeven regions provides a relatively better downside hedge against curtailment of development activities by oil and gas companies in lower commodity price environments. Activity in our target markets is generally characterized by substantial and growing NOC activity levels. NOCs have a sustained, demonstrated long-term commitment to shallow water markets. The NOCs tend to offer extended terms in their drilling contract awards, some as long as ten years. Shallow water resources are well understood by the industry and the majority of activity in these areas is focused on the development and workover of proven reserves rather than on exploration.

Measured by number of rigs, the Company was the world's largest contractor of independent-leg cantilever jackup rigs at December 31, 2016. Since 2015, the jackup rig market is experiencing utilization and day rate challenges which negatively impact the supply and demand balance worldwide. However, our market-leading position in various shallow water markets enables customer responsiveness, fleet use efficiencies, economies of scale and operational flexibility. Given the importance of safety and operational reliability in the industry, NOCs and IOCs typically prefer to contract with market leaders with proven track records and management believes this confers a significant advantage on the Company. Our rigs and personnel frequently have significant history with existing and potential customers, particularly the NOCs and IOCs, conferring valuable credibility as we compete with both international and regional operators.

Proven Operator with Strong Focus on Safety, Uptime and Project Execution

The Company's rigs, employees and management have substantial experience operating in all our core markets. With demonstrated strong operational metrics and a history of successful execution in major projects, the management believes the Company is well positioned as a provider of choice for shallow water offshore drilling services and is well positioned to compete effectively in our core markets.

Management believes the Company's fleet is particularly well suited to meet customer specific demands in our target markets. This is evidenced by fleet operational uptime consistently above 98.5% since 2012.

Management intends to continue to devote significant resources to HSE programs, reliability and operational excellence and to promote a culture of diligence and minimization of organizational risk. We believe that a continued focus in these areas will strengthen relationships with our stakeholders and with government agencies in local communities in which we operate.

We believe we have demonstrated a capacity to successfully execute major projects in a timely and cost effective fashion. In successfully acquiring a fleet of 38 rigs, the Company has integrated operations across multiple jurisdictions and established robust and reliable information technology, human resources, supply chain and other back office functions. We have successfully completed the reactivations of five rigs which were stacked at the time of the Acquisition, including two rigs that were under reactivation by Transocean. Additionally, since the Acquisition, a total of 21 Special Periodic Surveys, 44 Underwater Inspections in Lieu of Dry-docking ("UWILDs") and 18 contract preparation projects have also been accomplished with all projects typically coming in substantially on time and on budget.

Further, in September 2016, the Company has successfully taken delivery of the first newbuild rig from Lamprell within budget and on time. The construction project was unique in that it was a collaborative effort involving the customer, the rig builder and the Company's project execution teams. The rig commenced operations successfully on December 1, 2016 as per the original plan agreed with the customer in May 2014.

Strong Customer Relationships Leading to Substantial Contract Backlog with High Quality and Diverse Customer Base

Our executive leadership and employees have long standing relationships with the Company's customers. We believe these relationships provide a competitive advantage, since customers tend to have a preference for established offshore drilling contractors who have a demonstrable track-record of providing reliable and safe jackup drilling operations. We believe our scale and focus on the shallow water market, as well as our "fit for purpose" fleet, has further established the Company's reputation with its customers in the markets in which we operate. Some of our key customers are as follows:

- Oil and Natural Gas Corporation ("ONGC" - the national oil company in India) with the Company operating 8 of 36 total contracted jackups as at December 31, 2016;

- Saudi Aramco (the national oil company in Saudi Arabia) with the Company operating 6 of 44 total contracted jackups as at December 31, 2016;

- Abu Dhabi Marine Operating Company ("ADMA-OPCO"), a subsidiary of Abu Dhabi National Oil Company ("ADNOC" – the oil company in Abu Dhabi, UAE) with the Company operating 2 of 15 (including 13 rigs operated by a related party of ADNOC) total contracted jackups as at December 31, 2016; and

- Chevron, with the Company operating 2 of 8 total contracted jackups as at December 31, 2016.

(Source: Company Information and IHS ODS Petrodata)

As of December 31, 2016, the Company's contract backlog totaled $1.7 billion compared with $1.5 billion at the time of the Acquisition. The Company's dedicated customer focus has resulted in a relatively better performance compared to its competitors. In the year ended December 31, 2016, the Company secured contracts and extensions worth approximately $283.5 million.

The Company's contract backlog is diversified across its fleet, with no one rig accounting for greater than 16% of the contract backlog as of December 31, 2016. We believe this diversity reduces the risk of non-conversion of our contract backlog into reportable revenues. At December 31, 2016, this backlog diversification exists across our core operating areas of Middle East / North Africa / Mediterranean (53%); Southeast Asia; (33%); India (11%) and; West Africa (3%).

Reaching certain threshold levels of exposure to key global jackup customers provides economies of scale to the Company's operations, providing leverage regarding acceptance levels of service, operating and equipment preferences and other important criteria utilized by our core customers. Management views these matters as central to our success in maximizing rig uptime while minimizing contract intervals. Our top four customers, who accounted for 90% of contract backlog as at December 31, 2016, also accounted for 72% of revenues for the year ended December 31, 2016. This level of engagement with our customers along with their strong credit profile further enhances the Company's ability to convert contract backlog into reportable revenue in the future.

Experienced Management Team Focused on Profitable Growth

The Company's management team has substantial experience in both offshore drilling and the wider oil and gas industry, and brings significant expertise to the commercial, technical, operational and financial areas. The team's dedicated focus on shallow water drilling is a key factor enabling the requisite quality and cost controls needed to execute the "fit for purpose" strategy. The Company's senior executives held leadership roles with listed offshore drilling companies. Their experience encompasses operating in all key shallow water drilling markets and working with major NOC and IOC customers. Additional value is provided through previous experience in operating many of the rigs in the Company's fleet. Management's considerable knowledge and experience enhances our ability to operate effectively through industry cycles while providing valuable insight to identifying and executing business opportunities.

The management team have established a track record of growing and re-contracting the Company's active fleet as major capital projects were successfully delivered substantially on time and at or below budget.

Customer Contracts

The Company's drilling contracts are typically awarded on an individual basis and vary in terms and rates depending on the operational nature, duration, amount and type of equipment and services, geographic area, market conditions and other variables. Contracts terms range in length from the time necessary to drill or workover one well up to several years. The methods through which we pursue new business vary significantly. Small independent oil and natural gas companies are generally less likely to require formal tender processes, while NOCs are more likely to require participation in full tender exercises prior to awarding new contracts.

We believe we have a number of competitive advantages that enable us to win new contracts. These factors include: (i) a sole focus on shallow water drilling; (ii) the specifications, flexibility and suitability of the Company's drilling rigs which make them fit for purpose in the markets where the Company operates; (iii) the Company's favorable HSE track record; (iv) the operational uptime record of the Company's fleet; (v) the operational history of certain of the Company's rigs with its core customers; (vi) the depth of experience of the Company's management and local workforce; and (vii) strong customer relationships.

Our customer base comprises NOCs, IOCs and independent oil and gas companies including Saudi Aramco, ONGC, Chevron, Adma-Opco, Total and ENI who contract the Company's rigs for varying durations. The Company believes that its ability to maintain relationships with, and to win repeat business from, its existing customers is critical to its stability and growth of cash flows.

Management believes that extending current contracts or entering into additional contracts with existing customers benefits both the Company and its customers. Advantages from our customers' perspective include: (i) rigs and crews are readily available on the work site, eliminating additional mobilization expense; (ii) the availability of existing equipment which meets customer specifications both operationally and from a safety perspective; and (iii) high degree of expectation that the previously utilized rig will continue to meet the customer's needs in that our employees are familiar with the customer's policies and procedures. Additionally, contract extensions or entering into new contracts with existing customers typically simplify contract negotiations and related legal and administrative requirements even during periods of intense price competition. The Company believes that these are important factors which provide competitive advantages in securing contracts.

If an existing customer fails to renew a contract, the Company must secure a new contract for that rig. In the year ended December 31, 2016, of the 11 contracts or extensions we entered into, seven represented renewals of contracts with the existing customer. Based on customer contracts in place at December 31, 2016 including Newbuilds, seven are scheduled to expire before December 31, 2017, six are scheduled to expire during 2018, with a further 12 contracts scheduled to expire at times subsequent to December 31, 2018.

The Company seeks to secure long-term agreements providing enhanced stability and deeper customer relationships rather than the highest possible dayrates on a shorter term basis. This has allowed us to achieve relatively high levels of fleet utilization compared to our competitors. At December 31, 2016, the average remaining contract term was approximately 24 months per rig, with the shortest remaining contract term being approximately one month and the longest remaining contract term being five years. Typically NOC contracts are for longer terms when compared to contracts with IOCs or independent exploration and production companies, although in certain countries annual government budget approval cycles may limit the tenor of these contracts.

A focus on providing services to customers engaged in development and workover activity on producing assets also enhances contract term length. Such brownfield development provides more predictable levels of activity, as opposed to greenfield exploration which tends to be shorter term and more closely linked to prevailing commodity prices and success of exploration activities.

Generally, contracts for drilling services specify a basic rate of compensation computed on a dayrate basis with monthly invoicing and between 30 to 60 day payment terms. Reductions to the basic dayrate are triggered when operations are interrupted due to equipment failure, field moves, adverse weather and other factors beyond the Company's control. Some contracts also provide for price adjustments tied to material changes in specific costs. Such reductions in basic dayrates, inactive periods between contracts and stacking of rigs will result in an adverse effect on revenues and operating profits. An over-supply of drilling rigs or lower demand for drilling rigs in markets in which we operate may adversely affect our ability to acquire contracts at favorable dayrates in those areas. The dayrates and new contracts (including extensions) reflected in recent contract activity are impacted by the current overall industry activity level and rig supply and demand. During periods of weak demand and reduced day rates, we have historically entered into contracts at lower day rates in order to keep our rigs working.

We may receive additional compensation or reimbursement for mechanical or structural alterations to a rig necessary to meet customer specifications and for mobilization costs necessary to relocate the vessel for contractual operations. The extent to which individual customers will pay for these costs is driven by negotiation of the individual contracts. Factors which influence these negotiated payments include the duration of the potential contract, the dayrate, local market conditions and other factors.

Customer contracts are subject to cancellation, suspension and delays for a variety of reasons, including some beyond our control. Dayrates set forth in this Filing are estimates based upon the full contract operating dayrate. However, actual dayrates earned over the course of any given contract are lower and may be substantially lower, due to factors discussed above.

Certain customer contracts are cancellable upon payment of an early termination fee. These contracts may be terminated at the customers' convenience and sole option. The amount of these payments varies from contract to contract, and typically range from 50 to 100% of the dayrate multiplied by the number of firm contract days remaining on the contract. However, in certain contracts the customers may also have an early termination right by serving due advanced notice as stipulated in the contract, and typically in such instances the early termination fee could be lower. In certain cases a portion of the termination payments can be recouped by the customer upon commencement of a subsequent drilling contract with a different operator. Customer contracts also customarily provide for either automatic termination or termination at the option of the customer for cause, typically without the payment of any termination fee. These options are available under pre-defined circumstances such as our non-performance or material breach to the contractual terms and conditions. Triggering events for early termination with cause include downtime, impaired performance due to equipment or operational issues, safety performance and sustained periods of downtime related to force majeure events. In a limited number of contracts, the customer may cancel the contract without cause or payment of an early termination fee by serving a certain period of notice.

The Company's drilling contracts provide for varying levels of indemnification for both us and customers. Management believes the terms of such indemnification are standard for the industry. In general, the parties assume liability for their respective personnel and property. However, in certain cases, we may retain risk for damage to customer property and other third-party property on our rigs. The Company's customers typically assume responsibility for, and indemnify the Company from, any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages, arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well. However, the Company may retain liability for third-party damages resulting from pollution or contamination, subject to negotiated limits. We generally indemnify customers for pollution that originate from our rigs and which are within our control (e.g., diesel fuel or other fluids stored onboard for the use of the rig). However, all contracts are individually negotiated, and the degrees of indemnification and/or risk retention discussed above vary from contract to contract, based on negotiation. Local jurisdiction regulations may require us to post surety bonds, letters of credit and parent company guarantees for contract performance.

The Company's customer contracts and operations are subject to a number of additional risks and uncertainties; readers of this Filing should carefully review the discussion contained in Item 1A. "Risk Factors".

Insurance

The Company's operations are subject to the usual hazards associated with the drilling of offshore oil and natural gas wells such as blowouts, explosions and fires. In addition, drilling rigs and their associated equipment are subject to various risks particular to the industry that we seek to mitigate by maintaining insurance. These risks include, but are not limited to: leg damage to jackup rigs during positioning, capsizing, grounding, collision and damage from severe weather conditions. The Company maintains an amount of insurance coverage which management believes is common in the industry and is sufficient to adequately mitigate the principal risks to our business, assets and employees. This coverage includes, but is not limited to: general business liability, hull and machinery, cargo, and casualty and liability (including excess liability). The drilling rig fleet is insured for its estimated fair market value and we periodically evaluate risk exposures, insurance limits and self-insured retentions. As of December 31, 2016, the insured value of the Company's drilling rig fleet was $1.6 billion, which includes the newbuild rig which commenced its drilling contract on December 1, 2016.

As a condition of doing business with some of our customers, they may require minimum levels of insurance. The Company has had sufficient levels of insurance in place to satisfy such requirements and expects to maintain such required levels in the future. In common with most other companies in the industry, we do not carry business interruption insurance to compensate for loss of revenue in the event of loss or damage to our rigs.

The above description of our insurance program and the indemnification provisions of our drilling contracts is only a summary as of the time of preparation of this report, and is general in nature. Our insurance policies typically consist of twelve-month policy periods, and the next renewal date for a substantial portion of our insurance program is scheduled for November 2017.

Our insurance policies and contractual rights to indemnity may not adequately cover our losses and liabilities in all cases. For additional information, see Item 1A. "Risk Factors".

Maintenance and Certifications

The International Maritime Organization ("IMO") classifies mobile offshore drilling rigs pursuant to its Code for the Construction and Equipment for Mobile Offshore Drilling Units. The maintenance and inspection regime, which each of the Company's rigs is subject to, is governed by this Code. Rigs are subject to periodic testing, with the frequency of inspection dependent on equipment classification. Each of our rigs is subject to a major inspection every five years pursuant to the Special Periodic Survey requirements. This process typically takes three to six weeks and is scheduled to be undertaken between customer contracts to minimize downtime. The rigs are also subject to UWILDs, intermediate surveys and annual inspections between each Special Periodic Survey. These requirements, along with a robust preventative maintenance program, enhanced operational performance and the Company's HSE record have successfully minimized unplanned out of service time. The entire fleet is certified according to international safety standards under the International Safety Management Code and is certified by the American Bureau of Shipping Classification Society, enabling universal recognition of our equipment as being qualified for international operations.

The Company's organizational objective is to maintain its assets to provide optimal operating performance while minimizing out of service time and total capital expenditure.

Employees

At December 31, 2016, the Company had approximately 1,950 employees, with approximately 1,650 working offshore and 300 working onshore. In addition, we engaged approximately 900 qualified contractors, of which approximately 830 work offshore and 70 onshore. These employees and contractors have extensive technical, operational and management experience in the jackup segment of the offshore drilling industry. The Company expects to continue to utilize the services of independent contractors to perform various field and other services from time to time.

Approximately 13% of our employees and contractors are shore-based, with the largest concentration employed in facilities that support our activities in the various countries in which we operate, and the remainder employed at the Company's headquarters in Dubai,. These employees and contractors are engaged in operations, commercial and marketing, technical and construction, finance, human resources, procurement, HSE and information technology providing support to fleet operations. The remaining 87% comprise offshore rig crew-members who carry out day-to-day drilling operations.

The Company's offshore crews include supervisors as well as trained and competent technical specialists in the areas of drilling operations, safety, maintenance and marine support. Offshore crews typically work rotation schedules which vary according to jurisdiction and local practice with periods ranging from two weeks on / two weeks off up to four weeks on / four weeks off.

Our management team has a demonstrated commitment to training personnel according to best industry practice in both operational and HSE areas.

The following table presents the Company’s employees and contractors by function as of December 31, 2016.

	Company employees	Contractors	Total
Rig Based	1,625	819	2,444
Shore Based	194	42	236
Corporate	112	26	138
Total	1,931	887	2,818

Employees in some of the countries in which the Company operates are represented by trade unions and arrangements may be made through collective bargaining agreements. Management considers relations with trade unions and other employee representative groups to be good.

Our strategy is to employ national employees and contractors wherever possible in markets in which we operate. The following table shows the employee mix in certain of our key markets at December 31, 2016.

	National employees including contractors	Expatriate employees
Egypt	100%	-
India	97%	3%
Nigeria	97%	3%
All other regions	68%	32%

Health, Safety and Environment

The Company places a high priority on managing the risks inherent in the offshore drilling industry and is committed to compliance with the highest national and international HSE standards. The Company utilizes an integrated management system covering the quality, health, safety and environmental principles and objectives of its business, which is implemented throughout all offshore and onshore operations. This management system aims to provide innovative and sustainable solutions to monitor the Company’s HSE performance and continuously improve the necessary safeguards to protect its employees, assets, service providers and customers and to minimize its impact on the environment.

Health and Safety

Management believes the Company to be an industry leader in HSE due to a commitment to develop, promote and sustain a culture which operates in a manner true to our slogan “protect yourself, protect your team, protect your asset”. Senior management strives to provide strong, demonstrable leadership and commitment to HSE. Participation in specific meetings with staff and contractors, joint management inspection visits and regular HSE audits all encourage a strong focus on HSE in Company workplaces.

We have implemented comprehensive HSE processes, including Medical Evacuation Response Plans, Emergency Response Plans, a Corporate Operational Support Plan and a major emergency management and safety leadership training program (based on a focused training matrix). The Company believes it has put in place HSE policies, processes and systems which are in line with industry best practice. The Company tracks health, safety and environment performance and issues on a monthly basis by way of a monthly HSE report, tracking, trending and investigations which are stored in a safety data base designed by Shelf Drilling named “HSE dashboard”.

Management believes the Company’s HSE programs are reflective of best practices in the industry. During the year ended December 31, 2016, we had a total recordable incident rate of 0.25.

SDL, on behalf of all the entities in the Shelf Drilling group, is a member of the International Association of Drilling Contractors (“IADC”) and participates in its Incident Statistics Program.

Environment

The Company's operations are subject to numerous comprehensive environmental laws and regulations in the form of international conventions and treaties, national, state and local laws and various multi-jurisdictional regulations in force where our rigs operate or are registered.

These requirements include, but are not limited to, the International Convention for the Prevention of Pollution from Ships (''MARPOL''), the International Convention on Civil Liability for Oil Pollution Damage of 1969 (the ''CLC''), the International Convention on Civil Liability for Bunker Oil Pollution Damage (''Bunker Convention'') and various international, national and local laws and regulations that impose compliance obligations and liability related to the use, storage, treatment, disposal and release of petroleum products and hazardous substances. These laws govern the discharge of materials into the environment or otherwise relate to environmental protection. In certain circumstances, these laws may impose strict liability, rendering the Company liable for environmental and natural resource damages without regard to negligence or fault on its part. For example, the United Nations' IMO has adopted MARPOL, Annex VI which regulates harmful air emissions from ships, and which is applicable to offshore drilling rigs as well. Amendments to the Annex VI regulations which entered into force on July 1, 2010, require a progressive reduction of sulfur oxide levels in heavy bunker fuels and create more stringent nitrogen oxide emissions standards for marine engines in the future. The Company may incur costs to comply with these revised standards. Drilling rigs must comply with MARPOL limits on sulfur oxide and nitrogen oxide emissions, chlorofluorocarbons, and the discharge of other air pollutants, except that the MARPOL limits do not apply to emissions that are directly related to drilling, production, or processing activities. Our drilling rigs are subject not only to MARPOL regulation of air emissions, but also to the Bunker Convention's strict liability for pollution damage caused by discharges of bunker fuel in jurisdictional waters of ratifying states. Management believes that all of the Company's drilling rigs are compliant in all material respects with all environmental, health and safety regulations to which they are subject.

The Company's operations are subject to various other international conventions, laws and regulations in various countries, including laws and regulations relating to the importation and operation of drilling rigs and equipment, currency conversions and repatriation, oil and natural gas exploration and development, environmental protection, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of drilling rigs and other equipment.

While customers use our drilling rigs to support activities that are inherently hazardous, the Company's liability for environmental damage resulting from an incident involving its rigs is limited. Customer contracts typically contain ''knock-for-knock'' provisions which restrict liability to damage to rigs and personnel.

Item 1A. Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could affect our business, operating results and financial condition, as well as affect an investment in our company.

Risks Related to the Business

Our business depends on the level of activity in the offshore drilling industry which is significantly affected by the volatile nature of the oil and natural gas exploration and production industry and will be adversely affected by a further decline in oil and gas prices.

The level of activity of the offshore oil and natural gas industry is cyclical, volatile and impacted by oil and natural gas prices. Sustained periods of low oil and natural gas prices typically result in reduced exploration and drilling because oil and natural gas companies' capital expenditure budgets are dependent on cash flow from such activities and are therefore sensitive to changes in energy prices. A decline in the activity levels of the offshore oil and natural gas industry may have a material adverse effect on the business, financial condition and results of our operations.

Oil and natural gas prices are unpredictable and are affected by numerous factors beyond our control, including the following:

- worldwide production and demand for oil and natural gas, which are impacted, amongst other factors, by changes in the rate of economic growth in the global economy;
- worldwide financial instability or recessions;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- expectations regarding future energy prices;
- advances in exploration, development and production technologies;

- the discovery rate of new oil and gas reserves;
- increased supply of oil and gas resulting from growing onshore hydraulic fracturing activity and shale development;
- available pipeline and other oil and gas transportation capacity;
- technical advances affecting energy consumption and in the development and exploitation of alternative fuels;
- the ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain production levels and pricing;
- the level of production in non-OPEC countries;
- local and international political, economic and weather conditions;
- domestic and foreign tax laws, regulations and policies;
- merger and divestiture activity among oil and gas producers;
- the availability of, and access to, suitable locations from which our customers can explore and produce hydrocarbons;
- the policies and regulations of various governments regarding exploration and development of their oil and natural gas reserves or speculation regarding future laws or regulations; and
- the worldwide political and military environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East or other geographic areas or further acts of terrorism in the regions in which we operate, or elsewhere.

Our operations are primarily focused on development and workover activities on producing oil and gas assets in the shallow water offshore zones. Management believes these sectors are typically less affected by lower oil and natural gas prices than activities focused on exploration of new oil and gas assets. In recent years, oil and natural gas prices have fallen therefore negatively affecting our business in the shallow water offshore drilling sector. We cannot predict the future level of demand for our services or future conditions of the oil and natural gas industry. Any further decrease in exploration, development or production drilling expenditures by oil and natural gas companies could continue to have an adverse effect on our business, financial condition and results of operations.

The industry has been historically competitive, cyclical and subject to price competition. If we are unable to compete successfully with our competitors, our profitability may be reduced.

The shallow-water drilling business in which we operate is extremely competitive, and contracts have traditionally been awarded on a competitive bid basis. Price competition is frequently a major factor in determining a contract award. Customers may also consider unit availability and location; operational and safety performance records; and condition and suitability of equipment. Competition for offshore rigs is frequently on a global basis, as drilling rigs are mobile and may be moved from areas of low utilization and dayrates to areas of greater activity and corresponding higher dayrates. Costs connected with relocating drilling rigs for these purposes are sometimes substantial. If we are not able to compete successfully with our competitors, our revenues and profitability may suffer.

The offshore contract drilling industry, historically, has been cyclical with periods of high demand, limited supply and high dayrates alternating with periods of low demand, excess supply and low dayrates. Competitors may move drilling rigs from region to region in response to changes in demand, which could result in an excess supply of rigs in the markets in which we operate. Periods of low demand and excess supply intensify competition in the industry and may result in some drilling rigs being stacked or earning substantially low dayrates for long periods of time. There can be no assurance when such periods will end. In addition, the offshore drilling industry is influenced by additional factors including:

- the availability of competing offshore drilling rigs;
- the level of costs for associated offshore oil and natural gas and construction services;
- oil and natural gas transportation costs;
- the discovery of new oil and natural gas reserves;
- the economics of non-conventional hydrocarbons;
- the political and military environment of oil and natural gas reserve jurisdictions; and
- regulatory restrictions on offshore drilling.

Any of these factors, together with prolonged periods of low utilization and dayrates, as well as extended periods when rigs are stacked, could reduce demand for the Company's services and materially adversely affect our business, financial condition or results of operations.

Our future business performance depends on our ability to secure new contracts for our fleet of rigs and/or on the renewal of our existing contracts by our customers.

Our ability to win tenders for new contracts, as well as contract renewals where we are the incumbent rig provider, is affected by a number of factors beyond our control, such as market conditions, rig specifications, safety record requirements, competition and governmental approvals required by customers. If we are not selected or if the contracts we enter into are delayed, work flow may be interrupted and our business, financial condition or results of operations may be materially adversely affected.

If an existing customer decides not to renew its contract, we must then secure a new contract for that rig. Based on customer contracts in place as of December 31, 2016, seven are scheduled to expire before December 31, 2017, six are scheduled to expire during 2018, with a further 12 contracts scheduled to expire at times subsequent to December 31, 2018. While we actively market our rigs' availability prior to the expiry of a contract, there can be no assurance that we will be able to renew or extend existing contracts or secure new arrangements before the original contract lapses. Re-contracting a rig may involve participation in either a direct renegotiation with the customer or in a new tender process, the length and complexity of which could lead to a rig being stacked and/or having to enter into a new contract at lower dayrates, shorter terms or in other geographical areas and could materially adversely affect our financial condition and results of operations.

Our future contracted revenue, or backlog, for the fleet of drilling rigs may not be ultimately realized.

The contract backlog relating to our drilling rigs was approximately $1.7 billion as of December 31, 2016. The amount of contract backlog does not necessarily indicate future earnings, and the backlog may be adjusted up or down depending on award of new contracts or extensions or the exercise by the customer of extension options, early cancellation of existing contracts (for which we may not be entitled to compensation, as in the case of termination resulting from force majeure), renegotiation of contract dayrates, failure by customers to extend existing contracts or to pay amounts owed or the unavailability of equipment to fulfill a contract due to repairs, maintenance or inspections.

The occurrence of any of these events could impact the realization of our contract backlog therefore resulting in a material adverse effect on our business, financial condition and results of operations. Due to events beyond our control, we can provide no assurance that we will be able to perform under these contracts nor provide assurance that our customers will be able to or willing to fulfill their contractual commitments to us or that they will not seek to renegotiate or repudiate their contracts, especially during the current industry downturn.

We will continue to experience reduced profitability if our customers reduce activity levels, terminate or continue to seek to renegotiate contracts or if we experience downtime, operational difficulties or safety-related issues.

Our contracts may be cancellable at the option of the customer upon payment of a termination fee, which may not fully compensate us for the loss of the contract. We also have a small number of contracts that may be cancelled at the option of the customer without early termination fee payment and by serving a notice period. In addition, we could be required to make termination payments if contracts are terminated due to downtime, operational problems, safety- related issues or failure to deliver. Early termination of a contract may result in a rig being stacked for an extended period of time. The likelihood of a customer seeking to terminate a contract is increased during periods of market weakness. If customers cancel, suspend or require us to renegotiate significant contracts, and we are unable to secure new contracts on substantially similar terms, our revenue and profitability would be materially reduced, which could have a material adverse effect on our business, financial condition and results of operations.

During the current depressed market conditions, some of our customers have renegotiated the terms of their existing drilling contracts which has resulted in reduced profitability.

We rely on a relatively small number of customers for a substantial portion of our future contracted revenue.

