Transocean Ltd.
Form 10-K
March 07, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

(Mark one)

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

For the fiscal year ended December 31, 2016

OR

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

For the transition period from _____ to _____

Commission file number 000-53533

TRANSOCEAN LTD.

(Exact name of registrant as specified in its charter)

Zug, Switzerland	98-0599916

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
10 Chemin de Blandonnet Vernier, Switzerland	1214
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: +41 (22) 930-9000
Securities registered pursuant to Section 12(b) of the Act:

Title of class	Exchange on which registered
Shares, par value CHF 0.10 per share	New York Stock Exchange

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

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

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

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

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

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

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

Large accelerated filer Accelerated filer Non accelerated filer (do not check if a smaller reporting company) Smaller reporting company

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

As of June 30, 2016, 365,353,527 shares were outstanding and the aggregate market value of shares held by non affiliates was approximately $4.3 billion (based on the reported closing market price of the shares of Transocean Ltd. on June 30, 2016 of $11.89 and assuming that all directors and executive officers of the Company are "affiliates," although the Company does not acknowledge that any such person is actually an "affiliate" within the meaning of the federal securities laws). As of February 28, 2017, 389,597,755 shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2016, for its 2017 annual general meeting of shareholders, are incorporated by reference into Part III of this Form 10 K.

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TRANSOCEAN LTD. AND SUBSIDIARIES

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FOR THE YEAR ENDED DECEMBER 31, 2016

Forward looking Information

The statements included in