Our customer base includes a small number of major and independent oil and gas companies as well as government-owned oil companies The contract drilling business is subject to the usual risks associated with having a limited number of customers. Our top four customers, who accounted for 90% of contract backlog as at December 31, 2016, also accounted for 72% of revenues for the year ended December 31, 2016. Our business, financial condition and results of operations could be materially and adversely affected if any of these customers were to suspend or withdraw their approval for us to provide services for them. Our growth is also closely connected to the growth of our customers and our results may be impacted if certain key customers were to significantly reduce their growth strategy. Furthermore, if any of our major customers failed to compensate us for our services, terminated contracts, failed to renew existing contracts or refuse to enter into new contracts with us, or if a customer were unable to perform due to liquidity or solvency issues, and similar contracts with new customers were not forthcoming, our business, financial condition and results of operations would be materially and adversely affected.

Upgrade, refurbishment and repair projects are subject to risks, including delays and cost overruns, which could have an adverse impact on our available cash resources or results of operations.

The Company incurs upgrade, refurbishment and repair expenditures for its fleet from time to time, including when upgrades are required by industry standards and/or by law. Such expenditures are also necessary in response to requests by customers, inspections, regulatory or certifying authorities or when a rig is damaged. We also regularly make certain upgrades or modifications to our drilling rigs to meet customer or contract specific requirements. Upgrade, refurbishment and repair projects are subject to project management execution risks of delay or cost overruns, including costs or delays resulting from the following:

- unexpectedly long delivery times for, or shortages of, key equipment, parts and materials;
- shortages of skilled labor and other shipyard personnel necessary to perform the work;
- scope creep, unforeseen increases in the cost of equipment, labor and raw materials, particularly steel;
- unforeseen design and engineering problems;
- latent damages to or deterioration of hull, equipment and machinery in excess of engineering estimates and assumptions;
- unanticipated actual or purported change orders;
- HSE incidents;
- failure or delay of third-party service providers;
- disputes with shipyards and suppliers;
- delays and unexpected costs of incorporating parts and materials needed for the completion of projects;
- changes to the customers' specifications;
- failure or delay in obtaining acceptance of the rig from a customer;
- financial or other difficulties at shipyards;
- adverse weather conditions; and
- inability or delay in obtaining flag-state, classification society, certificate of inspection, or regulatory approvals.

Significant cost overruns or delays would adversely affect our business, financial condition and results of operations. Additionally, capital expenditures and deferred costs for rig upgrades and refurbishment projects, including any planned refurbishment and upgrade of its rigs, could exceed our planned capital expenditures. Failure to complete an upgrade, refurbishment or repair project on time may, in some circumstances, result in the delay, renegotiation or cancellation of a drilling contract and could put at risk planned arrangements to commence operations on schedule. We could also be exposed to contractual penalties for failure to complete an upgrade, refurbishment or repair project and commence operations in a timely manner. Our rigs undergoing upgrade, refurbishment or repair generally do not earn a dayrate during the period they are out of service. Failure by the Company to minimize lost dayrates resulting from the immobilization of its rigs may adversely impact our business, financial condition and results of operations.

Supplier capacity constraints or shortages in parts or equipment, supplier production disruptions, supplier quality and sourcing issues or price increases could increase our operating costs, decrease our revenues and adversely impact our operations.

Our reliance on third-party suppliers, manufacturers and service providers to secure equipment used in our drilling operations exposes us to volatility in the quality, price and availability of such items. Certain specialized parts and equipment we use in our operations may be available only from a single or small number of suppliers. A disruption in the deliveries from such third-party suppliers, capacity constraints, production disruptions, price increases, defects or quality-control issues, recalls or other decreased availability or servicing of parts and equipment could adversely affect our ability to meet our commitments to customers, adversely impact our operations and revenues by resulting in uncompensated downtime, reduced day rates or the cancellation or termination of contracts, or increase our operating costs.

An over-supply of new jackup rigs may lead to a further reduction in dayrates and therefore may materially impact our profitability.

Prior to the recent industry downturn, industry participants have increased the supply of drilling rigs by ordering construction of new drilling rigs. This could result in an oversupply of drilling rigs and cause a subsequent decline in utilization and dayrates when the new drilling rigs enter the market. To the extent that jackup drilling rigs currently under construction have not been contracted for future work, there may be increased price competition as those rigs enter the market, leading to a reduction in dayrates. An over-supply of jackup rigs may also result in certain customers preferring newer, higher specification rigs over older rigs which could lead to a further reduction of our utilizations and dayrates. As a result our business, financial condition and results of operations would be materially adversely affected.

Our rigs are on average 34 years old and some customers may prefer newer and/or higher specification rigs.

A number of our competitors’ jackup rigs are newer and/or have higher specifications and capabilities than some of those in our fleet. While our rigs are maintained to high standards and considered by the management to be “fit for purpose” for their intended requirements, certain customers may prefer newer and/or higher specification rigs. Any such trend may impact our utilization and dayrates, which could have a material adverse effect on our business, financial condition and results of operations.

There may be further asset impairments as a result of future declines in dayrates and utilization for shallow water drilling rigs.

We evaluate our property and equipment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss on property and equipment exists when the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

The offshore drilling industry historically has been highly cyclical, and it is not unusual for rigs to be unutilized or underutilized for significant periods of time and subsequently resume full or near full utilization when business cycles change. Likewise, during periods of supply and demand imbalance, rigs are frequently contracted at or near cash break-even rates for extended periods of time until day rates increase when the supply/demand balance is restored. However, if the global economy was to deteriorate and/or the offshore drilling industry was to incur a significant prolonged downturn, additional impairment charges may occur with respect to specific individual rigs or rigs in a certain geographic location.

At December 31, 2016, we recorded a non-cash impairment loss of $47.1 million. See *Note 8 - Property and Equipment* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

We are exposed to the credit risks of our key customers and certain other third parties.

We are subject to risks of loss resulting from non-payment or non-performance by third parties. Although we monitor and manage credit risks, some of our customers and other parties may be highly leveraged and subject to their own operating and regulatory risks. During more challenging market environments, we are subject to an increased risk of customers seeking to repudiate contracts. Our customers’ ability to perform their contractual obligations may also be adversely affected by restricted credit markets and economic downturns. If one or several key customers or other parties were to default on their obligations to us, our business, financial condition and results of operations could be adversely affected.

We recorded a provision for doubtful accounts of $7.4 million for the year ended December 31, 2016 related to the uncertainty of collectability for specifically identified accounts receivable.

There may be limits to our ability to mobilize drilling rigs between geographic areas, and the duration, risks and associated costs of such mobilizations may be material to our business.

The offshore contract drilling market is generally a global market as drilling rigs may be moved from one area to another. However, the ability to mobilize drilling rigs can be impacted by several factors including, but not limited to, governmental regulation and customs practices, the significant costs and risk of damage related to moving a drilling rig, availability of tugs and dry tow vessels to move the rigs, weather, political instability, civil unrest, military actions and the technical capability of the drilling rigs to relocate and operate in various environments. Additionally, while a jackup rig is being mobilized from one geographic market to another, we may not be paid for the time that the jackup rig is out of service. We may relocate a rig to another geographic market without a customer contract, which could result in costs not reimbursable by future customers. We also operate in regions impacted by monsoon seasons, which may create delays resulting in lower utilization rates and lost dayrate revenue. As such, mobilization and rig relocating activities could have a material adverse effect on our business, financial condition and results of operations.

Our business involves numerous operating hazards; insurance and contractual indemnity rights may not be adequate to cover any losses resulting therefrom.

Our operations are subject to the usual hazards inherent in the drilling, completion and operation of oil and natural gas wells. These hazards include, but are not limited to blowouts, reservoir damage, punch through, loss of production, loss of control of the well, abnormal drilling conditions, mechanical or technological failures, craterings, fires and pollution and failure of our employees to comply with internal HSE guidelines. The occurrence of these events may result in the suspension of drilling or production operations, fines or penalties, claims or investigations by the operator, regulatory bodies and others affected by such events, severe damage or destruction of property and equipment involved, injury or death to rig personnel, environmental damage and increased insurance costs. We may also be subject to personal injury and other claims of drilling rig personnel as a result of our drilling operations. Operations also may be suspended because of machinery breakdowns, abnormal operating conditions, failure of subcontractors to perform and personnel shortages.

In addition, our operations are subject to perils peculiar to marine operations including capsizing, grounding, collision, sinking and loss or damage from severe weather. Severe weather could have a material adverse effect on our operations, damaging our rigs from high winds, turbulent seas, or unstable sea bottom conditions. Such occurrences could potentially cause us to curtail operations for significant periods of time while repairs are effected.

Damage to the environment could result from our operations, particularly through blowouts, oil spillage or extensive uncontrolled fires. We may also be subject to fines, penalties resulting from property, environmental, natural resource and other damage claims by governments, oil and natural gas companies and other businesses operating offshore and in coastal areas, including claims by individuals living in or around coastal areas.

As is customary in the offshore drilling industry, the risks of our operations are covered partially by insurance and partially by contractual indemnities from our customers. However, insurance policies may not adequately cover losses and customers may not be financially able to indemnify us against all these risks. Also, we may not be able to enforce these indemnities due to legal or judicial factors. Additionally, in some customer contracts we are unable to obtain agreements which would fully indemnify us from such damages and risks. As a result, we may not have insurance coverage or indemnification for all risks. Moreover, pollution and environmental risks generally are not fully insurable. If a significant accident or other event resulting in damage to the drilling rigs, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our business, financial condition and results of operations.

Our insurance coverage may become inadequate to cover losses, more expensive, and may become unavailable in the future.

Our insurance coverage is subject to certain significant deductibles and does not cover all types of losses and, in some situations, may not provide full coverage for losses or liabilities resulting from our operations. In common with other companies in the industry, we do not maintain business interruption insurance. We may experience increased costs for available insurance coverage, which may impose higher deductibles and limit maximum aggregated recoveries, including for hurricane or cyclone-related windstorm damage or loss. Insurance costs may increase in the event of ongoing patterns of adverse changes in weather or climate. Although we believe our insurance is adequate, our policies and contractual indemnity rights may not adequately cover all losses or may have exclusions of coverage for certain losses. We do not have insurance coverage or rights to indemnity for all risks. Moreover, we may not be able to maintain adequate insurance or obtain insurance coverage for certain risks in the future at rates we consider reasonable. These insurance related risks could adversely affect our business, financial condition and results of operations.

If we are unable to acquire additional rigs on economically acceptable terms, or at all, our future growth will be limited, and any such acquisitions we may make could have an adverse effect on our results of operations.

Part of our strategy to grow the business is dependent on our ability to acquire additional rigs to generate further revenues. The consummation and timing of any future acquisitions will depend upon, among other things, the availability of attractive targets in the marketplace, our ability to negotiate acceptable purchase agreements and our ability to obtain financing on acceptable terms. These factors provide no assurance that we will be able to consummate any future acquisition and may limit our future growth.

Further, any acquisitions of rigs could expose us to, among other things, the risk of undetected defects, incorrect assumptions related to revenue in our evaluation and unforeseen consequences or other external events beyond our control.

If we were to reactivate speculatively any of our stacked rigs or commit speculatively to construct newbuild rigs, we could be exposed to a number of risks which could adversely affect our financial position, results of operations and cash flows.

If we were to reactivate speculatively any of the rigs which are currently stacked or any other rigs which may be stacked in the future, or to speculatively enter into construction contracts for newbuild rigs, we could be exposed to a number of risks. For example, the reactivation process is subject to project management and execution risks and newbuild projects are subject to the risks discussed below. In addition, if we were to reactivate a stacked rig or order a newbuild rig absent a firm customer contract for the rig, no assurance can be given that we would be able to negotiate a customer contract in a timely manner and on economically attractive terms. Failure to execute the reactivation project on time and on budget, as well as a failure to contract such rig or a newbuild rig on acceptable terms or in a timely manner could adversely affect our financial position, results of operations and cash flows.

Our ability to keep pace with technological developments in our markets and to make adequate capital expenditures in response to higher specification rigs being deployed within the industry.

The market for our services is characterized by technological developments which result in improvements in the functionality and performance of rigs and equipment. Customers may demand the services of newer, higher specification drilling rigs, and may in the future impose restrictions on the maximum age of contracted drilling rigs. To the extent that we are unable to negotiate agreements for customer reimbursement for the cost of increasing the specification of our drilling rigs, we could be incurring higher capital expenditures than planned. Customer demand for newer, higher specification rigs might also result in a bifurcation of the drilling fleet for jackup rigs, with newer rigs operating at higher overall utilization rates and dayrates. As the average age of our rigs is approximately 34 years, we may be required to increase capital expenditure to maintain and improve existing rigs and equipment and/or purchase and construct newer, higher specification drilling rigs to meet the increasingly sophisticated needs of customers. While management believes the "fit for purpose" nature of our fleet is well suited to customers' requirements and the requirements of the markets in which we operate, our future success and profitability will depend, in part, upon our ability to keep pace with technological developments. If, in response to technological developments or changes in standards in the industry, we are not successful in acquiring new equipment or upgrading existing equipment in a timely and cost-effective manner, we could lose business and profits. In addition, current competitors or new market entrants may develop new technologies, services or standards that could render some of our services or equipment obsolete, which could have a material adverse effect on our business, financial condition and results of operations.

Newbuild projects are subject to various risks which could cause delays or cost overruns and have an adverse impact on our results of operations.

Our strategy to increase the size of our fleet could include the construction of newbuild rigs. We have one new build rig under construction as of December 31, 2016. We have secured a drilling contract for this rig, which will commence upon completion of construction and final customer acceptance requirements. Construction of newbuild rigs are subject to a number of risks, including:

- unexpectedly long delivery times for, or shortages of, key equipment, parts and materials;
- unforeseen design and engineering problems leading to delays;
- labor disputes and work stoppages at the shipyard;
- HSE accidents/incidents or other safety hazards;
- disputes with the constructing shipyard or other suppliers;
- last minute changes to the customer's specifications;
- failure or delay in obtaining acceptance of the rig by our customer;
- financial or other difficulties at shipyards;
- adverse weather conditions or any other force majeure events;
- inability or delay in obtaining flag-state, classification society, or regulatory approvals or permits; and
- mobilization from shipyard to contract operating site.

Failure to complete a newbuild project on time may result in the delay, renegotiation or cancellation of an existing drilling contract and could put at risk the planned arrangements to commence operations on schedule. Further, significant delays could have a negative impact on our reputation and customer relationships. We also could be exposed to contractual penalties for failure to complete the project and commence operations in a timely manner, all of which would adversely affect our business, financial condition and results of operations.

The market value of our drilling rigs and of any rigs we acquire in the future may decrease, which could cause us to incur losses if we decide to sell them following a decline in our market values.

The fair market value of any drilling rigs that we own may increase or decrease depending on a number of factors, including:

- general economic and market conditions affecting the offshore contract drilling industry, including competition from other offshore contract drilling companies;
- types, sizes and ages of drilling rigs, including specifications and condition;
- liquidity of the market for drilling rigs;

- supply and demand for drilling rigs;
- costs of newly built rigs;
- prevailing level of drilling services contract dayrates;
- governmental or other regulations; and
- technological advances.

If we sell any drilling rig at a time when prices for drilling rigs have fallen, such a sale may result in a loss. Such a loss could materially and adversely affect our business, financial condition or results of operations.

Our labor costs and the operating restrictions that apply to us could increase as a result of collective bargaining negotiations and changes in labor laws and regulations.

Some of our employees in Egypt and Nigeria are represented by unions and may, from time to time, work under collective bargaining agreements. In addition, some of our contracted labor works under collective bargaining agreements. As part of the legal obligations in some of these agreements, we are required to contribute certain amounts to retirement funds and are restricted in our ability to dismiss employees. In addition, where our employees are represented by unions, we may be required to negotiate wages. Negotiations with unions relating to collective bargaining agreements and other labor related matters could result in higher personnel costs, other increased costs or increased operating restrictions, or even labor stoppages, strikes or slowdowns that could adversely affect our business, financial condition and results of operations.

We are dependent on key employees including senior management team, and the business could be negatively impacted if we are unable to attract and retain personnel necessary for its success.

We are highly dependent on executive management. Our directors and senior management possess marketing, engineering, project management, financial and administrative skills that are important to the operation of our business. The loss or an extended interruption in the services of our senior personnel, or the inability to attract or develop a new generation of senior management, could have an adverse effect on our business, financial condition and results of operations. We do not maintain key man life insurance.

The availability and retention of skilled personnel and increases in labor costs.

We require highly skilled personnel to operate and provide technical services and support in our operations. Many of our customers require specific minimum levels of experience and technical qualification for certain positions on rigs which they contract. In periods of high utilization and demand for drilling services, it is more difficult and costly to recruit and retain qualified employees, especially in foreign countries that require a certain percentage of national employees. This limited availability of qualified personnel coupled with local regulations focusing on crew composition could impact our ability to fully staff and operate our rigs and also could increase our future operating expenses, with a resulting reduction in net income.

Our interests in certain of our subsidiaries are subject to arrangements with local partners and the loss of their support could have a material adverse effect on our business.

Several countries in which we operate require foreign entities to comply with certain laws and regulations concerning minimum local content requirements. As a result, we may be required to enter into legally binding arrangements with local entities in those jurisdictions in order to conduct operations. In Indonesia, Malaysia, India, Nigeria and the UAE, we maintain a series of contractual and legal agreements with local partners and/or agents, whom management believes are an integral part of the successful operation of our business in these markets. If we were to lose the support of these local participants and were unable to find suitable replacements, local regulators may curtail or terminate our operations. In addition, the success of these local relationships depends on the reputation, creditworthiness, stability and continuity of the local businesses with which we are required to operate. If any of these local partners were to become subject to bankruptcy/insolvency proceeding or adverse regulatory or judicial proceedings, or lose the ability to carry out the operations for any other reason, then our business, financial condition and results of operations could be adversely affected.

We are exposed to market risks, which could create the inability to secure financing on terms which are acceptable to management.

We are exposed to market risks from changes in interest rates under our obligations under the Revolving Credit Agreement and obligations under sale and leaseback. Interest rates under theses financing arrangements are determined with reference to a specified margin above LIBOR. If market interest rates increase, this could have an adverse impact on our results of operations and cashflows. We have not entered into any hedging arrangements with respect to our interest rate exposure.

Our overall debt level and/or market conditions and also failure to make payments of interest on our outstanding indebtedness on a timely basis would likely result in a reduction of long-term corporate credit ratings. These downgrades in our corporate credit ratings could impact our ability to issue additional debt by raising the cost of issuing new debt. As a consequence, we may not be able to issue additional debt in reasonable amounts and terms. These could potentially limit our ability to pursue business opportunities.

Our international operations in the offshore drilling sector involve additional risks, which could adversely affect our business.

We operate in various regions throughout the world and as a result we may be exposed to political and other uncertainties, including risks of:

- terrorist acts, armed hostilities, war and civil disturbances;

- acts of piracy, which have historically affected ocean-going rigs, trading in regions of the world such as the South China Sea, Strait of Malacca, off the coast of West Africa and in the Gulf of Aden off the coast of Somalia and which have increased significantly in frequency since 2008;

- significant governmental influence over many aspects of local economies;

- repudiation, nullification, modification or renegotiation of contracts;

- limitations on insurance coverage, such as war risk coverage, in certain areas;

- political unrest or revolutions;

- foreign and United States monetary policy and foreign currency fluctuations and devaluations;

- the inability to repatriate income or capital;

- complications associated with repairing and replacing equipment in remote locations;

- import-export quotas, wage and price controls and imposition of trade barriers;

- regulatory or financial requirements to comply with foreign bureaucratic actions;

- changing taxation policies, including confiscatory taxation;

- other forms of government regulation and economic conditions that are beyond its control;

- corruption;

- natural disasters;

- public health threats; and

- claims by employees, third parties or customers.

In addition, international contract drilling operations are subject to various laws and regulations of the countries in which we operate, including laws and regulations relating to:

- the equipping and operation of drilling rigs;

- repatriation of foreign earnings;

- oil and natural gas exploration and development;

- taxation of offshore earnings and the earnings of expatriate personnel; and

- use and compensation of local employees and suppliers by foreign contractors.

Some foreign governments favor or effectively require (i) the awarding of drilling contracts to local contractors or to drilling rig owners that are majority-owned by their own citizens, (ii) the use of a local agent or (iii) foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction.

Furthermore, our business operations require authorizations from various national and local government agencies. Obtaining these authorizations can be a complex, time-consuming process, and we cannot guarantee that we will be able to obtain or renew the authorizations required to operate our business in a timely manner or at all. This could result in the suspension or termination of operations or the imposition of material fines, penalties or other liabilities.

These factors may adversely affect our ability to compete in those regions. We are unable to predict future governmental regulations which could adversely affect the international drilling industry. The actions of foreign governments may adversely affect our ability to compete effectively. As such, we may be unable to effectively comply with applicable laws and regulations, including those relating to sanctions and import/export restrictions, which may result in a material adverse effect on our business.

We depend heavily upon the security and reliability of our technology systems and those of our service providers, and such systems are subject to cybersecurity risks and threats.

We depend heavily on technologies, systems and networks that we manage, and others that are managed by our third-party service and equipment providers, to conduct our business and operations. Cybersecurity risks and threats to such systems continue to grow in sophisticated ways that avoid detection and may be difficult to anticipate, prevent or mitigate. If any of our or our service or equipment providers' security systems for protecting against cybersecurity breaches or failures prove to be insufficient, we could be adversely affected by having our business and financial systems compromised, our companies', employees', vendors' or customers' confidential or proprietary information altered, lost or stolen, or our (or our customers') business operations or safety procedures disrupted, degraded or damaged. A breach or failure could also result in injury (financial or otherwise) to people, loss of control of, or damage to, our (or our customers') assets, harm to the environment, reputational damage, breaches of laws or regulations, litigation and other legal liabilities. In addition, we may incur significant costs to prevent, respond to or mitigate cybersecurity risks or events and to defend against any investigations, litigation or other proceedings that may follow such events. Such a failure or breach of our systems could adversely and materially impact our business operations, financial position, results of operations and cash flows.

Any failure to comply with the complex laws and regulations governing international trade, including import, export, economic sanctions and embargoes could adversely affect our operations.

The shipment of equipment and materials required for offshore drilling operations across international borders subjects us to extensive import and export laws and regulations governing our assets, equipment and materials, including those enacted by the United States and/or other countries in which we operate. Moreover, many countries control the export/import and re-export of certain goods, services and technology and may impose related export/import recordkeeping and reporting obligations. Governments also may impose economic sanctions and/or embargoes against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities.

These various jurisdictional laws and regulations regarding export/import controls and economic sanctions are complex, constantly changing, may be unclear in some cases and may be subject to changing interpretations. They may be enacted, amended, enforced or interpreted in a manner that could materially impact our operations. Materials shipments and rig import/export may be delayed and denied for a variety of reasons, some of which are outside our control, and including our failure to comply with existing legal and regulatory regimes. Delays or denials could cause unscheduled operational downtime or termination of customer contracts. Any failure to comply with applicable legal and regulatory international trade obligations could also result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of shipments and loss of import/export privileges.

We are subject to complex laws and regulations, including environmental laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to numerous stringent environmental, health and safety laws and regulations in the form of international conventions and treaties, national, state and local laws and regulations in force in the jurisdictions in which our drilling rigs operate or are registered, which can significantly affect the ownership and operation of the rigs. These requirements include, but are not limited to, the MARPOL, the International Convention on Civil Liability for Oil Pollution Damage of 1969 (the "CLC"), the International Convention on Civil Liability for Bunker Oil Pollution Damage ("Bunker Convention") and various international, national and local laws and regulations that impose compliance obligations and liability related to the use, storage, treatment, disposal and release of petroleum products, asbestos, polychlorinated biphenyls and other hazardous substances that may be present at, or released or emitted from, our operations. Furthermore, the United Nations' IMO, at the international level, or national or regional legislatures in the jurisdictions in which we operate, including the European Union, may pass or promulgate new climate change laws or regulations. Compliance with such laws, regulations and standards, where applicable, may require installation of costly equipment or operational changes and may affect the resale value or useful lifetime of our drilling rigs. We are required to obtain environmental, health and safety permits from governmental authorities for our operations. We may also incur additional costs in order to comply with other existing and future laws or regulatory obligations, including, but not limited to, costs relating to air emissions, including greenhouse gases, management of ballast waters, rig maintenance and inspection, development and implementation of emergency incidents. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our services by making them more or less desirable than services associated with competing sources of energy. If a major incident were to occur, such as the Macondo incident, in the markets in which we operate, this could lead to a regulatory response which may result in increased operating costs.

In the event we were to incur additional costs in order to comply with such existing or future laws or regulatory obligations, these costs could have a material adverse effect on our business, results of operations, cash flows and financial condition. A failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our operations. We could also be held responsible for costs relating to contamination at third party waste disposal sites used by us or on our behalf. Environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject us to liability without regard to whether we were negligent or at fault. For example, in certain jurisdictions, owners, operators and bareboat-charterers may be jointly and severally strictly liable for the discharge of oil in territorial waters, including the 200 nautical mile exclusive economic zone. An oil spill could result in significant liability, including fines, penalties and criminal liability and remediation costs for natural resource damages under the laws of the jurisdictions in which we operate, as well as third-party damages and material adverse publicity. We are required to satisfy insurance and financial responsibility requirements for potential oil (including marine fuel) spills and other pollution incidents and the insurance may not be sufficient to cover all such risks. In addition, laws and regulations may impose liability on generators of hazardous substances, and as a result we could face liability for cleanup costs at third-party disposal locations. Environmental claims against us could result in a material adverse effect on our business, results of operations, cash flows and financial condition. Failure to obtain or maintain environmental, health or safety permits or approvals may result in a material adverse effect on our business, results of operations, cash flows and financial condition.

Although some of our drilling rigs are separately owned by subsidiaries, under certain circumstances a parent company and all of the unit-owning affiliates in a company under common control engaged in a joint venture could be held liable for damages or debts owed by one of the affiliates, including liabilities for oil spills under environmental laws. Therefore, it is possible that we could be subject to liability upon a judgment against us or any one of our subsidiaries.

Our drilling rigs could cause the accidental release of oil or hazardous substances. Any releases may be large in quantity, above the permitted limits or occur in protected or sensitive areas where public interest groups or governmental authorities have special interests. Any releases of oil or hazardous substances could result in fines and other costs, such as costs to upgrade drilling rigs, clean up the releases (which may not be covered by contractual indemnification or insurance) and comply with more stringent requirements in our discharge permits, and claims for natural resource, personal injury or other damages. Moreover, these releases may result in customers or governmental authorities suspending or terminating our operations in the affected area, which could have a material adverse effect on our business, financial condition and results of operations.

Failure to comply with applicable anti-corruption laws, sanctions or embargoes, could result in fines, criminal penalties, drilling contract terminations and have an adverse effect on our business.

We operate drilling rigs in a number of countries, including in some developing economies, which can involve inherent risks associated with fraud, bribery and corruption. As a result, we may be subject to risks under the United States Foreign Corrupt Practices Act (the "FCPA"), the United Kingdom Bribery Act 2010 (the "Bribery Act") and similar laws in other jurisdictions. We are committed to doing business in accordance with applicable anti-corruption laws as well as sanctions and embargo laws and regulations (including US Treasury Office of Foreign Asset Control, or OFAC requirements) and have adopted policies and procedures, including our Code of Business Conduct and Ethics, which are designed to promote legal and regulatory compliance with such laws and regulations. However, our employees, agents and/or partners acting on our behalf may take actions determined to be in violation of such applicable laws and regulations. Any such violation could result in substantial fines, sanctions, deferred settlement agreements, civil and/or criminal penalties, curtailment of operations in certain jurisdictions, and might as a result materially adversely affect our business, financial condition or results of operations. In addition, actual or alleged violations could damage our reputation and ability to do business. Furthermore, detecting, investigating and resolving actual or alleged violations is expensive and can consume significant time and attention of our senior management.

Any failure to comply with the complex laws and regulations governing international trade, including import, export, economic sanctions and embargoes could adversely affect our operations.

The shipment of equipment and materials required for offshore drilling operations across international borders subjects us to extensive import and export laws and regulations governing our assets, equipment and materials, including those enacted by the United States and/or other countries in which we operate. Moreover, many countries control the export/import and re-export of certain goods, services and technology and may impose related export/import recordkeeping and reporting obligations. Governments also may impose economic sanctions and/or embargoes against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities.

These various jurisdictional laws and regulations regarding export/import controls and economic sanctions are complex, constantly changing, may be unclear in some cases and may be subject to changing interpretations. They may be enacted, amended, enforced or interpreted in a manner that could materially impact our operations. Materials shipments and rig import/export may be delayed and denied for a variety of reasons, some of which are outside our control, and including our failure to comply with existing legal and regulatory regimes. Delays or denials could cause unscheduled operational downtime or termination of customer contracts. Any failure to comply with applicable legal and regulatory international trade obligations could also result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of shipments and loss of import/export privileges.

The Company is exposed to regulatory and enforcement risks regarding taxes. U.S. tax authorities may treat the Company as a passive foreign investment company, causing potential adverse U.S. federal tax consequences to U.S. holders.

For U.S. federal income tax purposes, a foreign corporation will be treated as a Passive Foreign Investment Company ("PFIC"), if either (1) at least 75 percent of its gross income for any taxable year consists of certain types of "passive" income, or (2) at least 50 percent of the average value of the corporation's assets either produce or are held for the production of those types of "passive" income. Passive income for these purposes includes certain rents and royalties, dividends, interest, and gains for the sale or exchange of investment property. Passive income does not include income derived from the performance of services.

We believe that the Company will not be treated as a PFIC for any relevant period as any income the Company receives from offshore drilling service contracts should be treated as "services income" rather than as passive income under the PFIC rules. In addition, the assets the Company owns and utilizes to generate this "services income" should not be considered to be passive assets.

Although there is significant legal authority supporting the Company's position, including relevant statutory provisions, legislative history, case law and various pronouncements from the United States Department of Internal Revenue ("IRS"), there is a possibility that the IRS may still characterize this income as "passive" income in light of a recent case characterizing income from the time chartering of vessels as rental income rather than services income for other tax purposes. However, the IRS has subsequently formally announced that it does not agree with the decision in that case. Despite this IRS announcement, no assurance can be given that the IRS or a relevant court will accept the Company's position that the Company is not a PFIC.

If the Company was to be treated as a PFIC for any relevant period, the Company's U.S. shareholders may face adverse U.S. tax consequences. Under the PFIC rules, a U.S. shareholder would be liable to pay U.S. federal income tax at the highest applicable rates on ordinary income upon the receipt of certain "excess" distributions and upon any gain from the disposition of the Company's shares, plus certain interest and penalties. Although shareholders can make certain elections to mitigate the application of the PFIC rules, these elections can themselves cause other adverse tax consequences to the electing shareholder.

Any relevant change in tax laws, regulations, or treaties, and relevant interpretations thereof, for any country in which we operate or earn income or are considered to be a tax resident, may result in a higher effective tax rate on our worldwide earnings, which could have a material impact on our earnings and cash flows from operations.

We operate in many countries worldwide through our various subsidiaries. As such, we are subject to changes in applicable tax laws, regulations, or tax treaties, and the interpretation thereof in the various countries in which we operate or earn income or are deemed to be a tax resident. Such changes may result in a materially higher effective tax rate on our worldwide earnings and could result in material changes to our financial results.

The loss of any major tax dispute, or a successful challenge to our intercompany pricing policies or operating structures, or a taxable presence of our key subsidiaries in certain countries could result in a higher effective tax rate on our worldwide earnings, which could have a material impact on our earnings and cash flows from operations.

We are a Cayman corporation that operates through our many subsidiaries in various countries throughout the world. Our income taxes are based upon the relevant tax laws, regulations, and treaties that apply to the various countries in which we operate or earn income or are deemed to be a tax resident.

Our income tax returns are subject to examination and review. If any tax authority successfully challenges our intercompany pricing policies or operating structures, or if any tax authority interprets a treaty in a manner that is adverse to our structure, or if any tax authority successfully challenges the taxable presence of any of our key subsidiaries in a relevant jurisdiction, or if we lose a key tax dispute in a jurisdiction, our effective tax rate on worldwide earnings may increase substantially and our earnings and cash flow from operations could be materially impacted.

Item 2. Properties

Drilling Fleet

Jackup rigs are self-elevating drilling platforms equipped with legs that are lowered to the sea floor. A jackup rig can be towed to the drill site with its hull riding in the sea and its legs raised (a “wet tow”). Alternatively the jackup rig can be transported for long distances onboard a heavy-lift vessel with the entire rig travelling above water (a “dry tow”). At the drill site, the rig’s legs are lowered until they penetrate the sea bed and the hull is elevated until it is above the surface of the water. For the Company’s rigs, “preloading” is required to drive the legs into the sea bottom before the hull is completely jacked out of the water. The preload sequence is usually done in stages, with the hull never rising more than five feet out of the water to safeguard against having a leg punch through. Seawater is pumped into the rig’s preload tanks, adding weight to the hull and resulting in deeper penetration of the legs. After the legs are partially stabilized into the seabed and the hull is lowered into the water, the seawater is pumped overboard and the sequence is repeated. This process continues until the legs cannot penetrate the sea bottom any further. This allows loading the legs to a level above that which the unit is expected to encounter in the harshest predicted environment. After completion of drilling operations, the hull is lowered until it rests on the water, the legs are raised and the rig is ready to be relocated to another drill site.

The Company’s jackup rigs are generally suitable for water depths of 400 feet or less and have living quarters for up to 160 personnel. All of our jackup rigs are of the independent-leg cantilever design, which have greater operational flexibility and are generally considered safer, more efficient and more capable than alternative designs such as the mat-slot, mat-cantilever and independent-slot designs. Independent-leg cantilever is the jackup design preferred by our customers in each of the markets in which we operate. This design, which facilitates the ability to cantilever the drilling package over the platform, results in a large drilling envelope. This enables the drilling package to be moved in both a longitudinal and transversal direction without the need to move the physical location of the rig. In contrast, the drilling package on slot-designed rigs is limited to movement in a longitudinal direction only, parallel to the slot of the rigs, resulting in smaller drilling envelopes. When tendering for contracts, the Company generally competes against other operators of independent-leg cantilever rigs, rather than operators of other types of jackup rig.

The Company has added a new build rig, the Shelf Drilling Chaophraya, to its active fleet in December 2016. This “fit for purpose” rig is a Marathon LeTourneau Super 116 E design, capable of operating in water depths of up to 350 feet and for use in constructing wells with maximum drilling depth of 30,000 feet. The rig can accommodate 160 crew.

The Company also owns a heavy swamp barge which is capable of operating in very shallow waters of up to 21 feet in depth. The swamp barge is used in shallow inland waters or swamp locations and is also equipped with a complete cantilever drilling package, including three mud pumps and self-contained living quarters for 100 personnel. Upon being towed to a drilling location, the hull is flooded with water until securely positioned on the sea bottom. Upon completion of the contract, the barge’s hull is pumped dry until the barge is afloat and ready to be towed to its next drilling location.

The Company owns or leases office space and shore based facilities to support drilling operations in Indonesia, Malaysia, Vietnam, Singapore, Thailand, India, Egypt, Nigeria, Qatar, Italy, the UAE and Saudi Arabia.

Our total rig count is 37, including the swamp barge and the Newbuild under construction. The following table sets forth certain information concerning our fleet, excluding the Newbuild under construction, at December 31, 2016.

Name	Make	Year Built / Last Upgraded	Maximum Water Depth (feet)	Maximum Drilling Depth (feet)	Location	Status
Compact Driller	Marathon LeTourneau 116-C	1992/2013	300	25000	Bahrain	Active
Key Gibraltar	Marathon LeTourneau 84-C Mod	1976/2004	300	25000	Bahrain	Active
Key Hawaii	Mitsui 300 C	1983/2004	300	25000	Bahrain (1)	Active
Adriatic I	Marathon LeTourneau 116-C	1981/2014	350	25000	Cameroon	Active
Adriatic X	Marathon LeTourneau 116-C	1982/2006	350	30000	Cameroon	Active
Trident XIV	Baker Marine BMC 300-IC	1982/2007	300	25000	Cameroon	Active
Key Manhattan	Marathon LeTourneau 116-C	1980/2010	350	25000	Croatia (2)	Active
Comet	Sonat Cantilever	1980	250	20000	Egypt	Active
Rig 141	Marathon LeTourneau 82-SD-C	1982	250	20000	Egypt	Active
Rig 124	Modec 200-C45	1980	250	20000	Egypt	Active
Trident 16	Modec 300-C38	1982/2012	300	25000	Egypt	Active
C.E. Thornton	Marathon LeTourneau 53-SC	1974/1984	300	21000	India	Active
F.G. McClintock	Marathon LeTourneau 53-SC	1975/2002	300	21000	India	Active
Galveston Key	Marathon LeTourneau 116-SC Mod	1978/2002	300	25000	India	Active
Harvey H. Ward	F&G L-780 Mod II	1981/2011	300	25000	India	Active
J.T. Angel	F&G L-780 Mod II	1982	300	25000	India	Active
Parameswara	Baker Marine BMC 300-IC	1983/2001	300	20000	India	Active
Ron Tappmeyer	Marathon LeTourneau 116-C	1978	300	25000	India	Active
Trident II	Marathon LeTourneau 84-SC Mod	1977/1985	300	21000	India	Active
Trident XII	Baker Marine BMC 300-IC	1982/1992	300	21000	India	Active
Trident 15	Modec 300-C38	1982/2014	300	25000	Malaysia	Active
Baltic	Marathon LeTourneau Super 300	1983/2015	375	25000	Nigeria	Active
Trident VIII	Modec 300-C35	1981	300	21000	Nigeria	Active
Main Pass I	F&G L-780 Mod II	1982/2013	300	25000	Saudi Arabia	Active
High Island II	Marathon LeTourneau 82-SD-C	1979/2011	270	20000	Saudi Arabia	Active
High Island IV	Marathon LeTourneau 82-SD-C	1980/2011	270	20000	Saudi Arabia	Active
High Island V	Marathon LeTourneau 82-SD-C	1981/2013	270	20000	Saudi Arabia	Active
High Island IX	Marathon LeTourneau 82-SD-C	1983/2012	250	20000	Saudi Arabia	Active
Main Pass IV	F&G L-780 Mod II	1982/2012	300	25000	Saudi Arabia	Active
Shelf Drilling Chaophraya	LeTourneau Super 116 E	2016	350	30000	Thailand	Active
High Island VII	Marathon LeTourneau 82-SD-C	1982/2016	250	20000	UAE	Active
Key Singapore	Marathon LeTourneau 116-C	1982/2015	350	25000	UAE	Active
Randolph Yost	Marathon LeTourneau 116-C	1979	300	25000	USA	Active
Adriatic IX	Marathon LeTourneau 116-C	1981/1995	350	25000	Cameroon	Stacked
Hibiscus	Heavy Swamp Barge	1979/1993	21	20000	Indonesia	Stacked
Trident IX	Modec 400-C	1982/2009	400	21000	Malaysia	Stacked

(1) Rig was undergoing contract preparation in Bahrain as of December 31, 2016, contract will commence in the location listed.

(2) Rig is currently on drilling holiday until December 31, 2017.

Note: Rigs listed as "Active" were either operating under contract or operational and actively being marketed. Rigs listed as "Stacked" were idle without a contract and not actively marketed.

Item 3. Legal Proceedings

Information regarding legal proceedings is set forth in *Note 13 Commitments and Contingencies* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

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

The Company has authorized five million shares of common stock with a par value of $0.01 a share. One share is issued and outstanding and is held by SDIL. Total recorded shareholder’s equity of the Company was $676.4 million, $801.0 million and $976.1 million at December 31, 2016, 2015 and 2014, respectively.

Item 6. Selected Financial Data

The following table sets forth selected financial data of the Company. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in our financial statements included in Item 8 of this Annual Report on Form 10-K.

	Years ended December 31,		
	2016	2015	2014
		(In thousands)	
Operating revenues	$ 668,649	$ 1,012,757	$ 1,213,700
Operating income / (loss)	69,914	(67,595)	377,749
Net income / (loss)	10,865	(140,123)	284,229
Total debt (1)	711,562	538,907	460,502
Total assets	1,531,313	1,525,952	1,756,154
Cash dividends and cash dividends per share (2)	135,644	35,591	156,809

(1) Total debt consists of long-term debt and current and non-current obligations under sale and leaseback.

(2) Cash dividends and cash dividends per share are equal since there is only one share outstanding.

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

The following discussion is intended to assist you in understanding our financial position at December 31, 2016 and December 31, 2015. You should read the accompanying consolidated financial statements and related notes in conjunction with this discussion.

Outlook

Demand for the Company’s fleet of shallow water drilling rigs is driven by customer spending, which can experience fluctuations depending on current commodity prices and market expectations of future price levels. The business environment for offshore drillers remains very challenging, as operators have announced declines in spending and cancelled or deferred projects over the last two years in light of the precipitous drop in crude oil prices. Crude oil prices have ranged from an annual average of $98.97 to $43.55 per barrel during last three years ending at $54.96 per barrel as at December 31, 2016. Although crude oil prices have begun to recover and stabilize in recent months, we believe that the market outlook continues to be more challenging compared with previous years due to the current lower levels of rig demand, combined with a significant oversupply of available jackups.

A total of 19 new jackup rigs have been delivered during the year 2016. Further, there were 104 additional jackup rigs on order or under construction, of which six rigs have contracts secured for their future delivery dates. These rigs are currently scheduled for delivery between 2017 through 2020. We anticipate several of these rigs to be cancelled and many others will likely continue to be deferred until a recovery in demand is visible.

While the shallow water market has been more resilient than the deepwater market, dayrates and utilization for all offshore rigs have been significantly impacted. In general, recent contract awards have been short-term in nature and subject to an extremely competitive bidding process. The intense pressure on operating day rates has resulted in rates that approximate direct operating expenses. In addition, we are seeing increased pressure to accept other less favorable contractual and commercial terms, including reduced or no mobilization and/or demobilization fees, reduced early termination fees and/or termination notice periods.

While we are starting to see an increase in potential contract opportunities, price competition remains extremely intense, and we expect to see continued pressure on dayrates for existing and new contracts in the near term. Additionally, the customers may continue to seek to renegotiate or terminate existing contracts.

At December 31, 2016, the Company's contract backlog is $1.7 billion across 25 contracted rigs (including one new build rig under construction). During the year ended December 31, 2016, we entered into a total of 11 contracts resulting from new business, contract extensions, and exercised options, with a weighted average dayrate of $64.8 thousand. The Company remains focused on delivering safe and efficient operations, as well as realizing cost savings and efficiency gains across all levels of the organization.

Significant Factors Affecting Results of Operations

We believe that the following factors have had, and will continue to have, a material effect on our business, financial condition and results of operations. As many of these factors are beyond our control, past performance will not necessarily be indicative of future performance, and it is difficult to predict future performance with any degree of certainty. In addition, important factors which could cause actual operations or financial conditions to differ materially from those expressed or implied below include, but are not limited to, factors described in this document under "Item 1A. Risk Factors" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risks".

Contract backlog

Contract backlog represents the maximum contract drilling dayrate revenues that can be earned in the future in relation to a drilling contract on the basis of the contract operating dayrate less any estimated future planned out of service periods during the firm contract period for regulatory inspections and surveys or other work. Contract backlog excludes revenue resulting from mobilization fees, capital or upgrade reimbursement, recharges, bonuses and other revenue sources.

The Company's contract backlog includes only firm commitments for contract drilling services, which are represented by signed drilling contracts or, in some cases, by other definitive agreements to be formalized in a future contractual agreement. Only the initial firm contract period is included in contract backlog and additional contractual periods resulting from the exercise of extension option(s) are excluded until they are exercised. The contract operating dayrate used in the calculation of contract backlog may be higher than the actual dayrate we ultimately receive and may be replaced for temporary periods of time during the contract period by an alternative contractual dayrates, such as a waiting-on-weather rate, repair rate, standby rate, force majeure rate or mobilization rate, each of which may apply under certain circumstances. The contract operating dayrate used in the calculation of contract backlog may also be higher than the actual dayrate the Company ultimately receives because of a number of factors resulting in lost dayrate revenue, including rig downtime or suspension of operations. In certain contracts, the dayrate may be reduced to zero if, for example, repairs extend beyond a stated period of time. The Company's contracts also typically include a provision that allows the customer to extend the term period of the contract to finish drilling a well-in-progress. In a limited number of contracts, the customer may cancel the contract without cause or payment of an early termination fee by serving a certain period of notice. The period of time beyond the term of the contract to finish drilling a well-in-progress and the associated dayrate revenue is not included in the calculation of the contract backlog.

While backlog is a key performance indicator of future business, it may increase or decrease depending on various factors, such as the timing of new contracts or contract extensions and out of service periods. Certain of our contracts with customers may be cancelable at their discretion upon payment of early termination fees. Such payments, however, may not fully compensate us for losses associated with cancellation of the contract. Contracts also customarily provide, under certain circumstances, for either automatic termination or termination at the option of the customer typically without any additional payments. Such terminations may occur as a result of non-performance, unplanned downtime or impaired performance caused by equipment or operational issues and sustained periods of downtime due to force majeure events. Many of these events are beyond the Company's control.

During periods of depressed market conditions, our customers may seek to reduce or repudiate their obligations through renegotiating drilling contracts. Customer cancellation or suspension of contracts and the inability of the Company to secure new contracts on a timely basis on substantially similar terms could adversely affect our consolidated results of operations and cash flows. In the recent years, some of our customers have renegotiated contracts because of depressed market conditions, lower commodities prices and economic downturns, resulting in lower dayrates. Refer to *"Results of Operations"* for further details.

At December 31, 2016, the Company's contract backlog was $1.7 billion with a weighted average backlog dayrate of $96.7 thousand per day.

The following table sets out the future years which the contract backlog relates to, at December 31, 2016:

	2017	2018	2019	Thereafter	Total at December 31, 2016
Total contract backlog *(in millions)*	$ 572.1	$ 538.4	$ 327.4	$ 305.4	$ 1,743.3
Weighted average backlog dayrate (1) *(in thousands)*	$ 76.7	$ 87.6	$ 102.4	$ 100.9	$ 96.7

(1) The weighted average backlog dayrate is obtained by calculating the Company's total backlog divided by the total number of backlog days for all the rigs.

The following table lists contract backlogs for the Company's drilling fleet at December 31, 2012 through 2016.

	At December 31,				
	2012	2013	2014	2015	2016
Total contract backlog (1) *(in millions)*	$1,566	$2,091	$3,162	$2,346	$1,743
Weighted average backlog dayrate (2) *(in thousands)*	$102.7	$111.1	$123.8	$99.4	$96.7
Average contract days per rig	462	537	690	762	721
Number of contracted rigs (3)	33	35	37	31	25

(1) Starting 2014, amounts include Newbuild rig(s) under construction.

(2) The weighted average backlog dayrate is obtained by calculating the Company's total backlog divided by the total number of backlog days for all the rigs.

(3) This includes Newbuild rig(s) under construction and rig under bareboat charter.

Contract backlog is also impacted by overall industry activity level, global macro-economic conditions, supply and demand, and other factors. The increase in contract backlog since the Acquisition until 2014 reflects the Company's continued success in winning new contracts and customer exercises of options on existing contracts. However, the uncertainty in the offshore drilling industry in the recent years has resulted in the industry wide year-over-year reduction in contract backlog.

Key Performance Indicators

The table below sets out the Company's drilling fleet uptime, total recordable incident rate, marketed utilization, average earned dayrate and marketable rigs for the years ended December 31, 2012 through 2016. Data for the Company's drilling fleet prior to the Acquisition is derived from Transocean's unaudited rig level financial information.

	Years ended December 31,				
	2012	2013	2014	2015	2016
Uptime (%)	98.7%	98.9%	98.5%	98.6%	98.7%
Total Recordable Incident Rate	0.88	0.67	0.48	0.22	0.25
IADC Average TRIR (1)	0.88	0.81	0.75	0.6	n/a
Marketed Utilization (%)	90%	91%	89%	72%	74%
Average dayrate *(in thousands)*	$ 91.8	$ 102.7	$ 111.0	$ 104.3	$ 75.2
Average marketable rigs	31.0	32.7	34.6	34.5	31.2

(1) In 2016, the information is not available as of the date of issuance of the report.

Uptime

We define uptime as the period of time during which the Company performs well operations without stoppage due to mechanical, procedural or other significant operational events that result in non-productive well operations time. Uptime is expressed as a percentage and can be measured over various periods such as daily, monthly or yearly. Uptime performance is a key customer contracting criterion and is directly related to the Company's current and future revenue and profit generation. Historically, the Company's fleet of rigs has delivered high levels of uptime which continued in the current year with uptime performance for 2016 of 98.7%.

Total Recordable Incident Rate

Total recordable incident rate (''TRIR'') is a measure of the rate of recordable workplace injuries. TRIR, as defined by the International Association of Drilling Contractors, is determined over a 12-month period and is derived by multiplying the number of recordable injuries in a calendar year by 200,000 and dividing this value by the total hours actually worked in the year by the total number of employees. An incident is considered ''recordable'' if it results in medical treatment over certain defined thresholds (such as receipt of prescription medication or stitches to close a wound) as well as incidents requiring the injured party to spend time away from work. The Company's senior management, rig crews and employees are incentivized based on the Company's safety performance. The Company strives to achieve an incident free workplace environment which would result in a TRIR of zero. The Company's personnel and contractors achieved a TRIR of 0.25 in 2016.

Marketable rigs

We define marketable rigs as the average number of rigs excluding stacked rigs, rigs undergoing reactivation projects, rigs under bareboat charter and newbuild rigs under construction. At the close of the Acquisition, of the 38 drilling rigs purchased from Transocean, 31 were marketable, two rigs were undergoing reactivation projects and the five remaining rigs were stacked. The Company has reactivated three of five rigs which were stacked and completed the reactivation of the two rigs that were undergoing reactivation at the time of the Acquisition. In 2016, the Company has sold the remaining two stacked rigs.

At December 31, 2016, of the Company's 36 rigs, 32 were marketable (of which 23 were under contract and nine were actively being marketed), one rig was under bareboat charter and three rigs were stacked. The Company currently has no near term plans to reactivate the stacked rigs.

In addition, the Company has one newbuild rig which is undergoing construction and is expected to be delivered in the UAE in the second quarter of 2017.

Average dayrate

The Company defines average dayrate as the average contract dayrate earned by marketable rigs over the reporting period excluding amortization of lump sum mobilization fees, contract preparation and capital expenditure reimbursements, recharges, bonuses and other revenues. See "Customer contracts" for further details on dayrates.

An over-supply of drilling rigs or lower demand for drilling rigs in markets in which we operate may also adversely affect our ability to acquire or extend contracts at favorable dayrates in those areas. In some cases the contractual dayrates have been renegotiated in light of the current market conditions. The dayrates and new contracts (including extensions) reflected in recent contract activity are impacted by the current overall industry activity level and rig supply and demand.

During the year ended December 31, 2016, a combination of 11 new contracts and extension options, with a weighted average dayrate of $64.8 thousand, were signed. The average realized dayrate for the Company's drilling fleet, excluding one rig under bareboat charter, was $75.2 thousand for the year ended December 31, 2016.

Marketed Utilization

Marketed utilization measures the dayrate revenue efficiency of the marketable rigs. We define marketed utilization as the actual number of calendar days during which marketable rigs generate dayrate revenues divided by the maximum number of calendar days during which those same rigs could have generated dayrate revenues. Marketed utilization varies due to changes in revenue earned resulting from the operational uptime of a rig, the planned downtime of a rig for periodic surveys, timing of underwater inspections, contract preparation and rig upgrades, the time between contracts and the application of alternative contractual dayrates, such as a waiting-on-weather rate, repair rate, standby rate, force majeure rate, mobilization rate or zero rate, that may apply under certain circumstances. We exclude cash received for lump sum mobilization fees and capital and upgrade reimbursements from contract dayrate revenues used in calculating marketed utilization; these amounts are deferred and amortized as revenue over the initial period of the contract excluding any extension options. We also exclude revenue earned from bonuses, recharges, the amortization of fair value of contract intangibles at Acquisition and lump sum demobilization revenue in calculating marketed utilization. The timing of planned downtime for marketable rigs will fluctuate between quarters as well as from year to year. Therefore such downtime can positively or negatively impact revenue, operating costs, the associated Adjusted EBITDA and net income after tax when comparing across periods.

SHELF DRILLING

Results of Operations

Year ended December 31, 2016 compared to the year ended December 31, 2015

	Years ended December 31, 2016	Years ended December 31, 2015	Change	% change
	(In thousands except percentages)			
Revenues				
Operating revenues	$ 668,649	$ 1,012,757	$ (344,108)	-34%
Amortization of drilling contract intangibles	-	983	(983)	-100%
Other operating revenue	15,668	17,558	(1,890)	-11%
	684,317	1,031,298	(346,981)	-34%
Operating costs and expenses				
Operating and maintenance	354,095	534,156	(180,061)	-34%
Depreciation	71,780	87,421	(15,641)	-18%
Amortization of deferred costs	91,763	80,984	10,779	13%
General and administrative	44,845	138,996	(94,151)	-68%
	562,483	841,557	(279,074)	-33%
Gain on insurance recovery	-	25,432	(25,432)	-100%
Loss on impairment of assets	(47,094)	(271,469)	224,375	-83%
Loss on disposal of assets	(4,826)	(11,299)	6,473	-57%
Operating income / (loss)	69,914	(67,595)	137,509	-203%
Other (expense) / income, net				
Interest income	356	102	254	249%
Interest expense and financing charges	(41,170)	(41,384)	214	-1%
Other, net	1,522	(873)	2,395	-274%
	(39,292)	(42,155)	2,863	-7%
Income / (loss) before income taxes	30,622	(109,750)	140,372	-128%
Income tax expense	19,757	30,373	(10,616)	-35%
Net income / (loss)	$ 10,865	$ (140,123)	$ 150,988	-108%

Revenues

Total revenue for 2016 was $684.3 million compared to $1,031.3 million for 2015. Revenue for 2016 consisted of $668.6 million (97.7 %) of operating revenue and $15.7 million (2.3%) of other operating revenue. In 2015, these same revenues were $1,012.7 million (98.2%) and $17.5 million (1.7%), respectively. In addition, there were nil and $983 thousand non-cash revenue related to the amortization of the fair market value of the remaining existing drilling service contracts acquired at the time of the Acquisition during the year ended December 31, 2016 and 2015, respectively.

Revenue for 2016 decreased by $347.0 million compared to the same period in 2015 primarily due to $230.4 million lower average earned dayrates ($75.2 thousand in 2016 compared to $104.3 thousand in 2015), $71.0 million lower marketable rig count (three rigs stacked in 2016, one rig ceased operations on March 22, 2015 following a fire incident and one rig operating under bareboat charter, partly offset by one rig reactivated which started operations in September 2015 and one Newbuild which started operations in December 2016), $17.6 million lower mobilization revenue amortization in 2016, $8.5 million lower recharge revenue across the fleet, $8.2 million lower revenue related to contract termination fees and $7.6 million for more rigs awaiting marketing opportunities in 2016 compared to 2015.

Marketed utilization for 2016 of 74% was higher than the marketed utilization for 2015 of 72% mainly due to lower number of rigs in shipyards undergoing contract preparation during the year ended December 31, 2016. There were 10 rigs for 555 days in shipyard undergoing contract preparation during the year ended December 31, 2016, compared with 12 rigs for 1,355 days during the year ended December 31, 2015.

Operating and maintenance expenses

Total operating and maintenance expenses for 2016 were $354.1 million or 51.7% of total revenue compared to $534.1 million or 51.8% of total revenue (excluding amortization of drilling contract intangibles) for the same period in 2015. Operating and maintenance expenses included $218.3 million for personnel expenses, $95.0 million for asset management and maintenance expenses and $40.8 million for miscellaneous operating and administrative expenses, including insurance premiums, compared to the same period in 2015 when such expenses were $334.3 million, $188.3 million and $11.5 million for those respective categories.

Operating and maintenance expenses decreased by $180.0 million mainly due to $70.8 million of cost savings across rigs and shorebase offices, $54.2 million lower expenses for idle rigs awaiting marketing opportunities, $26.5 million lower costs due to additional stacked rigs in 2016 compared with 2015, $25.3 million lower maintenance and shipyard expenses, $6.0 million lower costs for a rig that is operating under a bareboat charter agreement since February 2016 whereby the operator bears the operating and maintenance costs, $3.6 million lower reactivation costs (no rig under reactivation in 2016 compared to one rig under reactivation in 2015), and $1.7 million lower costs on a rig that ceased operations on March 22, 2015 following a fire incident. This was partly offset by $6.6 million higher costs related to a rig which was operating in 2016 but undergoing reactivation in 2015 and $1.5 million costs on one newbuild that started operations on December 1, 2016.

Depreciation expense

Depreciation expense for 2016 was $71.8 million compared to $87.4 million in 2015. The decrease of $15.6 million primarily related to $18.6 million lower depreciation on drilling rigs and equipment which were impaired in 2015. This was partly offset by the depreciation on the total additions to property and equipment including the capital expenditure transferred from construction in progress to completed assets related to rig based capital equipment and shipyard costs.

Amortization of deferred costs

The amortization of deferred costs was $91.8 million and $81.0 million for 2016 and 2015, respectively. The $10.8 million increase in amortization primarily related to the 2016 addition of deferred costs and the accelerated recognition of amortization of deferred costs amounting to $11.1 million for contracts which were early terminated during 2016.

General and administrative expenses

General and administrative expenses for 2016 were $44.8 million compared to $139.0 million for 2015. The $94.2 million decrease in general and administrative expenses primarily resulted from the decrease of $87.8 million for the net provision for doubtful debts, as there was a release of $7.8 million provision for doubtful debt partly offset by the additional provision of $7.4 million in 2016 compared to a provision of $87.4 million in 2015, $5.9 million cost reductions and $459 thousand lower share-based compensation expense.

Gain on insurance recovery

Gain on insurance recovery was nil and $25.4 million for 2016 and 2015, respectively. The gain related to the gross insurance proceeds less associated costs pertaining to a fire incident on one of the Company's rigs that resulted in the rig being declared a total constructive loss by the Company's insurance underwriters in 2015.

Loss on impairment of assets

Loss on impairment of assets was $47.1 million for 2016 compared to $271.5 million for 2015, on three and 13 of the Company's rigs, out of which one rig and five rigs were impaired to salvage values, respectively. The Company had written off the goodwill of $9.3 million in 2015. The impairment loss was recorded as a result of indicators of impairment including the reduction in the number of prospective contract opportunities, lower dayrates and utilization rates due to significantly lower crude oil prices, a decrease in worldwide demand and an increase in the global supply of jackup drilling rigs.

Other income and expense

Other income and expense totaled $39.3 million in 2016 and $42.2 million for 2015. Other expense consisted primarily of interest expense and financing charges of $41.2 million and $41.4 million during the year ended December 31, 2016 and 2015, respectively. Interest expense and financing charges are related to the SDHL Senior Secured Notes, Revolving Credit Facility ("SDHL Revolver") and sale and leaseback financing facilities.

Other, net were $1.5 million favorable in 2016 compared to $873 thousand unfavorable in 2015.

Income tax expense

Income tax expense for 2016 was $19.8 million compared to 2015 income tax expense of $30.4 million. While the Company is exempt from all income taxation in the Cayman Islands, a provision for income taxes is recorded based on the tax laws and rates applicable in the jurisdictions in which the Company operates and earns income or is considered resident for income tax purposes. The relationship between the provision for or benefit from income taxes and the income or loss before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues rather than income before taxes, (c) rig movements between taxing jurisdictions and (d) the Company's rig operating structures.

The primary reason for the decrease in income tax expense for 2016 compared to 2015 is that the overall taxable income (excluding loss on impairment of assets) for the Company has decreased significantly in 2016 as compared to 2015 primarily due to reduced revenues in 2016 as compared to 2015.

Year ended December 31, 2015 compared to the year ended December 31, 2014

	Years ended December 31, 2015	Years ended December 31, 2014	Change	% change
	(In thousands except percentages)			
Revenues				
Operating revenues	$ 1,012,757	$ 1,213,700	$ (200,943)	-17%
Amortization of drilling contract intangibles	983	31,522	(30,539)	-97%
Other operating revenue	17,558	20,804	(3,246)	-16%
	1,031,298	1,266,026	(234,728)	-19%
Operating costs and expenses				
Operating and maintenance	534,156	667,162	(133,006)	-20%
Depreciation	87,421	81,711	5,710	7%
Amortization of deferred costs	80,984	48,809	32,175	66%
General and administrative	138,996	87,674	51,322	59%
	841,557	885,356	(43,799)	-5%
Gain on insurance recovery	25,432	-	25,432	100%
Loss on impairment of assets	(271,469)	-	(271,469)	100%
Loss on disposal of assets	(11,299)	(2,921)	(8,378)	287%
Operating income / (loss)	(67,595)	377,749	(445,344)	-118%
Other (expense) / income, net				
Interest income	102	21	81	386%
Interest expense and financing charges	(41,384)	(50,180)	8,796	-18%
Other, net	(873)	(329)	(544)	165%
	(42,155)	(50,488)	8,333	-17%
Income / (loss) before income taxes	(109,750)	327,261	(437,011)	-134%
Income tax expense	30,373	43,032	(12,659)	-29%
Net income / (loss)	$ (140,123)	$ 284,229	$ (424,352)	-149%

Revenues

Total revenues for 2015 were $1,031.3 million compared to $1,266.0 million for 2014. Revenue for 2015 consisted of $1,030.3 million (99.9%) of operating revenues (including other operating revenue) and $983 thousand (0.1%) of revenue related to the amortization of the fair market value of existing contracts at the time of the Acquisition. In 2014, these revenues were $1,234.5 million (97.5%) and $31.5 million (2.5%), respectively. Operating revenues (including other operating revenue) in 2015 were comprised of $1,030.3 million in revenue earned by Company managed rigs and nil in net revenues for rigs under Operating Agreements with the Seller. Operating revenues (including other operating revenue) for 2014 were comprised of $1,194.2 million and $40.3 million in those respective categories. As of January 1, 2015, no rigs were being operated by the Seller under the Operating Agreements and the Company had assumed operation of all of its rigs.

Revenues in 2015 decreased by $234.7 million compared to 2014 primarily due to $124.2 million for more rigs awaiting marketing opportunities during the year ended December 31, 2015 compared to the year ended December 31, 2014, $70.4 million less revenue as a result of higher shipyard activity for rigs undergoing contract preparation work for new contracts in 2015 compared to 2014, $66.1 million for three rigs under contract for which the Company stopped recognizing revenue in Q3, 2015 due to collectability issues compared to nil during 2014, $53.2 million due to lower average earned dayrates ($104.3 thousand in 2015 compared to $111.0 thousand in 2014), $30.5 million for lower amortization of the fair market value of drilling service contracts acquired at the time of the Acquisition as these contracts expired, $19.1 million for a rig that was declared by the Company's insurance underwriters on August 26, 2015 as Constructive Total Loss following a fire incident which occurred in Q1, 2015 and $11.9 million for lower recharge revenue across the fleet. This was partly offset by $75.2 million of costs and taxes which were netted against revenue in 2014 from rigs that were operated by the Company in 2015 but which were operated by the Seller in 2014 under the Operating Agreements, $32.9 million related to two rigs which were reactivated and placed into operational service in June, 2014 and September 2015, respectively, $17.5 million for contract early termination fee for a rig, $9.0 million higher mobilization revenue amortization in 2015, $3.6 million for recovery of disputed revenue and $2.5 million for liquidated damages paid for a rig in 2014.

Marketed utilization for 2015 of 72% was lower than the marketed utilization for 2014 of 89% due to more rigs in shipyards undergoing contract preparation during the year ended December 31, 2015 and more rigs in between contracts awaiting marketing opportunities in 2015 compared with 2014. There were 12 rigs in shipyards undergoing contract preparation during the year ended December 31, 2015, one of which was in shipyard twice during the year compared with 11 rigs during the year ended

December 31, 2014 which resulted in a decrease in revenue by $70.4 million in 2015. Amortization of the fair market value of existing drilling service contracts acquired at the time of the Acquisition decreased as a result of all of the drilling service contracts acquired at the time of Acquisition having been completed during 2015.

Operating and maintenance expenses

Total operating and maintenance expenses for 2015 were $534.1 million or 51.8% of total revenue (excluding amortization of drilling contract intangibles) compared to $667.2 million or 54.0% of total revenue (excluding amortization of drilling contract intangibles) for 2014. Operating and maintenance expenses comprised of $334.3 million for personnel expenses, $188.3 million for asset management and maintenance expenses and $11.5 million for miscellaneous operating and administrative expenses, including insurance premiums, compared to 2014 when such expenses were $374.5 million, $215.6 million and $77.1 million for those respective categories. In 2014, $64.9 million of operating and maintenance expenses incurred by rigs operated by the Seller on behalf of the Company were netted against the 2014 revenue in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). From January 1, 2015, all the Company owned rigs were operated by the Company. Therefore, there were nil operating and maintenance expenses netted against revenue for the year ended December 31, 2015.

Including the $64.9 million of operating and maintenance expenses for rigs operated by the Seller in 2014, the 2015 operating and maintenance expenses were $198.0 million (27.0%) lower than the 2014 operating and maintenance expenses.

Operating and maintenance expenses decreased by $133.1 million mainly related to $96.7 million of cost savings across rigs and shorebase offices, $53.5 million lower expenses for idle rigs awaiting marketing opportunities, $33.0 million lower reactivation cost (one rig under reactivation in 2015 compared to two rigs under reactivation for part of 2014), $10.5 million lower maintenance and shipyard expenses, $8.5 million lower costs due to a fire incident in Q1, 2015 on one rig that was declared Constructive Total Loss by the Company's insurance underwriters on August 26, 2015, $4.0 million lower rig inventory acquisition costs as the Company had completed the transfer of all rig operations from the Seller by January 1, 2015 and $2.7 million lower boat costs associated with rig exports / imports. This was partly offset by $64.9 million for additional rigs that were operated by the Company in 2015 which were previously operated by the Seller under the Operating Agreements and $10.9 million higher costs primarily for two rigs which were reactivated and commenced operational service in June, 2014 and September, 2015.

Depreciation expense

Depreciation expense for 2015 was $87.4 million compared to $81.7 million in 2014. The increase of $5.7 million relates to the depreciation of the total additions to property and equipment during 2015 including the capital expenditure transferred from construction in progress to completed assets related to reactivation projects, rig based capital equipment and shipyard costs.

Amortization of deferred costs

Amortization of deferred costs for 2015 was $81.0 million compared to $48.8 million in 2014. The increase of $32.2 million relates to the higher amortization of deferred costs for periodic surveys, major overhauls, underwater inspections in lieu of drydock and contract preparations which are amortized over the period until the next similar activity or contract, out of which $6.6 million was related to the accelerated amortization of deferred costs for two rigs following the cessation of recognizing revenue for these two rigs.

General and administrative expenses

General and administrative expenses for 2015 were $139.0 million compared to $87.7 million for 2014. The $51.3 million increase in general and administrative expenses primarily results from the $64.8 million increase in the uncertainty of collectability of receivables provision partly offset by $10.6 million costs reductions and $2.9 million lower start-up costs. In 2014, general and administrative expenses included corporate expenses as well as a fixed rate per day per rig paid to Transocean under the Transition Services Agreement. As of January 1, 2015 the Company is no longer paying Transocean under the Transition Services Agreement. There were nil start-up costs in 2015.

Gain on insurance recovery

Gain on insurance recovery was $25.4 million compared to nil for 2014. The gain relates to the gross insurance proceeds less associated costs relating to a fire incident on one of the Company's rigs that resulted in the rig being declared a total constructive loss by the Company's insurance underwriters.

Loss on impairment of assets

Loss on Impairment of Assets was $271.5 million compared to nil for 2014. This non-cash impairment loss represents the write-off of the goodwill balance of $9.3 million and a $262.2 million impairment loss on 13 of the Company's rigs, out of which 5 rigs were fully impaired. The impairment loss was recorded as a result of recent events impacting the Company, including the reduction in the number of new contract opportunities, recent lower dayrates and utilization rates due to the decrease in crude oil prices, the decrease in global demand and the increase in the global supply of jackup drilling services.

Other income and expense

Other income and expense totaled $42.2 million in 2015 and $50.5 million for 2014. Other expense consisted primarily of interest expense and financing charges of $41.4 million and $50.2 million during the year ended December 31, 2015 and 2014, respectively. Interest expense and financing charges are related to the SDHL Senior Secured Notes, SDHL Revolver and sale and leaseback financing facilities. Interest expense and financing charges for the year ended December 31, 2015 were $8.8 million lower compared with the year ended December 31, 2014 and were mainly related to the $7.6 million increase in capitalized interest against the new builds under construction and $4.1 million reduction of interest costs and accelerated amortization of financing costs due to the repayment of the outstanding principal of $74.25 million of the $75 million Term Loan in February, 2014. This was partly offset by $1.8 million higher financing costs in relation to the Sale and Leaseback transactions and $1.1 million higher amortization of financing costs.

Income tax expense

Income tax expense for 2015 was $30.4 million compared to 2014 income tax expense of $43.0 million. While the Company is exempt from all income taxation in the Cayman Islands, a provision for income taxes is recorded based on the tax laws and rates applicable in the jurisdictions in which the Company operates and earns income or is considered resident for income tax purposes. The relationship between the provision for or benefit from income taxes and the income or loss before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues rather than income before taxes, (c) rig movements between taxing jurisdictions and (d) the Company's rig operating structures.

The primary reason for the decrease in income tax expense for 2015 compared to 2014 is that overall taxable income for the Company has decreased significantly in 2015 as compared to 2014, primarily due to reduced revenues in 2015 as compared to 2014. This decrease in income tax expense is despite the fact that, during 2014, $8.3 million of income taxes related to rigs operated by the Seller under various Operating Agreements were excluded from the income tax expense of the Company as such taxes were reflected as a component of net revenues under the Operating Agreements. As of January 1, 2015, all Operating Agreements have concluded and therefore the income taxes related to rigs formerly operated by the Seller under such Operating Agreements are included in income tax expense of the Company.

Adjusted Revenues and Adjusted EBITDA

Revenues generated by rigs operated by Transocean under the Operating Agreements were recorded by the Company as net revenue. Net revenue represents customer revenue less expenses related to the operation of the rigs (which comprises personnel, asset management and maintenance, and operating, miscellaneous and administration expenses), shore based fixed fees, corporate services fixed fees and taxes paid by Transocean. We define Adjusted Revenues as the sum of revenue from rigs operated by the Company, gross revenue from rigs operated by Transocean under the Operating Agreements and other operating revenue. Adjusted Revenues exclude amortization of the fair market value of existing contracts at the time of Acquisition.

The table below reconciles operating revenues to Adjusted Revenue. The information in the table below has been extracted without material adjustment from the financial information set out in "Item 8. Financial Statements and Supplementary Data" or the underlying accounting records of the Company which formed the basis of this financial information.

	Years ended December 31,		
	2016	2015	2014
		(In thousands)	
Revenue from rigs operated by the Company	$ 668,649	$ 1,012,757	$ 1,173,441
Net revenue from rigs operated by Transocean under the Operating Agreements	-	-	40,259
Operating revenues	668,649	1,012,757	1,213,700
Net revenue from rigs operated by Transocean under the Operating Agreements	-	-	40,259
Add back:			
Operating and maintenance expense	-	-	64,946
General and administrative expense	-	-	1,986
Income tax expense	-	-	8,307
Other income	-	-	(13)
Gross revenue from rigs operated by Transocean under the Operating Agreements	$ -	$ -	$ 115,485
Other operating revenue	15,668	17,558	20,804
Adjusted revenues	$ 684,317	$ 1,030,315	$ 1,309,730

Management believes that presentation of Adjusted revenues is useful to the reader of this Annual Report on Form 10-K as it provides information on our revenues which is more comparable to that presented by companies in the industry who do not have Operating Agreements, and accordingly report all their revenues on a gross basis.

The table below reconciles net income to Adjusted EBITDA. The information in the table below has been extracted without material adjustment from the financial information for the Company set out in "Item 8. "Financial Statements and Supplementary Data" or the underlying accounting records of the Company which formed the basis of this financial information.

	Years ended December 31,		
	2016	2015	2014
		(In thousands)	
Net income / (loss)	$ 10,865	$ (140,123)	$ 284,229
Add back:			
Amortization of deferred costs (1)	91,763	80,984	48,809
Amortization of deferred costs for rigs under Operating Agreements (1)	-	-	153
Depreciation (2)	71,780	87,421	81,711
Loss on impairment of assets	47,094	271,469	-
Interest expense and financing charges, net of interest income (3)	40,814	41,282	50,159
Income tax expense (4)	19,757	30,373	43,032
Income tax expense for rigs under Operating Agreements (4)	-	-	8,307
Severance costs (5)	4,786	-	-
Loss on disposal of assets	4,826	11,299	2,921
Sponsors' fee (6)	4,500	4,500	4,500
Exclusion of non-income tax related costs (7)	699	(769)	2,940
Share-based compensation expense, net of forfeitures (8)	179	638	1,981
Rig preparation and relocation costs (9)	-	6,448	-
Rig reactivation costs (10)	-	4,185	37,233
Rig inventory acquisition costs (11)	-	59	4,018
Start-up costs (12)	-	-	2,873
Gain on insurance recovery (13)	-	(25,432)	-
Amortization of drilling contract intangibles (14)	-	(983)	(31,522)
Others (15)	(1,507)	872	(95)
Adjusted EBITDA	$ 295,556	$ 372,223	$ 541,249

(1) “Amortization of deferred costs” represents the amortization of deferred costs such as periodic surveys, underwater inspections, contract preparation, mobilization, and major overhauls over the expected benefit period of the expenditure.

(2) “Depreciation” represents the depreciation of property, equipment and rig inventory over its estimated useful life.

(3) ‘‘Interest expense and financing charges, net of interest income” represents interest expenses incurred and accrued on the Company’s debt and the amortization of debt issuance fees and costs over the term of the debt net of capitalized interest and interest income.

(4) “Income tax expense” comprises income tax expense incurred by the Company and income tax expense incurred by rigs operated by Transocean under Operating Agreements which are netted against revenue generated from those operations.

(5) “Severance costs” represents one time employee termination costs.

(6) “Sponsors’ fee” represents the fee to the sponsors in respect of their role as advisors to the Company.

(7) “Exclusion of non-income tax related costs” represents certain charges incurred by the Company whereby a fee of a percentage of an Egyptian entity’s consolidated revenues is levied bi-annually by the Egyptian General Authority for Investment. For U.S. GAAP reporting purposes the Company recognizes these costs as operating and maintenance expenses.

(8) “Share-based compensation expense, net of forfeitures” represents the net amount charged to income related to compensatory stock awards made to certain employees.

(9) “Rig preparation and relocation costs” correspond to the one-time costs incurred in relation to a rig which was mobilized in replacement of a rig which became non-operational following a fire incident in 2015 and which was declared Total Constructive Loss by the Company’s insurance underwriters.

(10) “Rig reactivation costs” represents the expenditure accounted for as operating expense in accordance with U.S. GAAP incurred by the Company on the re-activation of stacked rigs.

(11) “Rig inventory acquisition costs” represents the incremental difference between the amounts provisioned at the time of Acquisition for rig inventory relating to the acquired rigs which Transocean operated for a transitional period of time, and the amounts subsequently settled when operation of these rigs transitioned to the Company.

(12) “Start-up costs” represent costs incurred by the Company including costs accounted for as operating costs for the development and implementation of the Company’s own IT infrastructure, ERP system and other applications; set up costs of new legal entities and offices/infrastructure in the countries where the Company operates; development and set-up costs of the Company’s corporate headquarters and other costs associated with the start-up of the Company. No further start-up costs were charged to the Company’s operations starting 2015.

(13) “Gain on insurance recovery” corresponds to the realized one-time net gain resulting from insurance proceeds for a rig that was declared by the Company’s insurance underwriters in 2015 as Constructive Total Loss following a fire incident.

(14) “Amortization of drilling contract intangibles” represents the net amortization charge of intangible assets and liabilities recognized by the Company as of the acquisition date relating to the acquired drilling service contracts.

(15) “Others” represents currency exchange gain or loss, other income and expense, and other non-recurring items.

“Adjusted EBITDA” as used herein represents net income plus net interest expense and financing charges, net of interest income, income tax expenses, depreciation, amortization of drilling contract intangibles, amortization of deferred costs, share-based compensation expense, sponsors’ fees, rig reactivation costs, rig inventory acquisition costs, exclusion of non-income tax related costs, start-up costs, one-off rig preparation and relocation costs to replace a rig severely impacted by a fire, gain on insurance recovery, gain or loss related to retirement or disposal of assets, loss on impairment of assets and other items. Adjusted EBITDA, as defined, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDA should not be considered in isolation or as a substitute for operating income, net income, other income or cash flow statements data prepared in accordance with U.S. GAAP.

Management believes that Adjusted EBITDA is useful because it is widely used by investors in the Company’s industry to measure a company’s operating performance without regard to items such as interest expense / (income), income tax expense (benefit), depreciation and amortization and non-recurring expenses (benefits), which can vary substantially from company to company, and is also useful to an investor in evaluating the performance of the business. Adjusted EBITDA has significant limitations, including that it does not reflect the Company’s cash requirements for capital or deferred costs, contractual commitments, taxes, working capital or debt service.

Management uses and expects to use Adjusted EBITDA in presentations to the Company's Board of Directors to enable it to have the same consistent measurement basis of operating performance used by Management, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with its equity holders, lenders, note holders, rating agencies and others, concerning the Company's financial performance.

Liquidity and Capital Resources

Sources of liquidity

The Company had $113.1 million and $115.7 million in cash and cash equivalents as at December 31, 2016 and December 31, 2015, respectively. Our sources of liquidity principally consisted of cash balances in banks, cash generated from operations, availability under the SDHL Revolver and the Newbuild sale and leaseback financing facility. Our primary uses of cash were dividend distributions to the parent, capital expenditures and deferred costs payments, and interest and income tax payments. As at December 31, 2016 and 2015, there were $28.5 million and $48.3 million of surety bonds issued under the SDHL Revolver, respectively. In addition, there were no cash borrowings under the facility during the same periods.

At any given time, we may require a significant portion of cash on hand and amounts available under the SDHL Revolver for working capital and other needs related to the operation of our business. The Company believes it will have adequate liquidity to fund its operations over the next twelve months.

Detailed explanations of our liquidity and capital resources for the years ended December 31, 2016 and 2015 are given below.

Discussion of Cash flows

The following table sets out certain information regarding the Company's cash flow statements for the years ended December 31, 2016, 2015 and 2014:

	Years ended December 31,		
	2016	2015	2014
	(In thousands)		
Net cash provided by operating activites before changes in operating assets and liabilities	$ 207,230	$ 338,536	$ 383,927
Changes in operating assets and liabilites			
Intercompany receivables	(4,074)	(440)	(19,820)
Other operating assets and liabilities, net	23,193	(7,420)	54,196
Net cash provided by operating activities	226,349	330,676	418,303
Net cash used in investing activities	(91,437)	(269,066)	(315,312)
Net cash used in financing activities	(137,462)	(36,182)	(237,779)
Net (decrease) / increase in cash and cash equivalents	(2,550)	25,428	(134,788)
Cash and cash equivalents at beginning of year	115,656	90,228	225,016
Cash and cash equivalents at end of year	$ 113,106	$ 115,656	$ 90,228

Net cash provided by operating activities

Net cash provided by operating activities decreased to $226.3 million in 2016 from $330.7 million for 2015. The decrease of $104.4 million was primarily driven by the variance of the current year results of operations compared to last year. See "Results of Operations".

During the years ended December 31, 2016 and 2015, the Company made cash payments of $37.4 million and $33.4 million in interest net of interest amounts capitalized of $10.7 million and $8.7 million in relation to our Newbuilds rig construction, respectively, included under "other operating assets and liabilities, net".

The Company also made cash payments of $26.1 million and $40.7 million in income taxes included under "other operating assets and liabilities, net" during the years ended December 31, 2016 and 2015, respectively.

Net cash used in investing activities

Net cash used for investing activities for 2016 totaled $91.4 million compared to $269.1 million in 2015. Our primary uses of cash in investing activities for 2016 included $53.5 million for the construction, enhancement and other improvement of our drilling rigs, $55.8 million for deferred costs and $421 thousand increase in restricted cash. This was partially offset by the $16.9 million paid by the Lessor to the Company for costs incurred on a newbuild rig and $1.5 million proceeds from disposal of property and equipment.

Cash used for capital expenditures, including capitalized interest, amounted to $53.5 million for 2016 and $157.2 million in 2015. The decrease of $103.7 million was mainly due to $18.5 million milestone payments made by the Company in 2015 related to the Newbuilds, lower expenditures on rig reactivation activity, and reduced capital spending across the fleet in the current year.

As part of the sale and leaseback transactions, contractual commitment payments totaling $148.1 million and $55.5 million were paid by the third party financial institutions directly to the shipyard constructing the rigs and $6.2 million and $643 thousand was recorded as capitalized interest and obligations under sale and leaseback. Therefore, these non-cash transactions were not reflected on the consolidated statements of cash flows for the years ended December 31, 2016 and 2015.

Cash payments for deferred costs decreased by $105.8 million from $161.6 million in 2015 to $55.8 million in 2016 mainly as fewer rigs were undergoing contract preparation for new contracts in 2016 compared to 2015. See discussion of these expenditures below in “Capital expenditures and deferred costs”.

Capital expenditures and deferred costs

Capital expenditures and deferred costs include fixed asset purchases, investments associated with the construction of newbuild rigs and certain expenditures associated with regulatory inspections, major equipment overhauls, contract preparation, including rig upgrades, mobilization and stacked rig reactivations. Capital expenditures and deferred costs can vary from period over period depending upon the requirements of existing and new customers, the number and scope of out-of-service projects, the timing of regulatory surveys and inspections, and the number of rig reactivations. Capital additions are included in property and equipment and are depreciated over the estimated remaining useful life of the assets. Deferred costs are included in other current assets and other assets on the balance sheet and are amortized over the relevant periods covering either: (i) the underlying firm contractual period to which the expenditures relate, or; (ii) the period until the next planned similar expenditure is to be made.

The following table sets out the Company’s capital expenditures and deferred costs for the year ended December 31, 2016, 2015 and 2014:

	Years ended December 31, 2016	2015	2014
	(In thousands)		
Regulatory and maintenance (1)	$ 37,960	$ 127,695	$ 120,352
Contract preparation (2)	22,353	65,232	46,551
Fleet spares and other (3)	6,964	11,646	25,670
Reactivation projects (4)	-	23,372	64,524
	67,277	227,945	257,097
Newbuilds (5)	190,035	95,254	76,237
Total capital expenditures and deferred costs	$ 257,312	$ 323,199	$ 333,334

(1) Includes major overhauls, regulatory costs, general upgrades and sustaining capital expenditures on rigs in operation.

(2) Includes specific upgrade, mobilization and preparation costs associated with a customer contract. It excludes contract preparation costs associated with reactivation projects (such amounts are included under “Reactivation projects”).

(3) Includes (i) acquisition and certification costs for the rig fleet spares pool which is allocated to specific rig expenditure as and when required by that rig which will result in an expenditure charge to that rig and a credit to Fleet spares and (ii) office and infrastructure expenditure.

(4) Includes all capital expenditures and deferred costs associated with reactivation projects including regulatory and maintenance, and contract preparation.

(5) Includes all payments made under the construction contracts with Lamprell shipyard for the two newbuild jackup rigs, internal costs associated with project management, machinery and equipment provided to the project by the Company and capitalized interest.

The following table reconciles the cash payments related to additions to property and equipment and deferred costs to the total capital expenditures and deferred costs:

	Years ended December 31,		
	2016	2015	2014
		(In thousands)	
Cash payments for additions to property and equipment	$ 53,541	$ 157,193	$ 168,404
Net change in accrued but unpaid additions to property and equipment	(5,080)	(60,034)	23,004
	$ 48,461	$ 97,159	$ 191,408
Add: Asset addition related to sale and leaseback transactions	154,306	74,703	-
Total capital expenditures	$ 202,767	$ 171,862	$ 191,408
Cash payments for additions to deferred costs	$ 55,845	$ 161,553	$ 147,752
Net change in accrued but unpaid additions to deferred costs	(1,300)	(10,216)	(5,826)
Total deferred costs	$ 54,545	$ 151,337	$ 141,926
Total capital expenditures and deferred costs	$ 257,312	$ 323,199	$ 333,334

Net cash used in financing activities

The Company paid $135.6 million and $35.6 million in dividend to its parent during the years ended December 31, 2016 and 2015, respectively. The dividends paid to its parent include amounts used to settle the bi-annual interests on its loan during the years ended December 31, 2016 and 2015, respectively.

In addition, there were $1.8 million and $591 thousand of net cash used during the years ended December 31, 2016 and 2015, respectively. In 2016, the Company made rental payments including interest of $1.8 million to the Lessor for the newbuild rig held under capital lease. In 2015, there were $551 thousand payments for debt issuance costs and $40 thousand payments for the repurchase of shares under the parent share based compensation plan.

Indebtedness

At December 31, 2016, the Company's indebtedness of $711.6 million included: (1) $466.9 million of 8.625% Senior Secured Notes due November 1, 2018; and (2) $244.7 million obligations under the sale and leaseback agreements.

8.625% Senior Secured Notes

During the year, the company was in the process to modify the terms of its 8.625% Senior Secured Notes with the exchange of $444.585 million at 100% redemption price. At December 31, 2016, the costs incurred for this debt restructuring were capitalized as prepaid expense. On January 12, 2017, the Company successfully concluded the refinancing of its debt facilities. Accordingly, all costs to support this transaction including the incentive fee to the noteholders of $5.7 million will be recognized in the next reporting period. See *Note 24 – Subsequent Events* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

Obligations under sale and leaseback

On October 10, 2015, certain wholly owned subsidiaries of the Company whose assets consist solely of the two under construction fit-for-purpose new build jackup rigs entered into a combined minimum of $296.2 million and maximum of $330.0 million sale and leaseback financing transactions with the Lessor which are wholly owned subsidiaries of Industrial and Commercial Bank of China Leasing. In connection with these transactions, the Company executed Bareboat Charter agreements with the Lessor to operate the Newbuilds after 90 days of expected delivery dates for a period of 5 years to execute the two drilling services contracts with Chevron Thailand.

On December 1, 2016, after the Company took delivery of one of the Newbuilds and following the completion of final customer acceptance requirements, the rig commenced its five-year contract with Chevron. The second rig is still under construction and is expected to be delivered during the second quarter of 2017.

The outstanding balance of obligations under sale and leaseback is $244.7 million and $74.7 million as of December 31, 2016 and 2015, respectively. The current year balance consists of $16.0 million, which represents the scheduled monthly principal installments for the newbuild rig which commenced its drilling contract and capital lease on December 1, 2016, and $228.7 million as long term obligations. The long term obligations include $152.0 million for the newbuild rig under capital lease and $76.7 million for the newbuild rig still under construction. The prior year balance of $74.7 million represented the long term obligations for the newbuilds under construction.

SDHL Revolving Credit Facility

At December 31, 2016, there was no cash drawdown and $28.5 million of surety bonds were outstanding on the SDHL Revolver. On January 12, 2017, the Company successfully amended the terms of the SDHL Revolver.

See *Note 24 – Subsequent Events* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

See also *Note 10 – Debt and Note 11 – Sale and Leaseback* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

Contractual Obligations

As of December 31, 2016, the Company's contractual obligations were as follows:

	Years ending December 31,						
	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
	(In thousands)						
Debt repayment (1)	$ -	$ 475,000	$ -	$ -	$ -	$ -	$ 475,000
Interest on debt (2)	44,407	35,535	-	-	-	-	79,942
Sale and lease back obligations (3)	37,379	52,082	50,946	49,387	129,337	93,705	412,836
Operating leases	6,367	4,207	474	189	82	-	11,319
Total	$ 88,153	$ 566,824	$ 51,420	$ 49,576	$ 129,419	$ 93,705	$ 979,097

(1) Debt consists of 8.625% Senior Secured Notes.

(2) Assuming no change in the current variable interest rate applied. Includes commitment fees on the SDHL Revolver assuming that the undrawn balance stays the same as of December 31, 2016.

(3) This represents minimum annual rental payments and Purchase Obligation Price assuming estimated average interest rates pursuant to the sale and leaseback transactions as of December 31, 2016.

Other Commercial Commitments

We have other commercial commitments which contractually obligate us to settle with cash under certain circumstances. Surety bonds and parent company guarantees entered into between certain customers and governmental bodies guarantee the Company's performance regarding certain drilling contracts, customs import duties and other obligations in various jurisdictions.

The Company has surety bond facilities in either U.S. dollars or local currencies of approximately $85.0 million provided by several banks to guarantee various contractual, performance, and customs obligations. The Company entered into these facilities in India, Egypt, UAE and Nigeria. The outstanding surety bonds were $33.3 million and $64.2 million at December 31, 2016 and 2015 (including $7.8 million surety bonds for which the credit facility was not in place which were secured by 100% cash deposits in 2015), respectively.

In addition, the Company had outstanding bank guarantees and performance bonds amounting to $28.5 million and $48.3 million as of December 31, 2016 and 2015, respectively, against the $200 million SDHL Revolver.

Therefore, the total outstanding bank guarantees and surety bonds issued by the Company were $61.8 million and $112.5 million as of December 31, 2016 and 2015, respectively.

Under the terms of the Acquisition, the Seller agreed to continue to provide financial support by maintaining letters of credit, surety bonds and other performance and obligation guarantees. This agreement with the Seller to provide financial support expired on November 30, 2015. The Seller did not issue any new letter of credits, surety bonds and other performance and obligation guarantees after November 30, 2015. All outstanding surety bonds provided by the Seller on the Company's behalf of $23.7 million as of December 31, 2015 were cleared and replaced by the Company's issued surety bonds in 2016.

At December 31, 2016, these obligations stated in U.S. dollar equivalent and their times to expiration were as follows:

	Years ending December 31,					
	2017	2018	2019	2020	Thereafter	Total
	(In thousands)					
Surety bonds	$ 46,430	$ 4,531	$ 10,863	$ -	$ -	$ 61,824

Off Balance Sheet Arrangements

Contingent liabilities

As of December 31, 2016, we are not exposed to any contingent liabilities that will result in a material adverse effect on the current consolidated financial position, results of operations or cash flows. The majority of the contingent liabilities that we are exposed to, relate to legal and tax cases, which are fully indemnified by Transocean. See financial information for the Company set out in "Item 8. Financial Statements and Supplementary Data" in *Note 9 - Income Taxes* and *Note 13 - Commitments and Contingencies*.

Derivative Instruments

The Board has approved policies and procedures for derivative instruments that require the approval of our Chief Financial Officer prior to entering into any derivative instruments. From time to time, we may choose to enter into a variety of derivative instruments in connection with the management of our exposure to fluctuations in interest rates and currency exchange rates. We do not enter into derivative transactions for speculative purposes; however, we may enter into certain transactions that do not meet the criteria for hedge accounting.

Off Balance Sheet Financing

We had no off balance sheet financings during the years ended December 31, 2016 and December 31, 2015.

Critical Accounting Policies, Key Judgments and Estimates

The Company's significant accounting policies are included in *Note 2- Significant Accounting Policies* in our consolidated financial statements. In the preparation of the financial statements, we are required to make estimates and judgments that affect the amounts reported in our consolidated financial statements and related disclosures. On an ongoing basis, we evaluate these estimates, including those related to allowance for doubtful accounts, property and equipment, goodwill and other intangible assets, income taxes, other post-retirement benefits and contingencies. We base our estimates on various assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

We identify our critical accounting policies as those that are significant to our results of operations, financial condition and cash flows and that require management's most difficult, subjective or complex judgements in matters that are inherently uncertain. We believe that our more critical accounting policies include revenue recognition, property and equipment, operating and deferred costs, share-based compensation, derivative financial instruments and fair value.

Revenue recognition

We account for our dayrate, recharges, bonuses and other miscellaneous revenue on an earned basis. Mobilization fees and capital or upgrade reimbursements recorded at the commencement of a specific contract are deferred and amortized over the firm contract period. The firm contract period of the contract excludes contract extension options. Occasionally our contracts may be based on the number of wells drilled rather than a specified contract term. In these cases such amortization periods will reflect an estimate of the time required to fulfill the contract obligations. Upon completion of drilling contracts, any demobilization fees are immediately recognized as revenue when collectability is reasonably assured. Revenues for Company owned rigs operated by Transocean for a period of time from the date of Acquisition to when the rigs became operated by the Company were accounted for as net revenue after deducting the rig operating costs, the fixed per day per rig onshore support fee, the fixed per day per rig corporate services fee and taxes. Upon transfer of the operations of these rigs to us, the revenue and costs are accounted for on a gross basis. Drilling contracts acquired at Acquisition were subject to fair market valuation by applying independent estimates of the market dayrates that were available for similar contracts at the date of Acquisition. The fair value adjustments for these existing drilling contracts were recognized in drilling contract intangible assets and liabilities and were amortized over the remaining period of the drilling contract from the date of Acquisition.

Property and Equipment

Property and equipment is stated at fair market value as of the date of the Acquisition and at adjusted fair market value after adjustment for any impairment. Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the estimated useful lives of the assets. The remaining estimated average useful life of existing drilling rigs in the Company's fleet is 10 years and salvage values are generally estimated at 10% of capitalized costs.

We evaluate property and equipment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. An impairment loss on property and equipment exists when the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition is less than its carrying amount. Any actual impairment loss recognized represents the excess of the asset's carrying value over the estimated fair value. The Company estimates the fair values of property and equipment by applying a combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date.

Operating and deferred costs

Rig operating costs are accrued as and when incurred. Any payments in advance for goods and services such as office rent, insurance premiums and expatriate housing rent are deferred and charged to expenses in the period in which the goods were received or the service was provided.

Rigs and rig inventory at the date of Acquisition were accounted for at fair value and are being depreciated over the remaining useful life of the rig less salvage value. The purchases of inventory are expensed as the impact on the consolidated statements of operations is broadly commensurate with the expense that would have been recorded had inventory been separately recorded on the consolidated balance sheets.

Rig project costs are either capitalized, deferred or accounted for as operating costs depending upon the type of expenditure being incurred. In general expenditures which increase the functionality of the rig are capitalized; expenditures on regulatory surveys and underwater inspections are deferred and amortized over the time period until the next survey or inspection; expenditures for major overhauls are deferred and amortized over the time period until the next major overhaul; expenditures for contract preparation and mobilization are deferred and amortized over the firm contract period. Demobilization costs are expensed as incurred.

Share-based Compensation

Share-based payments (to the extent they are compensatory) are recognized in the consolidated statements of operations based on their fair values and the estimated number of shares or units that are ultimately expected to vest. For awards which vest based on service conditions, the value of the portion of the award that is ultimately expected to vest is recognized as an expense over the five year vesting period. For awards which vest only after an exit event or Initial Public Offering ("IPO"), compensation expense is recognized upon the occurrence of the event.

Derivative Financial Instruments

The Company's derivative financial instruments consist of forex contracts which the Company may designate as cash flow hedges. In accordance with U.S. GAAP, each derivative contract is stated in the balance sheet at fair value with gains and losses reflected in the consolidated statements of operations except that, to the extent the derivative qualifies for and is designated as an accounting hedge, the gains and losses are reflected in income in the same period as offsetting gains and losses on the qualifying hedged positions. Designated hedges are expected to be highly effective, and therefore, adjustments to record the carrying value of the effective portion of the derivative financial instruments to their fair value are recorded as a component of accumulated other comprehensive income / (loss) ("AOCIL"), in the consolidated balance sheets. The effective portion of the cash flow hedge will remain in AOCIL until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or it is determined that the hedged transaction will not occur. The Company reports such realized gains and losses as a component of operating and maintenance expenses in the consolidated statements of operations to offset the impact of foreign currency fluctuations of the expenditures in local currencies in the countries in which the Company operates. Derivatives with asset fair values and derivatives with liability fair values are reported in other current assets or other assets and other current liabilities or other long-term liabilities, respectively, on the consolidated balance sheets depending on their maturity date.

Fair value measurements

Fair value is estimated at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Fair value measurements are based on a hierarchy which prioritizes valuation technique inputs into three levels. The fair value hierarchy is composed of: (i) Level 1 measurements, which are fair value measurements using quoted unadjusted market prices in active markets for identical assets or liabilities; (ii) Level 2 measurements, which are fair value measurements using inputs, other than Level 1 inputs, which are directly or indirectly observable for the asset or liability and; (iii) Level 3 measurements, which are fair value measurements which use unobservable inputs. The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

Recently Issued and Recently Adopted Accounting Standards

See *Note 3 - New Accounting Pronouncements* to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

Item 7A. Quantitative and Qualitative Disclosures About Market Risks

We are exposed to market risk from changes in interest rates, currency exchange rate, and credit as follows:

Interest Rate Risk

The Company is exposed to interest rate risk related to the fixed rate debt under the 8.625% Senior Secured Notes and variable rate debts under the SDHL Revolver and the obligations under the sale and leaseback agreements. Fixed rate debt, where the interest rate is fixed over the life of the instrument and the instrument's maturity is greater than one year, exposes the Company to changes in market interest rates if and when maturing debt is refinanced with new debt. The variable rate debt, where the interest rate may be adjusted frequently over the life of the debt, exposes the Company to short-term changes in market interest rates.

At December 31, 2016, the outstanding balance of our obligations under the sale and leaseback agreements was $244.7 million which in total represents 34.4% of our total debt. Based upon variable-rate debt balances outstanding as of December 31, 2016, a hypothetical one percentage point change in annual interest rates could result in a corresponding change in annual interest expense of approximately $2.4 million.

Foreign Currency Risk

Our international operations expose us to currency exchange rate risk. This risk is primarily associated with compensation costs of employees and purchasing costs from non-U.S. suppliers, which are denominated in currencies other than the U.S. dollar. We do not have any non-U.S. dollar debt and thus are not exposed to currency risk related to debt.

Our primary currency exchange rate risk management strategy involves structuring certain customer contracts to provide for payment from the customer in both U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. Due to various factors, including customer acceptance, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual local currency needs may vary from those anticipated in the customer contracts, resulting in partial exposure to currency exchange rate risk. The currency exchange effect resulting from our international operations has not historically had a material impact on our operating results.

Credit Risk

Our financial instruments that potentially subject us to concentrations of credit risk are cash and cash equivalents and accounts receivables.

We generally maintain cash and cash equivalents at commercial banks with high credit ratings.

Our trade receivables are with a variety of government owned or controlled energy companies, publicly listed integrated oil companies or independent exploration and production companies. We perform ongoing credit evaluations of our customers, and generally do not require material collateral. The Company may from time to time require its customers to issue bank guarantee in its favor to cover non-payment under drilling contracts.

An allowance for doubtful accounts is established on a case-by-case basis, considering changes in the financial position of a customer, when it is believed that the required payment of specific amounts owed is unlikely to occur. At December 31, 2016 and 2015, the allowance for doubtful accounts was $99.6 million and $110.2 million, respectively.

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements as at December 31, 2016 can be found in the Exhibits section pages F-1 to F-35.

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

None

Item 9A. Controls and Procedures

The credit agreements provide an exemption to reporting this Item.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Items normally elected to be included in the annual Proxy Statement have been deemed so elected for these purposes; such as “Election of Directors,” “Additional Information Regarding the Board of Directors,” Section 16(a) Beneficial Ownership Reporting Compliance,” “Annual General Meeting” and “Other Matters” the annual general meeting and reporting under Section 16 (a) of the 1934, and are deemed as being incorporated in this report by reference.

Executive Officers

The following table sets forth information concerning our executive officers and directors, including their ages, as of December 31, 2016:

Name	Age as of December 31, 2016	Position
David Mullen	58	Chief Executive Officer
Kurt Hoffman	56	Chief Operating Officer
Greg O' Brien	30	Executive Vice President and Chief Financial Officer
Ian Clark	57	Executive Vice President
Dzul Bakar	50	Vice President and General Counsel
Simon Rushton	56	Vice President, Operations
Jean Hahusseau	59	Vice President, Human Resources
Michael Mezzina	46	Vice President and Controller
Ramy Danial	39	Vice President, Tax and Treasury

David Mullen, Chief Executive Officer

Mr. Mullen has over 30 years’ experience in the oil services business. From September 2010 to April 2011, Mr. Mullen was CEO of Wellstream Holdings PLC, a UK listed company that designed and manufactured subsea pipeline products and included as part of the product offering, subsea services and installation. From April 2008 to August 2010, Mr. Mullen served as Chief Executive Officer of Ocean Rig ASA, a Norwegian listed ultra-deep water drilling contractor. Prior to Ocean Rig ASA, Mr. Mullen also spent four years as a senior leader of the world’s largest offshore drilling company, Transocean. As Senior Vice President of Global Marketing, Business Development and M&A at Transocean, Mr. Mullen spearheaded marketing and strategic planning. Mr. Mullen had a 23-year career at Schlumberger, including as President of Oilfield Services for North and South America. Mr. Mullen received a B.A. in Geology & Physics from Trinity College Dublin and an M.S. degree in Geophysics from University College Galway.

Kurt Hoffman, Executive Vice President and Chief Operating Officer

Mr. Hoffman has worked on rigs around the world and has over 30 years’ experience in the global oil and gas contract drilling industry. Prior to joining Shelf Drilling, from August 2009 to April 2011, Mr. Hoffman was Senior Vice President and Chief Operating Officer of Seahawk Drilling, a Houston and Gulf of Mexico-based jackup drilling provider where he was responsible for the company’s daily operations and strategic business plan implementation. From 1991 through August 2009, Mr. Hoffman spent 18 years with Noble Corporation where he held senior operational and executive roles, including Vice President of Worldwide Marketing, Vice President of Western Hemisphere Operations and President of Noble’s engineering services divisions, Triton Engineering Services. Mr. Hoffman received a B.S. degree from Southwest Texas State University.

Greg O’Brien, Executive Vice President and Chief Financial Officer

Mr. O’Brien is the Executive Vice President and Chief Financial Officer since March 2016 in replacement of Mr. Andrew Roberts who retired from the Company. Prior to his current role, Mr. O’Brien served in Shelf Drilling as Director, Strategic Planning since 2014, in charge of Shelf Drilling’s corporate development efforts. Mr. O’Brien joined Shelf Drilling from Lime Rock Partners, where he focused on oilfield services and Exploration & Production investment opportunities internationally. Before that, Mr. O’Brien held energy investment banking roles with J.P. Morgan and SunTrust Robinson Humphrey. Mr. O’Brien is a graduate of the McIntire School of Commerce at the University of Virginia.

Ian Clark, Executive Vice President

Mr. Clark has over 30 years' experience in the oil services business. Prior to joining Shelf Drilling, Mr. Clark spent 12 years with Transocean where he most recently served as Vice President of Human Resources and as part of its senior management team. Previous roles included Division Manager for Transocean's operations in North East Asia and also Managing Director for Nigeria. Before joining Transocean, Mr. Clark had a 20-year career with Schlumberger in various managerial, technical and marketing roles across Europe and Africa. Mr. Clark has a B.S. degree in Electrical and Electronic Engineering from Heriot Watt University in Edinburgh, Scotland and completed the Advanced Management Program at Harvard Business School.

Other key members of Shelf Drilling's management team include the following:

Dzul Bakar, Vice President and General Counsel

Previously, Mr. Bakar served in a similar role as Associate General Counsel at Transocean from April 2001 until the Acquisition, where he assumed various legal, governance, compliance and operational responsibilities. Mr. Bakar has a strong background in international operations with over 17 years' experience covering the United States, Caspian Sea, Middle East, and Asia. Prior to joining Transocean, Mr. Bakar spent six years at Schlumberger from February 1995 to April 2001 in a variety of legal roles of increasing responsibilities with postings in Singapore, Jakarta and Houston. At the beginning of his career, Mr. Bakar also practiced as an advocate and solicitor at a leading Malaysian law firm. Mr. Bakar holds a combined degree in Economics and Law from the University of Tasmania and in 2011 completed an executive Management Acceleration Program at INSEAD Business School.

Simon Rushton, Vice President, Operations

Mr. Rushton is Vice President, Operations at Shelf Drilling and joined the Company after spending his entire working life at Transocean. In a 29-year career, Mr. Rushton has held a wide variety of key operational roles at Transocean, culminating in his last position as General Manager of the Mediterranean (MED) Division, based in Cairo. Other Transocean roles include General Manager of the Far East and Australia (FEA) division, Director of Asset Management, and a number of positions as Division Manager, Operations Manager and Rig Manager in Asia, North America, South America, Europe and the Middle East. Mr. Rushton has a B.Sc. degree in Mechanical Engineering from the University of Houston.

Jean Hahusseau, Vice President, Human Resources

Mr. Hahusseau is Vice President, Human Resources at Shelf Drilling. Mr. Hahusseau has more than 30 years' experience with Transocean, starting as a trainee engineer in 1982 towards his most recent position as Director of Total Rewards for Transocean prior to joining Shelf Drilling. At Transocean, Mr. Hahusseau occupied various operational positions, such as rig manager and district manager in West Africa, Middle East and Asia as well as safety manager for Europe & Africa. Mr. Hahusseau was also Director of Human Resources for the Europe & Africa Unit before taking up his post as Director of Total Rewards. Mr. Hahusseau graduated from the École d'Ingénieurs en Construction Aéronautique in Toulouse, France.

Michael Mezzina, Vice President and Controller

Mr. Mezzina is Vice President and Controller at Shelf Drilling. Prior to joining Shelf Drilling, Mr. Mezzina held the role of Global Finance Director at Transocean, financially overseeing the worldwide operations of the company. Mr. Mezzina worked at Transocean for over 16 years and has a wide range of accounting and finance experience, where he served in different capacities of increasing responsibilities. This included the positions of Division Controller, Business Unit Controller and Director of Accounting, Corporate, with postings in West Africa, Europe, Egypt and the United States. Mr. Mezzina graduated from the Normandy Business School, France, with a Master's degree in Finance.

Ramy Danial, Vice President, Tax and Treasury

Mr. Danial is Vice President of Tax and Treasury at Shelf Drilling. Prior to joining the Company, he was the Head of Tax at Parker Drilling in Houston, Texas, where he directed all aspects of worldwide taxation. He began his career as an international tax consultant with the public accounting firm PricewaterhouseCoopers and brings over 15 years of experience in global tax matters, internal controls and compliance with Sarbanes-Oxley. Mr. Danial has held various tax leadership positions at Weatherford, Pride International and Kimberly-Clark. He holds a Bachelor's degree in Accounting from John Carroll University in Cleveland, Ohio and is a Certified Public Accountant.

Item 11. Executive Compensation

The credit agreements provide an exemption to reporting this Item.

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

Items normally elected to be included in the annual Proxy Statement have been deemed so elected for these purposes: “Equity Compensation Plan Information”, “Security Ownership of Certain Beneficial Owners” and “Security Ownership of Management”.

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

Items normally elected to be included in the annual Proxy Statement have been deemed so elected for these purposes; see *Note 21 – Related Parties* for information regarding related party transactions in the notes to consolidated financial statements in Part IV.

Item 14. Principal Accounting Fee and Services

Fees for audit services and related expenses from PricewaterhouseCoopers totaled $370 thousand, $467 thousand and $206 thousand in 2016, 2015, and 2014 respectively. Fees for tax and other services from PricewaterhouseCoopers totaled $525 thousand, $465 thousand and $646 thousand in 2016, 2015 and 2014, respectively.

Part IV

Item 15. Exhibits

Financial Statements pages F-1 to F-35.

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2016
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Independent Auditor's Report

To the Board of Directors

We have audited the accompanying consolidated financial statements of Shelf Drilling Holdings, Ltd. and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2016 and December 31, 2015, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for the years ended December 31, 2016, 2015 and 2014.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Shelf Drilling Holdings, Ltd. and its subsidiaries at December 31, 2016 and December 31, 2015, and the results of their operations and their cash flows for the years ended December 31, 2016, 2015 and 2014 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers

Dubai, United Arab Emirates
February 28, 2017

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Douglas O'Mahony, Paul Suddaby, Jacques Fakhoury and Mohamed ElBorno are registered as practising auditors with the UAE Ministry of Economy

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	Years ended December 31,		
	2016	2015	2014
Revenues			
Operating revenues	$ 668,649	$ 1,012,757	$ 1,213,700
Amortization of drilling contract intangibles	-	983	31,522
Other operating revenue	15,668	17,558	20,804
	684,317	1,031,298	1,266,026
Operating costs and expenses			
Operating and maintenance	354,095	534,156	667,162
Depreciation	71,780	87,421	81,711
Amortization of deferred costs	91,763	80,984	48,809
General and administrative	44,845	138,996	87,674
	562,483	841,557	885,356
Gain on insurance recovery	-	25,432	-
Loss on impairment of assets	(47,094)	(271,469)	-
Loss on disposal of assets	(4,826)	(11,299)	(2,921)
Operating income / (loss)	69,914	(67,595)	377,749
Other (expense) / income, net			
Interest income	356	102	21
Interest expense and financing charges	(41,170)	(41,384)	(50,180)
Other, net	1,522	(873)	(329)
	(39,292)	(42,155)	(50,488)
Income / (loss) before income taxes	30,622	(109,750)	327,261
Income tax expense	19,757	30,373	43,032
Net income / (loss)	$ 10,865	$ (140,123)	$ 284,229

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

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Years ended December 31,		
	2016	**2015**	**2014**
Net income / (loss)	$ 10,865	$ (140,123)	$ 284,229
Other comprehensive income, net of tax			
Foreign currency forward exchange contracts			
Changes in unrealized gains	427	-	-
Reclassification of net gain from other comprehensive income to net income	(427)	-	-
	$ -	$ -	$ -
Total comprehensive income / (loss)	$ 10,865	$ (140,123)	$ 284,229

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

SHELF DRILLING

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2016	December 31, 2015
Assets		
Cash and cash equivalents	$ 113,106	$ 115,656
Accounts and other receivables, net	171,530	208,253
Other current assets	94,423	118,454
Total current assets	379,059	442,363
Property and equipment	1,326,361	1,175,054
Less accumulated depreciation	295,685	230,421
Property and equipment, net	1,030,676	944,633
Deferred tax assets	3,137	3,697
Other assets	118,441	135,259
Total assets	$ 1,531,313	$ 1,525,952
Liabilities and equity		
Accounts payable	$ 70,159	$ 89,633
Accrued income taxes	-	546
Interest payable	6,828	6,828
Obligations under sale and leaseback	15,977	-
Other current liabilities	32,665	46,672
Total current liabilities	125,629	143,679
Long-term debt	466,857	464,204
Obligations under sale and leaseback	228,728	74,703
Deferred tax liabilities	8,525	8,788
Other long-term liabilities	25,197	33,601
Total long-term liabilities	729,307	581,296
Commitments and contingencies		
Ordinary shares of $0.01 par value; 5,000,000 shares authorized at December 31, 2016 and 2015; one share issued and outstanding at December 31, 2016 and 2015	-	-
Additional paid-in capital	647,787	647,608
Retained earnings	28,590	153,369
Total equity	676,377	800,977
Total liabilities and equity	$ 1,531,313	$ 1,525,952

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

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands, except share data)

	Years ended December 31,			Years ended December 31,		
	2016	2015	2014	2016	2015	2014
	Shares			Amount		
Ordinary shares						
Balance, beginning of year	1	1	1	$ -	$ -	$ -
Balance, end of year	1	1	1	$ -	$ -	$ -
Additional paid-in capital						
Balance, beginning of year				$ 647,608	$ 647,010	$ 645,029
Capital contribution by parent - share-based compensation				179	638	1,981
Repurchase of shares by parent - share-based compensation				-	(40)	-
Balance, end of year				$ 647,787	$ 647,608	$ 647,010
Retained earnings						
Balance, beginning of year				$ 153,369	$ 329,083	$ 201,663
Ordinary shares dividend				(135,644)	(35,591)	(156,809)
Net income / (loss)				10,865	(140,123)	284,229
Balance, end of year				$ 28,590	$ 153,369	$ 329,083
Total equity						
Balance, beginning of year				$ 800,977	$ 976,093	$ 846,692
Capital contribution by parent - share-based compensation				179	638	1,981
Repurchase of shares by parent - share-based compensation				-	(40)	-
Ordinary shares dividend				(135,644)	(35,591)	(156,809)
Total comprehensive income / (loss)				10,865	(140,123)	284,229
Balance, end of year				$ 676,377	$ 800,977	$ 976,093

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

SHELF DRILLING HOLDINGS, LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years ended December 31,		
	2016	2015	2014
Cash flows from operating activities			
Net income / (loss)	$ 10,865	$ (140,123)	$ 284,229
Adjustments to reconcile net income / (loss) to net cash provided by operating activities			
Depreciation	71,780	87,421	81,711
Amortization of deferred costs	91,763	80,984	48,809
Loss on impairment of assets	47,094	271,469	-
Gain on foreign currency forward exchange contracts	(427)	-	-
Gain on insurance recovery	-	(25,432)	-
Amortization of deferred revenue	(23,511)	(41,026)	(33,330)
(Reversal of) / provision for doubtful accounts, net	(401)	87,431	22,600
Amortization of drilling contract intangibles	-	(983)	(31,522)
Capital contribution by parent - share-based compensation	179	638	1,981
Amortization of debt issue costs and discounts	4,338	5,566	10,252
Loss on disposal of assets	4,826	11,299	2,921
Deferred tax expense / (benefit)	297	1,292	(3,724)
Proceeds from settlement of foreign currency forward exchange contracts	427	-	-
Changes in operating assets and liabilities			
Intercompany receivables	(4,074)	(440)	(19,820)
Other operating assets and liabilities, net	23,193	(7,420)	54,196
Net cash provided by operating activities	226,349	330,676	418,303
Cash flows from investing activities			
Additions to property and equipment *	(53,541)	(157,193)	(168,404)
Additions to deferred costs *	(55,845)	(161,553)	(147,752)
Proceeds from disposal of property and equipment	1,490	547	844
Proceeds from sale and leaseback	16,880	18,515	-
Proceeds from insurance recovery	-	45,000	-
Payments of transaction costs for sale and leaseback	-	(7,555)	-
Change in restricted cash	(421)	(6,827)	-
Net cash used in investing activities	(91,437)	(269,066)	(315,312)
Cash flows from financing activities			
Repurchase of shares by parent - share-based compensation	-	(40)	-
Ordinary shares dividend paid	(135,644)	(35,591)	(156,809)
Payments for obligations under sale and leaseback	(1,818)	-	-
Payments to retire long-term debt	-	-	(74,250)
Payments of debt issuance costs	-	(551)	(6,720)
Advanced to related party	-	-	(30,039)
Received from related party	-	-	30,039
Net cash used in financing activities	(137,462)	(36,182)	(237,779)
Net (decrease) / increase in cash and cash equivalents	(2,550)	25,428	(134,788)
Cash and cash equivalents at beginning of year	115,656	90,228	225,016
Cash and cash equivalents at end of year	$ 113,106	$ 115,656	$ 90,228

* See Note 20 – Supplemental Cash Flow Information for a reconciliation of cash payments for additions to property and equipment and deferred costs to total capital expenditures and deferred costs.

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

SHELF DRILLING HOLDINGS, LTD.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Nature of Business

Business

Shelf Drilling Holdings, Ltd ("SDHL") was incorporated on August 24, 2012 ("inception") as a private corporation in the Cayman Islands and is a holding company with no significant operations or assets other than owned interests in its direct and indirect subsidiaries. SDHL and its majority owned subsidiaries (together, the "Company") provide shallow-water drilling services to the oil and natural gas industry. The Company's corporate offices are in Dubai, United Arab Emirates ("UAE"), geographically close to its operations in the Middle East, South East Asia, India, West Africa and the Mediterranean. The Company is 100% owned by Shelf Drilling Intermediate, Ltd ("SDIL"). SDIL is 100% owned by Shelf Drilling Midco, Ltd ("Midco") which is directly owned by Shelf Drilling, Ltd ("SDL"), the ultimate parent company. These direct and indirect parents of the Company (together, the "Parents") are incorporated as private corporations in the Cayman Islands.

SDHL, through its majority and wholly owned subsidiaries, provides safe and reliable fit-for-purpose independent cantilever jackup drilling services. The Company is primarily engaged in development and workover activity on producing assets in shallow water of up to 400 feet in water depth. The Company owns 35 independent cantilever jackup rigs, one swamp barge and one new build jackup under construction.

In May 2014, the Company signed a contract with Lamprell Energy Limited (the "Builder") to construct two new build high specification jackup rigs (the "Newbuilds"). On September 29, 2016, the Company took delivery of one of the Newbuilds from the Builder and on December 1, 2016, the rig commenced a five-year contract with Chevron Thailand Exploration and Production, Ltd ("Chevron"). The second rig under construction is expected to be delivered and to commence a five-year contract with Chevron during the second quarter of 2017. See Note 8 – Property and Equipment and Note 11 – Sale and Leaseback.

Acquisition Related Matters

On September 9, 2012, the Company entered into definitive agreements with Transocean Inc. (the "Seller"), providing for the acquisition (the "Acquisition"), both directly and through the purchase of certain of the Seller's affiliates, of 37 shallow water drilling rigs and one swamp barge (the "business"). The Acquisition closed on November 30, 2012.

Through a number of individual rig operating agreements entered into with the Seller concurrently with the closing of the Acquisition ("Operating Agreements"), the Seller agreed on behalf of the Company to operate, for a transitional period of time, certain rigs acquired by the Company, and to submit invoices and collect revenue from the customers under the associated drilling contracts and pay direct costs and expenses incurred while operating the rigs. Pursuant to the Operating Agreements, the Seller also agreed to transfer the net amount of each drilling contract (customer collections less direct costs and expenses and taxes paid by the Seller) to the Company on a monthly basis. In addition, the Company agreed to pay the Seller a daily pre-determined fixed fee for in country onshore support and a daily fixed fee per rig for corporate services. The Operating Agreements for each individual rig remained in effect until the expiration, novation, or assignment to the Company of the underlying drilling contracts that were in place at the time of the Acquisition, originally resulting in effective terms ranging from 9 months to 27 months. Until the expiration, novation, or assignment of the underlying drilling contracts, the Seller retained possession of the materials and supplies associated with the rigs that the Seller operated under the Operating Agreements. Upon novation, assignment or expiration of the related drilling contracts, the individual rig Operating Agreements were terminated and the Company assumed operation of the rigs. One rig was subject to the Operating Agreements as of December 31, 2014. No rig remained subject to the Operating Agreements as of January 1, 2015.

Under a separate Transition Services Agreement entered into with the Seller concurrently with the closing of the Acquisition, the Seller agreed to provide various corporate and local services to the Company for Company operated rigs. These services were generally provided on a daily fixed fee. The services included use of the Seller's enterprise resource planning ("ERP") system for accounting, fixed assets, treasury, supply chain management, maintenance scheduling, human resource systems, information technology infrastructure and helpdesk support. The Seller agreed to provide certain of these transition services for a period of up to 18 months following the completion of the Acquisition. As of December 31, 2014, all services previously provided under the Transition Services Agreement were assumed by the Company.

To fund the Acquisition, in addition to equity contributions of $645 million from its Parents, SDHL used debt financing. On October 24, 2012, SDHL completed the issuance and sale of $475 million aggregate principal amount of senior secured notes at a coupon rate of 8.625% due November 1, 2018 ("8.625% Senior Secured Notes").

On November 30, 2012, SDHL also entered into a credit agreement, which consisted of a $75 million term loan facility and a $50 million credit facility to issue fully cash collateralized letters of credit. This facility was fully repaid on February 28, 2014 out of existing funds and the credit agreement, along with the associated $50 million cash collateralized letter of credit facility, was cancelled. There were no issued or outstanding letters of credit against the facility at that time.

2016 Events

In April, 2016, the Company sold two stacked rigs, Adriatic V and Adriatic VI. See Note 8 – Property and Equipment.

On December 1, 2016, one of the Newbuilds which is part of the sale and leaseback transactions, commenced a five-year contract with Chevron. See Note 8 – Property and Equipment.

On December 2, 2016, the Company, SDL and Midco, signed an Amended and Restated Transaction Support Agreement with certain equity sponsors of SDL and holders, in the aggregate, of (a) approximately 85.6% of principal amount of the 8.625% Senior Secured Notes and (b) 100% of principal amount of the $350 million term loan of Midco ("Midco Term Loan") to support certain transactions to refinance the Company and Midco debt facilities, subject to terms and conditions. On January 12, 2017, the Company and its Parents successfully concluded the refinancing of the debt facilities. See Note 24 – Subsequent Events.

At December 31, 2016, the Company recorded a non-cash impairment loss of $47.1 million in relation to three rigs out of which one rig was impaired to salvage value. This non-cash impairment was included in loss on impairment of assets in the consolidated statements of operations. See Note 8 – Property and Equipment.

Note 2 — Significant Accounting Policies

Basis of Presentation — The Company has prepared its consolidated financial statements in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). The consolidated financial statements include the Company's accounts, those of the Company's wholly-owned subsidiaries and entities in which the Company holds a controlling financial interest. Entities that meet the criteria for variable interest entities for which the Company is deemed to be the primary beneficiary for accounting purposes are consolidated. As of December 31, 2016, the Company's consolidated financial statements include four joint ventures that meet the definition of variable interest entities. Intercompany transactions and accounts are eliminated in consolidation. The Company applies the equity method of accounting for investments in which it has the ability to exercise significant influence but for which; (i) the entity does not meet the variable interest entity criteria, or; (ii) the entity meets the variable interest entity criteria but the Company is not deemed the primary beneficiary. As of December 31, 2016, none of the Company's investments meet the criteria established for application of the equity method of accounting. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

Accounting Estimates — The preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. As of the date of the Acquisition, the Company used "Hein & Associates LLP", an independent third party expert, to estimate the fair market value of the acquired rigs including inventory and drilling contract intangibles.

On an ongoing basis, these estimates and assumptions are evaluated, including those related to allowance for doubtful accounts, property and equipment, income taxes, other post-retirement benefits and contingencies. The Company bases its estimates and assumptions on various factors that management believes are reasonable, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. While management believes current estimates are appropriate and reasonable, actual results could materially differ from those estimates.

Fair Value Measurements — Fair value is estimated at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Fair value measurements are based on a hierarchy which prioritizes valuation technique inputs into three levels. The fair value hierarchy is composed of: (i) Level 1 measurements, which are fair value measurements using quoted unadjusted market prices in active markets for identical assets or liabilities; (ii) Level 2 measurements, which are fair value measurements using inputs, other than Level 1 inputs, which are directly or indirectly observable for the asset or liability and; (iii) Level 3 measurements, which are fair value measurements which use unobservable inputs. The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

Revenue Recognition — Revenues generated by rigs owned by the Company and operated by the Seller under the Operating Agreements were recorded as net revenue. Net revenue represents the customer revenue less the expenses related to the operation of the rigs (including personnel, asset management and maintenance, operating, miscellaneous and administration expenses), shore based fixed fees, corporate services fixed fee and taxes paid by the Seller. The Company deemed the Seller as the principal regarding the drilling service contracts during the term of the Operating Agreements based on the following:

- The Seller is the contractual primary obligor under the drilling services contracts with customers; and
- The Seller is responsible for fulfillment of drilling services under the contracts subject to the Operating Agreements, including the provision of rigs, rig crew, and all of the related goods and services including general inventory risk.

While the Seller effectively earned no profit under the Operating Agreements and the Company retained the general credit risks, indicating that the Company may be the principal, the Company views the other factors discussed above as more indicative and determined that net revenue presentation was appropriate.

Operating revenues generated by the Company owned and operated rigs under the Transition Services Agreement are recorded on a gross basis. Revenue is recognized when earned and realizable, based on contractual dayrates.

Upon completion of the transition periods related to the Operating Agreements with the Seller, revenue is recognized on a gross basis as earned and realizable, based on contractual dayrates. Amounts earned prior to the beginning of a drilling contract period, such as for mobilization, contract preparation and capital upgrades, are deferred and recognized on a straight-line basis over the primary term of the contract to which they relate. Upon completion of drilling contracts, any demobilization fees are immediately recognized as revenue when collectability is reasonably assured.

Other operating revenue consists of amounts billed for goods and services which are acquired by the Company from other sources and re-billed to customers.

Operating and Deferred Costs — Operating costs are recognized when incurred. Mobilization and demobilization costs of relocating drilling units without contracts are expensed as incurred.

Periodic survey and inspection in lieu of drydock costs incurred in connection with obtaining regulatory certifications to operate the rigs are deferred and amortized on a straight-line basis over the period until the next survey or inspection - generally for periods of between 30 to 60 months. Contract preparation and mobilization expenditures incurred specifically for a rig entering a drilling services contract are deferred and amortized on a straight-line basis over the primary period of the contract to which the costs relate. Periodic major overhauls of equipment are deferred and amortized on a straight-line basis over the period between regularly scheduled overhauls of the same nature.

Foreign Currency — The Company's functional currency is the U.S. dollar. As is customary in the oil and gas industry, the majority of the Company's revenues and expenditures are denominated in U.S. dollar. As such, the Company's exposure to non U.S. dollar denominated currency exchange rate fluctuations is limited. Certain revenues and expenditures incurred by certain subsidiaries are denominated in currencies other than the U.S. dollar. Non U.S. dollar revenues and costs are recorded in U.S. dollars at the prevailing exchange rate as of the date of recognition. Cash receipts and payments made in other currencies are recorded in U.S. dollars at the prevailing exchange rate as of the transaction date. Transaction gains or losses are recorded in net income and include, where applicable, unrealized gains and losses to record the carrying value of foreign currency forward exchange ("forex") contracts not designated as accounting hedges, as well as realized gains and losses from the settlement of such contracts. Monetary assets and liabilities denominated in foreign currency are re-measured to U.S. dollars at the rate of exchange in effect at the end of each month and unrealized exchange gains or losses are recognized in the consolidated statements of operations.

Cash and Cash Equivalents — Cash and cash equivalents is comprised of cash on hand, cash in banks and highly liquid funds with an original maturity of three months or less. Other bank deposits, if any, with maturity of less than a year are classified as short-term bank deposits within other current assets in the consolidated balance sheets. Bank overdrafts, if any, are shown within other current liabilities in the consolidated balance sheets.

Accounts Receivable and Allowance for Doubtful Accounts — Receivables, including accounts receivable, are recorded in the consolidated balance sheets at their nominal amounts less allowance for doubtful accounts. An allowance for doubtful accounts is established on a case-by-case basis, considering changes in the financial position of a customer, when it is believed that the required payment of specific amounts owed is unlikely to occur.

Drilling Contract Intangibles — In connection with the Acquisition, the Company acquired certain existing drilling contracts for future contract drilling services. The terms of these contracts include fixed dayrates that were above or below the market dayrates that were estimated to be available for similar contracts as of the date of the Acquisition. Drilling contract intangibles were recorded as current and non-current assets and liabilities and amortized on a straight-line basis over the respective contract periods.

Property and Equipment — Property and equipment was stated at fair market value as of the date of the Acquisition. Inventory acquired with the business was capitalized as part of the rigs and is maintained at a level to support the operations of the rig. Costs incurred that substantially enhance, improve or increase the useful lives of existing assets are capitalized. Routine expenditures for repairs and maintenance are expensed as incurred.

Construction in progress is stated at cost. Cost consists of direct costs of construction, interest capitalized during the period of rig construction and other direct costs necessary to bring the asset to the condition and location necessary for its intended use. When the asset is ready, it is transferred from construction in progress to the appropriate category under property and equipment. Depreciation commences upon capitalization.

Land is not depreciated.

Depreciation on other items of property and equipment is computed using the straight-line method, after allowing for salvage value of 10% where applicable, over the estimated useful lives of the assets.

The estimated useful lives of property and equipment are as follows:

	Years
Drilling rigs	30
Drilling equipment and Spares	9-13
Building	30
Other	3-5

The remaining estimated average useful life of existing drilling rigs in the Company's fleet at December 31, 2016 and 2015 is 10 and 11 years, respectively.

The Company evaluates property and equipment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. An impairment loss on property and equipment exists when the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount. Any actual impairment loss recognized represents the excess of the asset's carrying value over the estimated fair value. The Company estimates the fair values of property and equipment by applying a combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date.

When assets are sold, retired or otherwise disposed of, the cost and related accumulated depreciation are written off, net of any proceeds received, and any gain or loss is reflected in the consolidated statements of operations.

Capitalization of Interest — The Company capitalizes interest costs in connection with major construction programs, including the Newbuilds. Capitalized interest is recorded as part of the asset to which it relates and is subsequently depreciated over the asset's useful life.

Goodwill — Impairment testing for goodwill, if any, is performed annually in the fourth quarter, or when an event occurs or circumstances change that may indicate a reduction in the fair value of a reporting unit below its carrying value. A segment constitutes a business for which financial information is available and is regularly reviewed by management. The Company has one reportable segment that is contract drilling services. The individual drilling rigs are components of the segment.

Testing for goodwill impairment is a multi-step process. The Company first assesses for potential impairment on a qualitative basis, and if there is an indication of possible impairment, the following two steps must be completed to measure the amount of impairment loss, if any. The Company assesses qualitative factors to determine whether the existence of events or circumstances leads to the determination that it is more likely than not that the fair value of the segment is less than its carrying amount. If, as the result of the qualitative assessment, the Company determines that the next step of impairment test is required, or alternatively, elects to forgo the qualitative assessment, the Company tests goodwill for impairment by comparing the carrying amount of the segment to the estimated fair value of the segment to determine that it is more likely than not that the goodwill is impaired. The fair value is estimated using projected discounted future cash flows, publicly traded company multiples and / or acquisition multiples. If the estimated fair value of the Company's goodwill is less than the carrying value, the Company considers goodwill impaired and performs a second step to measure the amount of the impairment loss, if any.

Sale and Leaseback — Leases that transfer to the Company substantially all the risks and benefits incidental to ownership of the leased item are capitalized at the commencement of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between interest expense and reduction of the lease liability. Interest cost is disclosed as part of interest expense and financing charges in the consolidated statements of operations.

Leased capital assets are depreciated over the useful lives of the assets. However, if there is no reasonable certainty that the Company will obtain ownership by the end of the lease term, the asset is depreciated over the shorter of the estimated useful lives of the assets and the lease term.

Any loss arising on sale and leaseback transaction as a result of sale price lower than fair value is recognized immediately in the consolidated statements of operations. In situations where loss on sale of asset under sale and leaseback is compensated for by future lease payments at below market price, it is deferred and amortized in proportion to the lease payments over the period for which the asset is expected to be used.

Where the sale price is above fair value, the excess over fair value is deferred and amortized over the period for which the asset is expected to be used. In the case of profits arising on sale and leaseback transactions resulting in capital leases, the excess of sale proceeds over the carrying amount is deferred and amortized over the lease term.

When the Company determines that a sale and leaseback transaction is a financing activity, no gain or loss is recognized.

Lease classification is changed only if, at any time during the lease, the parties to the lease agreement agree to change the provisions of the lease (without renewing it) in a way that it would have been classified differently at inception had the changed terms been in effect at that time. The revised agreement is considered as a new agreement and accounted for prospectively over the remaining term of the lease.

Operating Lease — Operating leases are recognized as an operating expense in the consolidated statements of operations on a straight-line basis over the lease term.

Income Taxes — Income taxes are provided for based on relevant tax laws and rates in effect in the countries in which the Company operates and earns income or in which the Company is considered resident for income tax purposes. The current income tax expense reflects an estimate of the Company's income tax liability for the current year, including changes in prior year tax estimates as returns are filed, and any tax audit adjustments. Deferred income tax assets and liabilities, including net operating loss carry-forwards which the Company anticipates utilizing at the subsidiary level, reflect anticipated future tax effects of differences between the financial statement basis and tax basis of assets and liabilities based on enacted tax laws and rates applicable to the periods in which the differences are expected to affect taxable income. When necessary, valuation allowances are established to reduce deferred income tax assets to the amount expected to be realized. Reserves are recorded to offset tax benefits related to tax positions that have been taken that are more likely than not to ultimately be denied upon examination or audit by tax authorities. Any interest and penalties related to such reserves are included as a component of the income tax expense.

The Company is subject to the tax laws, including relevant regulations, treaties, and court rulings, of the countries and jurisdictions in which the Company operates. The provision for income taxes is based upon interpretation of the relevant tax laws in effect at the time the expense was incurred. If the relevant taxing authorities do not agree with the Company's interpretation and application of such laws, or if any such laws are changed retroactively, additional tax may be imposed which could significantly increase the Company's effective tax rate related to its worldwide earnings.

Contingencies — Assessments of contingencies are performed on an ongoing basis to evaluate the appropriateness of liabilities and disclosures for such contingencies. Liabilities are established for estimated loss contingencies when a loss is believed to be probable and the amount can be reasonably estimated. Corresponding assets are recognized for those loss contingencies that are assessed as probable of being recovered through insurance. Once established, the carrying amount of a contingent liability is adjusted upon the occurrence of a recognizable event when facts and circumstances change which alter previous assumptions with respect to the likelihood or amount of loss. Legal costs are expensed as incurred in the consolidated statements of operations.

Share-based Compensation — Share-based compensation is recognized in the consolidated statements of operations based on its fair value and the estimated number of shares or units that are ultimately expected to vest. For awards which vest based on service conditions, the value of the portion of the award that is ultimately expected to vest is recognized as an expense over a five year vesting period. For awards which vest only after an exit event or Initial Public Offering ("IPO"), compensation expense is recognized upon the occurrence of the event.

Employee Benefits — Statutory requirements of certain countries in which the Company operates mandate the payment of various benefits to employees who terminate employment and who have met certain minimum service requirements. The Company recognizes period costs associated with these benefits and accrues a liability for their ultimate payment. Actuarial assumptions based on employee census and historical data are incorporated into the calculation of these benefits costs. These end of service liabilities are not funded and are included in other current and other long-term liabilities in the consolidated balance sheets.

Certain employees are covered under a plan which is accounted for as a defined benefit plan. Elements of benefit obligations, net periodic benefit costs and funded status of the plan were calculated based on census and related data provided by the Company.

The Company makes contributions to a Trust fund and defined contribution savings plans which cover certain employees. Benefits under these plans vary and are generally tied to service years. These amounts are expensed as incurred.

Deferred Financing Costs — Financing costs are deferred and amortized over the life of the associated debt. In the event of early retirement of debt, any unamortized financing costs associated with the retired debt are immediately expensed.

Derivative Financial Instruments – The Company's derivative financial instruments consist of forex contracts which the Company may designate as cash flow hedges. In accordance with U.S. GAAP, each derivative contract is stated in the balance sheet at fair value with gains and losses reflected in the consolidated statements of operations except that, to the extent the derivative qualifies for and is designated as an accounting hedge, the gains and losses are reflected in income in the same period as offsetting gains and losses on the qualifying hedged positions. Designated hedges are expected to be highly effective, and therefore, adjustments to record the carrying value of the effective portion of the derivative financial instruments to their fair value are recorded as a component of accumulated other comprehensive income / (loss) ("AOCIL"), in the consolidated balance sheets. The effective portion of the cash flow hedge will remain in AOCIL until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or it is determined that the hedged transaction will not occur. The Company reports such realized gains and losses as a component of operating and maintenance expenses in the consolidated statements of operations to offset the impact of foreign currency fluctuations of the expenditures in local currencies in the countries in which the Company operates. Derivatives with asset fair values and derivatives with liability fair values are reported in other current assets or other assets and other current liabilities or other long-term liabilities, respectively, on the consolidated balance sheets depending on their maturity date.

Comprehensive Income / (Loss) - Comprehensive income / (loss) is the change in equity of a business enterprise during a period due to transactions and other events and circumstances except transactions resulting from investments by and distributions to owners. Comprehensive income / (loss) includes net income / (loss) and unrealized holding gains and losses on financial derivatives designated as cash flow accounting hedges.

Subsequent Events — Subsequent events are evaluated through the date of issuance of the financial statements.

Note 3 — New Accounting Pronouncements

Recently adopted accounting standards

In January 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-01, Income Statement – Extraordinary and Unusual Items. This ASU simplifies income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. The guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and early adoption is permitted. The Company has adopted this ASU from its effective date with no impact on the consolidated financial statements. However, if the Company has extraordinary or unusual items in the future, the adoption could have a material impact on the consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03 ("ASU 2015-03"): Interest – Imputation of Interest; Simplifying the Presentation of Debt Issuance Costs, effective for annual and interim periods beginning after December 15, 2015 for public entities. This ASU 2015-03 requires that all costs incurred to issue debt be presented in the balance sheet as a direct deduction from the carrying value of the debt. It is applied retrospectively for all prior periods presented in the financial statements prepared after the adoption. In August 2015, the FASB issued ASU 2015-15 to specifically address the presentation and subsequent measurement of debt issuance costs related to line-of-credit arrangements. ASU 2015-15 allows entities to defer and present debt issuance costs related to line-of-credit arrangements as an asset and amortize the costs ratably over the term of the line-of-credit arrangement. The Company has adopted ASU 2015-03 and ASU 2015-15 from their effective dates and has applied the new guidance to debt issuance costs. As a result of this adoption, the Company has reclassified debt issuance cost of $3.7 million and $7.1 million from other current assets and other assets, respectively, to long-term debt on the consolidated balance sheets as of December 31, 2015. See Note 10 - Debt.

Recently issued accounting standards

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. The amendments require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. As a result, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendments do not provide a definition of restricted cash or restricted cash equivalents. The amendments should be applied using a retrospective transition method to each period presented. This update is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019, with early adoption permitted. The Company does not intend to early adopt this standard. Management believes that the adoption will not have material effect on the consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15 Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments. The amendments provide guidance on eight specific cash flow issues thereby addressing the diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The eight specific cash flow issues include: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (COLIs) (including bank-owned life insurance policies (BOLIs)); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments should be applied retrospectively effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019, with early adoption permitted. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. The Company does not intend to early adopt this standard and is currently evaluating the impact of this standard on the consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. The main objective of this ASU is to improve financial reporting by requiring timelier recording of credit losses on loans and other financial instruments and to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments with enhanced disclosures that are held by a reporting entity at each reporting date. The guidance is effective for annual reporting periods beginning after December 15, 2019, with early adoption permitted. The Company does not intend to early adopt this standard and is currently evaluating the impact of this standard on the consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). Under the new guidance, lessees will be required to recognize the following for all leases (with the exception of short-term leases) at the commencement date:

- A lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and
- A right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term.

Under the new guidance, lessor accounting is largely unchanged. Certain targeted improvements were made to align, where necessary, lessor accounting with the lessee accounting model and Topic 606, Revenue from Contracts with Customers.

This ASU is effective for fiscal years beginning after December 15, 2018 and December 15, 2019 for public and private entities, respectively. The Company does not intend to early adopt this standard and is evaluating the impact of this standard on the consolidated financial statements.

In May 2014, FASB issued ASU 2014-09, Revenues from Contracts with Customers, a new guidance intended to change the criteria for recognition of revenue. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In August 2015, an additional guidance ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date was issued to delay the effective date by one year. ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) is now effective for annual and interim periods for fiscal years beginning after December 15, 2018, though companies have an option of adopting the standard for fiscal years beginning after December 15, 2017.

In March 2016 and April 2016, the FASB issued ASU No. 2016-08 Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net) and ASU No. 2016-10 Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, respectively. The amendments in ASU No. 2016-08 and ASU No. 2016-10 do not change the core principle of ASU No. 2014- 09, but instead clarify the implementation guidance on principal versus agent considerations and identify performance obligations and the licensing implementation guidance, respectively. In addition, in May 2016 and December 2016, FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients and ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers, respectively which are intended to provide clarifying guidance in certain narrow areas and add some practical expedients.

The Company does not intend to early adopt this standard. The Company is evaluating the impact of this standard on the consolidated financial statements.

Note 4 — Operating Revenues

The Company earned operating revenues from i) rigs operated by the Company and ii) rigs operated by the Seller under the Operating Agreements. See Note 1 – Nature of Business and Note 2 – Significant Accounting Policies. As of January 1, 2015, all rigs formerly operated by the Seller under the Operating Agreements are being operated by the Company. In addition, the Company earned revenue from one of its rigs under an operating lease which is reported under other operating revenue.

Operating revenues were as follows (in thousands):

	Years ended December 31,		
	2016	**2015**	**2014**
Operating revenues			
Revenue from rigs operated by the Company	$ 668,649	$ 1,012,757	$ 1,173,441
Net revenue from rigs under Operating Agreements	-	-	40,259
	$ 668,649	$ 1,012,757	$ 1,213,700

Net revenue from rigs under Operating Agreements is comprised of (in thousands):

	Years ended December 31,		
	2016	**2015**	**2014**
Gross revenue from rigs under Operating Agreements	$ -	$ -	$ 115,485
Costs and expenses			
Operating and maintenance	-	-	(64,946)
General and administrative	-	-	(1,986)
Income tax expense	-	-	(8,307)
Other income	-	-	13
Net revenue from rigs under Operating Agreements	$ -	$ -	$ 40,259

Effective January 1, 2015, the Company entered into an extension of a fixed dayrate contract with one of its customers which included a dayrate linked to the Brent crude oil price. The Company qualifies for an exemption on derivative accounting due to the correlation of the Brent crude oil price with the global offshore drilling unit dayrates. Therefore, the Company is not required to separate the embedded derivative from the drilling contract. The Company records revenue under this contract similarly to other drilling contracts.

During April 2016, the Company signed a contract amendment with the customer agreeing that the dayrate is no longer linked to the Brent crude oil price.

Note 5 — Variable Interest Entities

The Company is the primary beneficiary of four variable interest entities which are included in these consolidated financial statements.

Note 6 — Goodwill

Goodwill represents the excess of consideration paid over the fair value of net assets acquired in the Acquisition by applying the acquisition method of accounting. For the year ended December 31, 2015, the Company has determined that the goodwill was fully impaired and recognized a non-cash impairment charge of $9.3 million which was included in the loss on impairment of assets in the consolidated statements of operations. As a result, the carrying value of the goodwill as of December 31, 2015 was nil. In 2014, there were no impairment indicators identified hence no impairment of goodwill was recognized.

Note 7 — Acquired Drilling Contract Intangibles

As of December 31, 2015, all of the drilling contract intangibles acquired at the time of Acquisition, which were recorded at fair market values, had been fully amortized. The gross carrying amounts of the acquired drilling contracts and accumulated amortization were as follows (in thousands):

	Year ended December 31, 2015		
	Gross carrying amount	Accumulated amortization	Net carrying amount
Acquired drilling contracts - assets			
Beginning Balance	$ 36,258	$ (31,936)	$ 4,322
Amortization	-	(4,322)	(4,322)
Ending Balance	$ 36,258	$ (36,258)	$ -

	Year ended December 31, 2015		
	Gross carrying amount	Accumulated amortization	Net carrying amount
Acquired drilling contracts - liabilities			
Beginning Balance	$ 123,624	$ (118,319)	$ 5,305
Amortization	-	(5,305)	(5,305)
Ending Balance	$ 123,624	$ (123,624)	$ -

Note 8 — Property and Equipment

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

	December 31,	
	2016	**2015**
Drilling rigs and equipment	$ 1,138,016	$ 955,640
Construction in progress	136,834	179,261
Spares	33,866	23,947
Land and building	1,228	-
Other	16,417	16,206
Total property and equipment	$ 1,326,361	$ 1,175,054
Less: Accumulated depreciation	(295,685)	(230,421)
Total property and equipment, net	$ 1,030,676	$ 944,633

The Company added one new build rig to its drilling fleet during 2016 while there were no rig additions in 2015. As a result of this addition, the Company transferred $228.6 million from construction in progress to drilling rigs and equipment. Total capital expenditures for the years ended 2016 and 2015 were $202.8 million and $171.9 million, respectively. This includes $190.0 million and $95.3 million related to progress payments, internal project costs, change orders, owner furnished equipment and capitalized interest for the Newbuilds during 2016 and 2015, respectively. This also includes land and building acquired in 2016 for a total cost of $1.2 million, of which $564 thousand was allocated to the cost of the land which is not depreciated. The purchases of inventory are expensed as the impact on the consolidated statements of operations is broadly commensurate with the expense that would have been recorded had inventory been separately recorded on the consolidated balance sheets.

Total capital expenditures through December 31, 2016 and 2015 on the Newbuilds were $361.5 million and $171.5 million, respectively, of which $239.1 million and $74.1 million, respectively, were paid by the Lessor (see Note 11 – Sale and Leaseback).

Interest capitalized on the Newbuild rigs totaled $16.9 million and $9.4 million for the years ended December 31, 2016 and 2015, respectively. Interest capitalized during 2016 and 2015 includes $9.9 million and $1.8 million, respectively, related to the sale and leaseback financing agreements.

The Company sold two stacked rigs, Adriatic V and Adriatic VI, for $750 thousand during 2016. The carrying value of both rigs was $1.6 million and disposal costs were $260 thousand, which resulted in a loss on disposal of $1.1 million. No rig was sold by the Company during 2015. Disposals of other property and equipment were $7.5 million and $15.5 million at cost and $4.7 million and $12.0 million at net book value which resulted in a loss on disposal of assets of $3.7 million and $11.3 million during 2016 and 2015, respectively.

On March 22, 2015, a fire broke out on one of the Company's jackup drilling rigs. There was neither human casualty nor environmental damage. The rig was covered under the Company's Hull and Machinery and Excess Liability coverage for an insured value of $45 million. On August 26, 2015, the Company insurance underwriters declared the rig a Constructive Total Loss at a value of $45 million. As a result, the Company recognized an overall net gain of $25.4 million during the year ended December 31, 2015. The Company wrote-off $10.6 million net book value and $1.2 million of unamortized deferred costs, and recorded $6.8 million direct and $977 thousand other indirect costs, partly offset with the insurance proceeds received as of December 31, 2015.

Drilling rigs under capital and operating leases

The net carrying amount of property and equipment includes the newbuild rig held under a capital lease and one rig held under a bareboat charter contract accounted as an operating lease. The rig under operating lease commenced its three year bareboat charter contract (with two 12 month extension options) with a private limited liability company on February 8, 2016. These rigs are included under drilling rigs and equipment as of December 31, 2016 (2015: nil).

As of December 31, 2016, the drilling rig under capital lease had a total cost of $228.6 million and accumulated depreciation of $1.1 million and the rig under bareboat charter contract had a carrying value of $16.4 million and accumulated depreciation of $7.0 million. There were no such transactions for the year ended December 31, 2015.

As of December 31, 2016, following is the summary of future minimum rentals on operating lease (in thousands):

For the twelve months ending December 31,		
2017	$	7,759
2018		8,395
2019		713
Thereafter		-
Total future minimum rentals	$	16,867

Loss on Impairment of Assets - The Company assesses the recoverability of the Company's long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. During the fourth quarter ended December 31, 2016, the Company identified indicators of impairment impacting the Company, including the reduction in the number of new contract opportunities, lower dayrates and utilization rates due to significantly lower crude oil prices, a decrease in global demand and increase in global supply of jackup drilling rigs. As a result of these indicators, the Company concluded that a triggering event existed and an impairment assessment on the fleet of drilling rigs was required.

An impairment loss on property and equipment exists when the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition is less than its carrying amount. Any actual impairment loss recognized represents the excess of the asset's carrying value over the estimated fair value.

The fair value of the drilling rigs using the income approach is based on estimated discounted cash flows expected to result from the use of the rigs. The estimate of fair value required the Company to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the rigs, such as projected demand, rig utilization rates and dayrates. Such estimates of future undiscounted cash flows are highly subjective and are based on numerous assumptions about future operations and market conditions. The Company determined the fair value of the fleet by using the income approach and utilizing a weighted average cost of capital of 11.6% for all the rigs including the Newbuilds.

As a result of the analysis and impairment testing, the Company recognized an impairment loss of $47.1 million on three of the Company's rigs, out of which one rig was impaired to salvage value and $262.2 million on 13 of the Company's rigs, out of which five rigs were impaired to salvage values, which were included in loss on impairment of assets in the consolidated statements of operations for the years ended December 31, 2016 and 2015, respectively. The impairment loss includes the write-off of current deferred costs of $4.1 million and $11.1 million and non-current deferred costs of $4.4 million and $25.6 million for the years ended December 31, 2016 and 2015, respectively. There was no impairment recorded for the year ended December 31, 2014.

Note 9 — Income Taxes

Tax Rate — SDHL is exempt from all income taxation in the Cayman Islands.

The provision for income taxes is based on the tax laws and rates applicable in the jurisdictions in which the Company operates and earns income or is considered resident for income tax purposes. The relationship between the provision for or benefit from income taxes and the income or loss before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues rather than income before taxes, (c) rig movements between taxing jurisdictions and (d) rig operating structures.

The annual effective tax rate for the Company's continuing operations was 64.5%, (27.7)% and 13.1% for 2016, 2015 and 2014, respectively. The effective tax rate for the 2014 period does not include taxes attributed to the rigs operated by the Seller as such taxes were the legal liability of the Seller. As of January 1, 2015, the Seller no longer operates any rig owned by the Company.

Income Tax Expense — Income tax expense was $19.8 million, $30.4 million and $43.0 million for 2016, 2015 and 2014, respectively. The components of the provisions for income taxes were as follows (in thousands):

	Years ended December 31,					
	2016		2015		2014	
Current tax expense	$	19,461	$	29,081	$	46,756
Deferred tax expense / (benefit)		296		1,292		(3,724)
Income tax expense	$	19,757	$	30,373	$	43,032

The following is a reconciliation of the differences between the income tax expense for the Company's operations computed at the Cayman statutory rate of zero percent and the Company's reported provision for income taxes (in thousands):

	Years ended December 31,		
	2016	2015	2014
Income tax expense at the Cayman statutory rate	$ -	$ -	$ -
Taxes on earnings subject to rates different than Cayman statutory rate	17,604	33,051	42,046
Change in reserve for uncertain tax positions, including interest and penalties	1,098	(2,962)	-
Other	1,055	284	986
Income tax expense	$ 19,757	$ 30,373	$ 43,032

Deferred Taxes — The significant components of the Company's deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2016	2015
Deferred tax assets		
Net operating loss carry-forwards of subsidiaries	$ 4,112	$ 3,697
Valuation allowance	(975)	-
	$ 3,137	$ 3,697

	December 31,	
	2016	2015
Deferred tax liabilities		
Unremitted earnings	$ 8,525	$ 8,788

At December 31, 2016 and 2015, the Company's deferred tax liabilities include liabilities related to the future income tax cost of repatriating the unremitted earnings of certain subsidiaries that are not indefinitely reinvested or that will not be indefinitely reinvested in the future. If unforeseen law changes or other facts and circumstances cause a change in expectations regarding the future tax cost of repatriating these earnings, the resulting adjustments to the deferred tax balances could have a material effect on the Company's consolidated financial statements. The Company's deferred tax assets include subsidiary level net operating loss carry-forwards which are expected to be utilized in future periods. To the extent that insufficient taxable income is generated by the relevant subsidiaries in future years to fully utilize these net operating loss carry-forwards, any remaining carry-forwards will expire by 2024.

Liabilities for Uncertain Tax Positions — The Company has tax liabilities related to various tax positions that have been taken on the tax returns of certain subsidiaries that have resulted in a reduction in tax liabilities for those subsidiaries. In management's judgment, these tax positions are "uncertain" in that they are likely to be successfully challenged by the relevant tax authorities in the future. As such, the tax benefits related to these uncertain tax positions have been offset by a corresponding tax liability. The Company acquired a portion of these liabilities from the Seller as part of the Acquisition and is fully indemnified by the Seller for all such acquired liabilities, including any related interest and penalties. Any interest and penalties related to such liabilities are included as a component of income tax expense. Not considering any indemnification, the liabilities related to uncertain tax positions, including related interest and penalties, were as follows (in thousands):

	December 31,	
	2016	2015
Liabilities for uncertain tax positions, excluding interest and penalties	$ 2,455	$ 1,357
Interest and penalties	-	-
Liabilities for uncertain tax positions, including interest and penalties	$ 2,455	$ 1,357

The changes to liabilities for uncertain tax positions, excluding interest and penalties, were as follows (in thousands):

	December 31, 2016	December 31, 2015
Balance, beginning of year	$ 1,357	$ 3,734
(Reductions) / additions for prior period tax positions	(458)	333
Reductions related to statute of limitation expirations	(100)	(2,710)
Additions for current period tax positions	1,656	-
Balance, end of year	$ 2,455	$ 1,357

The Company engages in ongoing discussions with tax authorities regarding the resolution of tax matters in the various jurisdictions in which it operates. Both the ultimate outcome of these tax matters and the timing of any resolution or closure of the tax audits are uncertain. While the Company cannot predict or provide assurance as to the final outcome of these proceedings, it does not expect the ultimate liability to have a material adverse effect on its consolidated financial statements. Further, the Company is indemnified from any tax liabilities of subsidiaries previously owned by the Seller related to the periods prior to the Acquisition.

Tax Returns — The Company is currently subject to or expects to be subject to income tax examinations in various jurisdictions where the Company operates or has previously operated. While the Company cannot predict or provide assurance as to the final outcome of any tax proceedings, the Company does not expect the ultimate tax liability to have a material adverse effect on its consolidated balance sheets or consolidated statements of operations. Any tax liability relating to entities acquired by the Company from the Seller and relating to periods prior to the Acquisition are indemnified by the Seller.

Other Tax Matters — Operations are conducted through various subsidiaries in a number of countries throughout the world. Each country has its own tax regimes with varying nominal rates, deductions and tax attributes. From time to time, changes to previously evaluated tax positions may be identified that could result in adjustments to the current recorded assets and liabilities. Although it is not possible to predict the outcome of these changes, it is not expected that the effect, if any, resulting from these assessments to have a material adverse effect on the consolidated balance sheets, statements of operations or statements of cash flows.

Note 10 — Debt

Debt is comprised of the following (in thousands):

	December 31, 2016	December 31, 2015
8.625% Senior Secured Notes, due November 1, 2018 (see note (i) below)	$ 466,857	$ 464,204
Revolving Credit Facility, due April 30, 2018 (see note (ii) below)	-	-
Total debt	$ 466,857	$ 464,204

The following is a summary of scheduled long-term debt maturities by year (in thousands):

For the twelve months ending December 31,	
2017	$ -
2018	466,857
Total debt	$ 466,857

The following tables provide details of principal amount and carrying values of debt (in thousands):

	December 31, 2016		
	Principal Amount	Unamortized Debt Issuance Costs	Carrying Value
8.625% Senior Secured Notes, due November 1, 2018	$ 475,000	$ 8,143	$ 466,857

	December 31, 2015		
	Principal Amount	Unamortized Debt Issuance Costs	Carrying Value
8.625% Senior Secured Notes, due November 1, 2018	$ 475,000	$ 10,796	$ 464,204

The following tables summarized the total interest on debt (in thousands):

	Year ended December 31, 2016		
	Coupon Interest	Amortization of Debt Issuance Costs	Total Interest
8.625% Senior Secured Notes, due November 1, 2018	$ 40,969	$ 2,653	$ 43,622

	Year ended December 31, 2015		
	Coupon Interest	Amortization of Debt Issuance Costs	Total Interest
8.625% Senior Secured Notes, due November 1, 2018	$ 40,969	$ 3,528	$ 44,497

The outstanding debt balances as of December 31, 2016 and 2015 reflect the adoption of ASU 2015-03 as discussed in Note 3 – New Accounting Pronouncements. The effective interest rate on the 8.625% Senior Secured Notes is 9.79%.

(i) 8.625% Senior Secured Notes, due November 2018

On October 24, 2012, SDHL completed the issuance and sale of $475 million aggregate principal amount of the 8.625% senior secured notes due November 1, 2018. The 8.625% Senior Secured Notes were sold at par and SDHL received net proceeds from the offering of the 8.625% Senior Secured Notes of $452.8 million after deducting the offering expenses of $22.2 million. Interest on the 8.625% Senior Secured Notes accrues from October 25, 2012 at a rate of 8.625% per year and is payable semi-annually in arrears on May 1 and November 1 of each year, beginning May 1, 2013.

SDHL's obligations under the 8.625% Senior Secured Notes are guaranteed by a majority of SDHL's subsidiaries (collectively, the "Note Guarantors"), subject to certain exceptions. The obligations of the Note Guarantors are secured by liens on the rigs and other assets owned by the Note Guarantors. These liens are subordinate to the liens securing the obligations of the Note Guarantors under the Revolving Credit Facility ("SDHL Revolver").

SDHL may redeem the 8.625% Senior Secured Notes, in whole or part, at the redemption prices set forth below, together with accrued and unpaid interest to the redemption date.

Period	Redemption Price
On or after May 1, 2015	104.313%
On or after November 1, 2016	102.156%
On or after November 1, 2017 and thereafter	100.000%

If SDHL experiences a change of control, as defined in the indenture governing the 8.625% Senior Secured Notes (the "Indenture"), it must offer to repurchase the 8.625% Senior Secured Notes at an offer price in cash equal to 101% of their principal amount, plus accrued and unpaid interest. Furthermore, following certain asset sales, SDHL may be required to use the proceeds to offer to repurchase the 8.625% Senior Secured Notes at an offer price in cash equal to 100% of their principal amount, plus accrued and unpaid interest.

On January 12, 2017, the Company exchanged and cancelled $444.585 million of 8.625% Senior Secured Notes at 100% redemption price. See Note 24 – Subsequent Events.

(ii) Revolving Credit Facility, due April 2018

On February 24, 2014, SDHL entered into a $150 million Revolving Credit Facility which was available for utilization on February 28, 2014. The SDHL Revolver can be drawn as cash, letters of credit or bank guarantees, or a mixture of cash, letters of credit and guarantees, subject to the satisfaction of customary conditions set forth in the underlying credit agreement. All borrowings under the SDHL Revolver mature on April 30, 2018, and letters of credit and bank guarantees issued under the SDHL Revolver expire no later than five business days prior to April 30, 2018. On June 11, 2014 in accordance with the terms of the SDHL Revolver, the Company sought and was granted, an increase in the total amount available under the SDHL Revolver to $200 million.

The Company issued bank guarantees and performance bonds totalling $28.5 million and $48.3 million as of December 31, 2016 and 2015, respectively, against the SDHL Revolver. As a result, the remaining available balance under the Revolving Credit Facility is $171.5 million and $151.7 million as of December 31, 2016 and 2015, respectively. The second lien note indenture currently restricts the SDHL Revolver capacity to $170 million, as such the available amount for drawdown under the SDHL Revolver as of December 31, 2016 was $141.5 million.

Cash borrowings under the SDHL Revolver bear interest, at SDHL's option, at either (i) the Adjusted Libor Rate plus Applicable Margin, as defined in the SDHL Revolver or (ii) the Alternate Base Rate ("ABR", the highest of the prime rate, the federal funds rate plus 0.5% per year, or the one-month Adjusted LIBOR Rate (as defined in the SDHL Revolver) plus 1% per year), plus Applicable Margin. During the years ended December 31, 2016 and 2015, the amortization of debt issuance costs on the SDHL Revolver amounted to $1.7 million and $1.8 million, respectively.

Participation fees accrue on financial letters of credit and bank guarantees at the Applicable Margin for borrowings at the Adjusted LIBOR Rate and on non-financial letters of credit and bank guarantees at 50% of the Applicable Margin for borrowings at the Adjusted LIBOR Rate. The Applicable Margin is calculated based on credit ratings of SDL by Standard and Poor's and Moody's; currently the Applicable Margin is 4.75% per year for borrowings at the Adjusted LIBOR Rate.

The Applicable Margin can range from a maximum of 5.0% per year and a minimum of 3.5% per year for borrowings at the Adjusted LIBOR Rate and from a maximum of 4.0% per annum and a minimum of 2.5% per year for borrowings at the Alternate Base Rate. SDHL is liable to pay a commitment fee to the administrative agent on the daily unused amount of the SDHL Revolver at 30% of the Applicable Margin for borrowings at the Adjusted LIBOR Rate. The facility is cancellable by SDHL at any time with no penalty or premium.

Additionally, if SDHL as of the last day of any fiscal quarter is using more than 25% of the SDHL Revolver (excluding non-financial or cash-collateralized letters of credit and bank guarantees), then the SDHL Revolver requires that SDHL and the Guarantors (as defined below) have a total net leverage ratio (consolidated net indebtedness to consolidated EBITDA, as defined in the SDHL Revolver) of not greater than 3:1 for the four consecutive fiscal quarters ended on such last day. This covenant did not apply as the Company had not met the more than 25% threshold during the years ended December 31, 2016 and 2015.

SDHL's obligations under the SDHL Revolver are guaranteed by the majority of SDHL's subsidiaries (collectively, the "Guarantors"), subject to certain exceptions. The obligations of the Guarantors are secured by liens on the rigs and other assets owned by the Guarantors. The liens securing the SDHL Revolver are senior to the liens securing the 8.625% Senior Secured Notes.

On January 12, 2017, the Company successfully amended its revolving credit agreement. See Note 24 – Subsequent Events.

Terms Common to All Indebtedness

The Indenture and the SDHL Revolver contain customary events of default. These agreements also contain a provision under which an event of default by SDHL or by any restricted subsidiary (under the SDHL Revolver and the Indenture) on any other indebtedness exceeding $25 million would be considered an event of default if such default: a) is caused by failure to pay the principal or interest when due after the applicable grace period, or b) results in the acceleration of such indebtedness prior to maturity.

The Indenture and the SDHL Revolver contain covenants that, among other things, limit SDHL's and SDIL's ability and the ability of their restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- make restricted payments or investments;
- sell assets;
- create liens;
- engage in transactions with affiliates; and
- consolidate, merge or transfer all or substantially all of its assets.

The Company incurred a total of $7.2 million of transaction costs related to the SDHL Revolver and $22.2 million of transaction costs related to issuance of 8.625% Senior Secured Notes. These costs are amortized over the life of the associated debt and the unamortized portion is netted off against the debt's carrying value, except for the $7.2 million transaction costs for the SDHL Revolver which are carried as both short-term and long-term term assets on the consolidated balance sheets and are being amortized over the life of the associated debt.

Note 11 — Sale and Leaseback

On October 10, 2015, two wholly owned subsidiaries of SDHL, Shelf Drilling TBN I, Ltd and Shelf Drilling TBN II, Ltd (collectively, the "Lessee"), whose assets consist solely of the two under construction fit-for-purpose new build jackup rigs entered into a combined minimum of $296.2 million and maximum of $330.0 million ("Purchase Price") sale and leaseback financing transactions (the "Sale and Leaseback Transactions") with Hai Jiao 1502 Limited and Hai Jiao 1503 Limited (collectively, the "Lessor"), both wholly owned subsidiaries of Industrial and Commercial Bank of China Leasing. In connection with these transactions, the Lessee executed Memorandum of Agreements and Bareboat Charter agreements to sell the rigs and bareboat charter the rigs back from the Lessor upon expected delivery date for a period of 5 years and 90 days. See Note 8 – Property and Equipment.

The Company, in substance, is the accounting owner of the Newbuilds during the construction period due to being the primary obligor on the construction contract and its involvement during the construction period. The Company effectively receives the Purchase Price over the construction period from the Lessor in the form of construction milestone payments paid directly by the Lessor to the Builder on various due dates as per the construction contracts and the remaining balance reimbursed to the Company on the Bareboat Charter commencement dates. The Company records these payments as construction in progress and long-term liabilities on its consolidated balance sheets until the assets are completed and delivered. The Company, being the accounting owner of the Newbuilds, has also recorded $7.6 million as construction in progress payments for set-up fees, legal fees, brokerage fees and handling fees related to these sale and leaseback transactions. No profit and loss is recognized on these sale and leaseback transactions as the Company retains substantially all the benefits and risks incidental to the ownership of the property sold.

The Company is liable to pay a commitment fee of 1.20% per annum to the Lessor calculated on undrawn amount of Purchase Price calculated from October 10, 2015 until the Purchase Price is paid in full for each rig, payable on the date of first installment payment of Purchase Price and quarterly in arrears thereafter. The milestone payments bear interest at 3 months LIBOR plus an applicable margin of 4% annually. Such interest is capitalized at intervals of three months from the date of payment of each installment until the lease commencement date.

The Bareboat Charter agreements require scheduled monthly rent payments ("Rent") with variable and fixed payment components from the Bareboat Charter commencement dates through its estimated maturities on December 28, 2021 and June 30, 2022 at which time the Lessee will have the obligation to acquire the Newbuilds from the Lessor for $82.5 million each ("Purchase Obligation Price"). The fixed monthly average payments for each rig at the inception of the bareboat charter period are calculated using the Prepaid Purchase Price (Purchase Price and capitalized interest on milestone payments net of Purchase Obligation) over the lease term. The average variable payments over the lease term for each rig are calculated on each payment date using a projected 3 months LIBOR rate plus applicable margin of 4% annually on the Notional Rent Outstanding (Prepaid Purchase Price reduced by fixed payments). The charter payments will be made in advance every 5th day of the month.

On December 1, 2016, after completion of the final customer acceptance requirements, the rig commenced a five-year contract with Chevron. The Company accounted for this sale and leaseback transaction as a capital lease and transferred $228.6 million from construction in progress to drilling rigs and equipment in property and equipment. See Note 8 – Property and Equipment. The capital lease contract has an estimated average interest rate of 5.823% and requires scheduled monthly average principal payments of $1.4 million and average interest payments of $607 thousand through December 5, 2021.

As of December 31, 2016, the following is a summary of the estimated future rental payments on capital lease (in thousands):

For the twelve months ending December 31,		
2017	$	23,698
2018		25,680
2019		25,102
2020		24,318
2021		105,293
Thereafter		-
Total future rental payments	$	204,091

The Company made rental payments, including interest, of $2.7 million during the year ended December 31, 2016. This includes pre-payments of principal and interest of $1.5 million and $729 thousand, respectively.

The outstanding balance of obligations under sale and leaseback is $244.7 million and $74.7 million as of December 31, 2016 and 2015, respectively. The current year balance consists of $16.0 million which represents the scheduled monthly principal installments for the newbuild rig which started its drilling contract on December 1, 2016 and $228.7 million as long term obligations. The long term obligations comprise of $152.0 million for the newbuild rig under capital lease and $76.7 million for the newbuild rig still under construction. The prior year balance of $74.7 million represents the long term obligations for the newbuilds under construction.

The Lessor paid $165.0 million ($148.1 million was paid directly to the Builder and $16.9 million to the Company for costs incurred) and $74.1 million ($55.5 million was paid directly to the Builder and $18.5 million to the Company related to milestone payment) during the years ended December 31, 2016 and 2015, respectively. In addition, the Company recorded $6.8 million and $643 thousand for interest in kind on the obligations under the sale and leaseback during the years ended December 31, 2016 and 2015.

The Company has the right to purchase either of the rigs on an “as is where is” basis, after the delivery date and without any default during the bareboat charter agreement period, at redemption prices as follows:

Period	Redemption Price
Year 1	Notional Rent Outstanding * (1+3%)
Year 2	Notional Rent Outstanding * (1+2%)
Year 3	Notional Rent Outstanding * (1+2%)
Year 4	Notional Rent Outstanding * (1+1%)
Year 5	Notional Rent Outstanding * (1+1%)

Besides the redemption price, the Company is required to pay any rent and other amounts due, and the broken funding costs as defined in the Bareboat Charter agreements.

The Lessor also has the right to compel the Company to purchase the relevant rig when there is a termination event at a price of an aggregate of the Notional Rent Outstanding plus a 3% fee on the Notional Rent Outstanding. The Company is also required to pay any rent and other amounts due, and the broken funding costs as defined in the Bareboat Charter agreements. This option is not exercisable by the Lessor when the relevant rig is in service under its contract with Chevron.

The Company’s obligation under the sale and leaseback transactions is secured by pledge over all bank accounts specific to this transaction and pledge of shares of certain wholly owned subsidiaries of the Company. The Company has also assigned to Lessor the construction contracts with the Builder, the advance payment guarantee covering 30% of the contract price received from the Builder which is valid during the construction period, an additional payment guarantee covering 10% of the contract price which is also valid during the construction period, and the receivable and earnings from the Chevron contracts.

The Company is also required to maintain (1) a minimum of 90 days of Rent in a Debt Reserve Account; and (2) 120% of Security Coverage Ratio (Fair Value of the rig and associated drilling service contract to the Notional Rent Outstanding). In addition, SDL is also required to maintain a Consolidated Net Debt to Consolidated EBITDA Ratio not to exceed 4:1, as defined in the Bareboat Charter agreement. As of December 31, 2016 and 2015, the Company and SDL were in compliance with all the above mentioned requirements as applicable.

The lease agreements contain certain representations, warranties, obligations, conditions, indemnification provisions and termination provisions customary for sale and leaseback financing transactions. The lease agreements contain certain affirmative and negative covenants that, subject to exceptions, limit the Lessee's ability to, among other things, incur additional indebtedness and guarantee indebtedness, pay dividends or make other distributions or repurchase or redeem capital stock, make loans and investments, sell, transfer or otherwise dispose of certain assets, create or incur liens and enter into certain types of transactions with affiliates, consolidate, merge or sell all or substantially all of its assets.

Note 12 — Employee Benefit Plans

The Company makes regular monthly cash contributions to defined contribution retirement and savings plans. The Company also makes cash payments whenever the departure of an employee triggers the requirement to pay an end of service payment under local labor laws or the Company policy.

Retirement and Savings Plans — The Company contributes between 4.5% and 6.5% of certain employees' base salaries each month into an employee's retirement plan. The actual percentage rate contribution is determined by the number of years of service with the Company, including, for certain employees, the number of years of service with the Seller. The Company has no further obligations for these retirement plans and the Company's contributions are expensed as incurred.

Certain employees have the option to contribute a percentage of their base salary to an individual savings plan. The Company will match up to 6% of the employee's base salary and pay it into the savings plan. The Company has no further obligations for this savings plan and the Company's contribution is expensed as incurred.

The Company has recorded approximately $5.3 million, $7.3 million and $7.5 million in expense related to defined contribution retirement and savings plans for 2016, 2015 and 2014, respectively.

Retirement plan under a Trust fund – On August 1, 2016, the Company replaced the end of service benefit covering certain employees previously reported under a defined benefit plan with a defined retirement contribution plan managed under a trust fund. The remeasured end of service liability under the new plan was $1.3 million, which resulted in a gain of $248 thousand during the year ended December 31, 2016.

Contributions are made on a monthly basis by the Company irrespective of fund performance and are not pooled, but are separately identifiable and attributable to each employee. The Company has no further obligation for this retirement plan and the Company's contributions are expensed as incurred.

Contribution expense related to this plan is $122 thousand from the effective date of August 1, 2016 to December 31, 2016. The expenses were previously recorded as end of service benefit expense during the years ended 2014, 2015 and through to July 31, 2016.

End of Service Plans — The Company offers end of service plans to employees in certain countries in accordance with the labor laws in these countries or the Company policy.

The Company has recorded approximately $6.3 million, $6.7 million and $1.2 million in expense related to employee end of service plans for 2016, 2015 and 2014, respectively. The 2014 expense amount includes a gain resulting from a change in the accounting estimate related to the Company's initial actuarial valuation performed in 2014 of the benefits due which indicated a reduction in the previously estimated liability by approximately $6.5 million. Additionally, the Seller paid the Company $4.4 million in 2014 to settle a portion of its future liabilities under these plans.

Countries in which management estimates that the liabilities are significant in amount are subject to an analysis which considers specific actuarial assumptions for those countries. The discount rate used in the analyses ranged from 4.2% to 16.5% and the assumed average annual rate of compensation increase ranged from 2% to 5%.

The estimated total liability for the end of service plans was $8.8 million and $15.1 million at December 31, 2016 and 2015, respectively.

Defined Benefit Plan — As a result of the Acquisition described in Note 1 — Nature of Business, the Company agreed to replicate certain employee benefits for the employees of the Seller who joined the Company. Benefits under this plan vest immediately and are paid in a single lump sum cash payment when a participant has both reached the age of 55 and is no longer employed by the Company. The single sum paid is calculated taking into account employee's base salary and various other factors. The Company has removed the restriction of the minimum age of 55 related to this plan as of January 1, 2016.

The number of employees who were eligible for benefits under this plan totaled 63, 99 and 120 at December 31, 2016, 2015 and 2014, respectively. The plan freeze date is December 31, 2015 and the Company stopped accruing service awards benefits as of January 1, 2016. The plan is currently unfunded.

A reconciliation of the changes in benefit obligation is as follows (in thousands):

	Years ended December 31,	
	2016	2015
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 4,913	$ 3,346
Service cost	-	2,960
Interest cost	146	79
Plan changes	-	-
Benefits paid	(1,737)	(1,078)
Actuarial gain	(156)	(394)
Curtailment	-	-
Benefit obligation, end of year	$ 3,166	$ 4,913

The Company has recorded $481 thousand and $739 thousand as current, and $2.7 million and $4.2 million as non-current obligations for this plan as of December 31, 2016 and 2015, respectively.

The benefit cost includes the following components (in thousands):

	Years ended December 31,		
	2016	2015	2014
Net periodic benefit (gain) / costs			
Service cost	$ -	$ 2,960	$ 2,795
Interest cost	146	79	23
Expected return on plan assets	-	-	-
Amortization of prior service cost	-	-	-
Actuarial gain	(156)	(394)	(315)
Net periodic benefit (gain) / costs, end of year	$ (10)	$ 2,645	$ 2,503

The plan does not have any assets, nor does the Company intend to fund the plan. The Company has elected to immediately recognize any gains and losses from this plan and as such no amounts have been recorded in accumulated other comprehensive income related to the plan.

The key assumptions for the plan are summarized below:

	Years ended December 31,	
	2016	2015
Weighted-average assumptions used to determine benefit obligations:		
Discount rate	3.00%	3.21%
Rate of compensation increase	N/A	N/A

	Years ended December 31,		
	2016	2015	2014
Weighted-average assumptions used to determine net periodic benefit costs:			
Discount rate	3.00%	3.21%	2.35%
Rate of compensation increase	N/A	N/A	4.00%
Expected long-term rate of return on assets	N/A	N/A	N/A

The future estimated payouts are as follows (in thousands):

	Projected benefit payments
Years ending December 31,	
2017	$ 481
2018	471
2019	523
2020	265
2021	348
2022 - 2026	1,140

Retention Plans — The Company also sponsors medium term cash incentive programs for certain employees. The plans generally vest over a period ranging from one to two years, and associated payouts are made over a two year period provided the participant is still employed. The pay outs under existing plans are expected to occur in March, 2017 and March, 2018. The Company recorded approximately $3.0 million, $3.0 million and $5.3 million expense under the plans for the years ended December 31, 2016, 2015 and 2014, respectively. The estimated total cash payments under the retention plans for 2017 and 2018 are $2.7 million and $3.3 million, respectively.

Note 13 — Commitments and Contingencies

Operating Lease Obligations – The Company has operating lease commitments expiring at various dates, principally for office space, expatriate employee accommodation and office equipment.

Sale and Leaseback Obligations – This represents minimum annual rental payments and Purchase Obligation Price assuming average estimated interest rates pursuant to the sale and leaseback transactions as of December 31, 2016. See Note 11 - Sale and Leaseback.

As of December 31, 2016, contractual payments related to those matters were as follows (in thousands):

	Operating leases	Sale and leaseback obligations	Total commitments
For the twelve months ending December 31,			
2017	$ 6,367	$ 37,379	$ 43,746
2018	4,207	52,082	56,289
2019	474	50,946	51,420
2020	189	49,387	49,576
2021	82	129,337	129,419
Thereafter	-	93,705	93,705
Total	$ 11,319	$ 412,836	$ 424,155

Legal Proceedings — The Company is involved in various claims and lawsuits in the normal course of business, some of which existed at the time of Acquisition and are indemnified by the Seller. As of December 31, 2016 and 2015, management has determined that there are no significant claims or lawsuits to disclose including claims and lawsuits fully indemnified by the Seller and no provisions were necessary.

Insurance

The Company's hull and machinery, property, cargo and equipment and excess liability insurance consists of commercial market policies that the Company renewed on November 30, 2016 for one year. The Company periodically evaluates its risks, insurance limits and self-insured retentions. As of December 31, 2016, the insured value of the Company's drilling rig fleet was $1.6 billion, which includes the newbuild rig which commenced its drilling contract on December 1, 2016.

Hull and Machinery Coverage — At December 31, 2016, under the Company's hull and machinery insurance policies, the Company maintained a $5 million deductible per occurrence , with no deductible in the event of loss greater than 75% of the insured value of the rig. The Company also has insurance coverage for costs incurred for wreck removal for the greater of 25% of the rig's insured value or $20 million (plus an additional $25 million per occurrence) with a nil deductible. The hull and machinery policy also covers war risk, which is cancellable either immediately or with 7 days' notice by the underwriters in certain circumstances. To protect against this cancellation risk, the Company also insures, through commercial market policies, a Political Risks Policy covering acts of war and terrorism with a $250,000 deductible per occurrence (an additional $2.75 million in certain countries) and a limit of $175 million.

Excess Liability Coverage — At December 31, 2016, the Company carried $400 million of commercial market excess liability coverage, exclusive of the deductibles, which generally covered onshore and offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including pollution from the rig and non-owner aviation liability. The Company's excess liability coverage generally has a $1 million deductible per occurrence.

At December 31, 2016, the Company also carried $100 million of additional insurance per occurrence that generally covered expenses that would otherwise be assumed by the well owner, such as costs to control the well, re-drill expenses and pollution from the well. This additional insurance provides coverage for such expenses in circumstances in which the Company has a legal or contractual liability arising from gross negligence or willful misconduct. The deductible is $1 million per occurrence.

Self-Insured Medical Plan — The Company offers a self-insured medical plan ("the Medical Plan") for U.S. resident rig based expatriates employees and their eligible dependents to provide medical, vision, dental within the U.S. and security evacuation and repatriation. The maximum potential liability related to the plan excluding dental benefits is $1.7 million as of December 31, 2016, as the Company is reinsured for the excess amount by a third party insurance provider.

Surety Bonds — It is customary in the contract drilling business to have various surety bonds in place that secure customs obligations relating to the temporary importation of rigs and equipment and certain contractual performance and other obligations.

The Company has surety bond facilities in either U.S. dollars or local currencies of approximately $85.0 million provided by several banks to guarantee various contractual, performance, and customs obligations. The Company entered into these facilities in India, Egypt, UAE and Nigeria. The outstanding surety bonds were $33.3 million and $64.2 million at December 31, 2016 and 2015 (including $7.8 million surety bonds for which the credit facility was not in place which were secured by 100% cash deposits in 2015), respectively.

In addition, the Company had outstanding bank guarantees and performance bonds amounting to $28.5 million and $48.3 million as of December 31, 2016 and 2015, respectively, against the $200 million SDHL Revolver.

Therefore, the total outstanding bank guarantees and surety bonds issued by the Company were $61.8 million and $112.5 million as of December 31, 2016 and 2015, respectively.

Under the terms of the Acquisition, the Seller agreed to continue to provide financial support by maintaining letters of credit, surety bonds and other performance and obligation guarantees. This agreement with the Seller to provide financial support expired on November 30, 2015. The Seller did not issue any new letter of credits, surety bonds and other performance and obligation guarantees after November 30, 2015. All outstanding surety bonds provided by the Seller on the Company's behalf of $23.7 million as of December 31, 2015 were cleared and replaced by the Company's issued surety bonds in 2016.

Note 14 — Fair Value of Financial Instruments

The carrying amounts of the Company's financial instruments, which include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, approximate their fair market values due to the short-term nature of the instruments.

The following table represents the estimated fair value and carrying value of the Company's long-term debt (in thousands):

	December 31, 2016		December 31, 2015	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
8.625% Senior Secured Notes, due November 1, 2018	$ 466,857	$ 399,000	$ 464,204	$ 361,000

The estimated fair value of the Company's long-term debt was determined using quoted market prices. Where more than one quoted market price was obtained, the average of all the quoted market prices was applied (Level 2 measurement).

Derivative financial instrument was measured at fair value on a recurring basis using Level 2 inputs. See Note 18 – Derivative Financial Instruments. At December 31, 2016, there were no outstanding derivative contracts.

Note 15 — Financial Instruments and Risk Concentration

Interest Rate Risk — Financial instruments that potentially subject the Company to concentrations of interest rate risk include cash and cash equivalents, debt and the obligation under sale and leaseback. Exposure to interest rate risk may occur in relation to cash and cash equivalents, as the interest income earned on these balances changes with market interest rates. Floating rate debt, where the interest rate may be adjusted annually or more frequently over the life of the instrument, exposes the Company to short-term changes in market interest rates. Fixed rate debt, where the interest rate is fixed over the life of the instrument and the instrument's maturity is greater than one year, exposes the Company to changes in market interest rates if and when refinancing of maturing debt with new debt occurs.

Foreign Currency Risk — The Company's functional currency is the U.S. dollar and its international operations expose it to currency exchange rate risk. This risk is primarily associated with the compensation costs of the Company's employees and purchasing costs from non-U.S. suppliers, which are generally denominated in currencies other than the U.S. dollar.

The Company's primary currency exchange rate risk management strategy involves structuring customer contracts to provide for payment in U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. Due to various factors, including customer acceptance, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual local currency needs may vary from those anticipated in the customer contracts, resulting in partial exposure to currency exchange rate risk. The currency exchange effect resulting from the Company's international operations generally has not had a material impact on its operating results. The Company recognized $1.9 million gain, $1.7 million gain and $1.4 million loss related to net foreign currency exchange during 2016, 2015 and 2014, respectively, which are included in other, net in the consolidated statements of operations.

Further, the Company may utilize forex contracts to manage foreign exchange risk, for which the Company has documented policies and procedures to monitor and control the use of the derivative instruments. The Company does not engage in derivative transactions for speculative or trading purposes. The Company's forex contracts generally require it to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date. As of December 31, 2016, the Company had no forex contracts outstanding. There were no such transactions as of December 31, 2015.

Credit Risk — Financial instruments that potentially subject the Company to concentrations of credit risk are cash and cash equivalents and accounts receivables.

The Company generally maintains cash and cash equivalents at commercial banks with high credit ratings.

The market for the Company's services is the offshore oil and natural gas industry. The Company's customers primarily consist of government owned or controlled energy companies, publicly listed integrated oil companies or independent exploration and production companies. Periodic credit evaluations of the Company's customers are performed and generally do not require material collateral. The Company may from time to time require its customers to issue a bank guarantee in its favor to cover non-payment under drilling contracts.

Allowance for doubtful accounts are based upon expected collectability on a contract by contract basis where the required payment of specific amounts owed to the Company is unlikely to occur. At December 31, 2016 and 2015, the allowance for doubtful accounts was $99.6 million and $110.2 million, respectively.

Note 16 — Restricted Cash

The Company maintained a restricted cash deposit of $9.3 million and $8.8 million as of December 31, 2016 and 2015, respectively, which is included in other current assets and other assets in the consolidated balance sheets. Restricted cash is primarily used as collateral for bid tenders and performance bonds. The increase in restricted cash in 2016 was related to the reserve requirements for the sale and leaseback transaction amounting to $6.4 million, partly offset by the $5.9 million cash collateral released in the first quarter of the current year.

Note 17 — Share-based Compensation

SDL has a share-based compensation plan under which it issues Class B time based restricted shares and Class C performance based shares to certain members of the Company's management as remuneration for future service of employment.

The Company has recorded a share-based compensation expense of $179 thousand (net of a $487 thousand gain related to forfeitures and an additional expense of $23 thousand for repurchased vested shares), $638 thousand (net of a $34 thousand gain related to forfeitures and an additional expense of $18 thousand for repurchased vested shares) and $2.0 million (net of a $47 thousand gain related to forfeitures) in 2016, 2015 and 2014, respectively. No income tax benefit was recognized for these plans.

Time Based Restricted Class B Ordinary Shares

Time based restricted shares are awarded as Class B ordinary shares which typically vest in equal proportion over a period of five years from the grant date provided the grantee remains employed by the Company. Upon vesting these shares are non-transferable. In the event of an IPO or other exit event, all Class B shares, regardless of grant date, vest immediately. Following an IPO or other exit event, Class B shares held by members of management continue to be non-transferable pursuant to the terms of a management-shareholder agreement. These transfer restrictions lapse ratably over three years, at one year intervals beginning twelve months after an IPO or other exit event. Compensation cost is recognized over a period of five years from the grant date subject to acceleration as discussed above in the event of an IPO or other exit event.

Performance Based Class C Ordinary Shares

Performance based shares are awarded as Class C ordinary shares which have rights to dividends or distributions at certain pre-defined amounts of aggregate distributions which are junior to holders of the Class A and Class B shares. The specifics of these rights are set forth in the Articles. Upon an exit event or IPO, Class C shares vest immediately and are subject to the same transferability restrictions as described above regarding Class B shares with those restrictions being lifted ratably over a three year period beginning on the first anniversary of the IPO or exit event. At the end of the third year after the IPO or exit event, all the restrictions would have been lifted. Compensation expense related to the grant date fair value of the Class C shares will be recognized upon vesting.

The fair value of awards made under the share-based compensation plans is estimated at the grant date using standard quantitative modeling techniques performed by an independent third party. The estimates are established using a zero premium option, with reference to the volatility of a group of broadly similar offshore drilling service companies. The following assumptions were used in the valuation calculations for shares awarded in 2016. There were no shares awarded in 2015, therefore the assumptions were not applicable:

	Years ended December 31,			
	2016		2015	
	Class B	Class C	Class B	Class C
Valuation assumptions:				
Expected term	2 years	2 years	N/A	N/A
Risk free interest rate	2 Year US Treasury Bond	2 Year US Treasury Bond	N/A	N/A
Expected volatility	60.0%	60.0%	N/A	N/A
Dividend yield	Nil	Nil	N/A	N/A

Expected Term: The expected term represents the period from the grant date to the expected date of vesting, either through an IPO or other exit event.

Risk Free interest rate: The US Treasury Bond rate as of the grant date over a similar period to the Expected Term.

Expected Volatility: The average historical 36-month period volatility of the quoted share prices of a group of broadly similar publicly quoted offshore drilling service companies. The variables are adjusted to reflect the gross debt to capitalization ratio of each company.

Dividend Yield: The Company has not historically issued any dividends on these classes of shares and does not expect to in the future nor are the unvested shares entitled to dividends.

The following table summarizes the awards held by the Company's management under the Company's two share-based compensation plans:

	Time based restricted shares	Performance based shares	Weighted average grant date fair value per share	
	Class B	Class C	Class B	Class C
Non-vested shares at January 1, 2016	9,041	961	$ 261.93	$ 4,259.24
Granted	2,659	176	456.22	4,677.20
Vested	(2,503)	-	245.62	-
Forfeited	(1,493)	(172)	185.23	4,217.58
Non-vested shares at December 31, 2016	7,704	965	$ 357.05	$ 5,808.48

	Time based restricted shares	Performance based shares	Weighted average grant date fair value per share	
	Class B	Class C	Class B	Class C
Non-vested shares at January 1, 2015	12,125	973	$ 273.25	$ 4,829.14
Granted	-	-	-	-
Vested	(2,905)	-	213.50	-
Forfeited	(179)	(12)	1,814.00	51,100.00
Non-vested shares at December 31, 2015	9,041	961	$ 261.93	$ 4,259.24

Total unrecognized compensation expense related to non-vested Class B and C shares was $8.4 million and $7.6 million at December 31, 2016 and December 31, 2015, respectively.

Note 18 — Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

The Company may enter into forex contracts when management believes that market conditions are favorable to purchase contracts for future settlement with the expectation that such contracts, when settled, will reduce the exposure to foreign currency gains and losses on future foreign currency expenditures. The amount and duration of such contracts are based on the monthly forecast of expenditures in the foreign currencies in which the Company conducts significant business and for which there is a financial market. These forward contracts are derivatives and any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

During the year ended December 31, 2016, the Company settled forex contracts with aggregate notional values of approximately $21.6 million, of which the aggregate amounts were designated as an accounting hedge. There were no such transactions for the year ended December 31, 2015 and 2014, respectively. There were no forex contracts outstanding as of December 31, 2016.

The following table presents the amounts recognized in the Company's consolidated statements of operations related to the derivative financial instruments designated as cash flow hedges (in thousands). The effective portion of gain / (loss) reclassified from AOCIL is recorded under operating and maintenance.

	Gain recognized through AOCIL		
	Years ended December 31,		
	2016	2015	2014
Cash flow hedges			
Foreign currency forward contracts	$ 427	$ -	$ -

	Gain reclassified from AOCIL to "Operating and maintenance"		
	Years ended December 31,		
	2016	2015	2016
Cash flow hedges			
Foreign currency forward contracts	$ 427	$ -	$ -

Note 19 — Supplemental Balance Sheet Information

Accounts and other receivables consisted of the following (in thousands):

	December 31,	
	2016	2015
Accounts and other receivables, net		
Trade receivables	$ 217,741	$ 263,384
Allowance for doubtful accounts	(99,606)	(110,251)
Trade receivables, net	118,135	153,133
Receivable from related parties	46,218	42,144
VAT receivables	5,802	10,798
Other	1,375	2,178
	$ 171,530	$ 208,253

Other current assets consisted of the following (in thousands):

	December 31,	
	2016	2015
Other current assets		
Deferred costs	$ 61,140	$ 86,803
Prepayments	18,810	18,399
Income tax receivable	7,200	-
Deferred financing fee	1,706	1,731
Restricted cash	626	5,985
Other	4,941	5,536
	$ 94,423	$ 118,454

Other assets consisted of the following (in thousands):

	December 31,	
	2016	2015
Other assets		
Deferred costs	$ 101,933	$ 122,420
Restricted cash	8,630	2,850
Retention receivable	4,148	3,503
Deposits	2,432	2,644
Deferred financing fee	568	2,289
Other	730	1,553
	$ 118,441	$ 135,259

Other current liabilities consisted of the following (in thousands):

	December 31, 2016	December 31, 2015
Other current liabilities		
Deferred revenue	$ 12,964	$ 18,566
Incentive compensation and bonus accruals	9,196	11,848
Accrued taxes, other than income	5,663	5,955
Accrued payroll and employee benefits	2,867	6,574
End of service benefits	1,274	2,989
Defined benefit obligation	481	739
Other	220	1
	$ 32,665	$ 46,672

Other long-term liabilities consisted of the following (in thousands):

	December 31, 2016	December 31, 2015
Other long-term liabilities		
Deferred revenue	$ 12,266	$ 15,729
End of service benefits	7,541	12,108
Defined benefit obligation	2,685	4,174
Income taxes	2,455	1,357
Other	250	233
	$ 25,197	$ 33,601

Note 20 — Supplemental Cash Flow Information

The net effect of changes in operating assets and liabilities on cash flows from operating activities was as follows (in thousands):

	Years ended December 31, 2016	2015	2014
Decrease / (increase) in operating assets			
Accounts and other receivables, net	$ 37,369	$ 28,865	$ 13,149
Other current assets	(6,716)	(25,956)	(1,208)
Other assets	1,469	35,410	23,988
(Decrease) / increase in operating liabilities			
Accounts payable and other current liabilities	(16,883)	(40,036)	(15,194)
Accrued interest	-	-	(114)
Accrued income taxes	(546)	(8,391)	2,487
Other long-term liabilities	4,426	2,248	11,268
	$ 19,119	$ (7,860)	$ 34,376

Additional cash flow information was as follows (in thousands):

	Years ended December 31, 2016	2015	2014
Cash payments for			
Interest, net of amounts capitalized	$ 37,414	$ 33,407	$ 39,965
Income taxes	26,125	40,669	45,958

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As part of the sale and leaseback agreements for the Newbuilds, contractual commitments totaling $148.1 million and $55.5 million were paid by third party financial institution directly to the Builder during the years ended December 31, 2016 and 2015, respectively, and $6.8 million and $643 thousand of interest in kind were recorded as obligations under sale and leaseback, respectively. Therefore, these non-cash transactions were not reflected on the consolidated statements of cash flows during the years ended December 31, 2016 and 2015. There were no such transactions for the year ended December 31, 2014.

The following table reconcile the cash payments related to additions to property and equipment and deferred costs to the total capital expenditures and deferred costs (in thousands):

	Years ended December 31,		
	2016	2015	2014
Cash payments for additions to property and equipment	$ 53,541	$ 157,193	$ 168,404
Net change in accrued but unpaid additions to property and equipment	(5,080)	(60,034)	23,004
	$ 48,461	$ 97,159	$ 191,408
Add: Asset addition related to sale and seaseback transactions	154,306	74,703	-
Total capital expenditures	$ 202,767	$ 171,862	$ 191,408
Cash payments for additions to deferred costs	$ 55,845	$ 161,553	$ 147,752
Net change in accrued but unpaid additions to deferred costs	(1,300)	(10,216)	(5,826)
Total deferred costs	$ 54,545	$ 151,337	$ 141,926
Total capital expenditures and deferred costs	$ 257,312	$ 323,199	$ 333,334

Note 21 — Related Parties

The Company has transactions with SDIL, Midco and SDL and these companies are related to the Company by common ownership. These transactions in which one entity pays expenses on behalf of the other entity result in related party receivable and payable balances. The Company has $46.2 million and $42.1 million as receivable under such transactions as of December 31, 2016 and December 31, 2015, respectively. The receivables are recorded in accounts and other receivables, net on the consolidated balance sheets. The Company has settled the outstanding balance of $46.2 million receivables in January 2017.

In connection with the Company's operations of a foreign subsidiary, a related party provided goods and services to drilling rigs owned by one of the Company's foreign subsidiaries. These goods and services totaled $3.3 million, $4.3 million and $5.9 million during 2016, 2015 and 2014, respectively.

The Company recorded $5.2 million, $5.1 million and 5.7 million during 2016, 2015 and 2014, respectively, for Sponsors' (affiliates of Castle Harlan, Inc., CHAMP Private Equity and Lime Rock Partners) costs related to the $375 thousand monthly fee, directors' fees and reimbursement of costs incurred by Sponsors and directors for attendance at meetings relating to the management and governance of the Company.

Note 22 — Dividends

During the years ended December 31, 2016, 2015 and 2014, the Company declared and paid dividends on its ordinary share totaling $135.6 million, $35.6 million and $156.8 million, respectively.

Note 23 — Comparative Information

The amortization of deferred costs, which was previously presented as part of the operating and maintenance expenses, has been presented as a separate line item in the consolidated statements of operations in the comparative years for 2015 and 2014 to conform with the current year presentation. These changes neither impact the financial position nor the cash flows of the Company.

The changes are as follows (in thousands):

	Year ended December 31, 2015		Year ended December 31, 2014	
	As previously presented	Reclassified amounts	As previously presented	Reclassified amounts
Operating costs and expenses				
Operating and maintenance	$ 615,140	$ 534,156	$ 715,971	$ 667,162
Amortization of deferred costs	-	80,984	-	48,809

Note 24 — Subsequent Events

On January 12, 2017 ("Closing Date"), the Company and its Parents successfully refinanced its long term debt and as a result, issued $502.835 million of new 9.5% Senior Secured Notes due November 2020 ("9.5% Senior Secured Notes"). These notes were issued in exchange and cancellation of $444.585 million of 8.625% Senior Secured Notes due November 2018 in accordance with the terms and conditions of the Offering Memorandum to Exchange Notes and Solicit Consents (of which $28.5 million were settled for cash), and $86.75 million in exchange for partial settlement of the $350 million Midco Term Loan. As of the Closing Date, $30.415 million of 8.625% Senior Secured Notes remain outstanding after issuance of $416.085 million 9.5% Senior Secured Notes, principal payment of $28.5 million in cash and incentive fee payment of $5.7 million in cash.

Simultaneously, the Company successfully amended the SDHL Revolver to extend the maturity date to April 2020, permanently reduce the facility from $200 million to $160 million and amend certain other terms of this agreement.

During January 2017, the Company has declared and paid dividend of $34.25 million to SDIL. This distribution was used to settle the intercompany receivable between SDHL and its Parents.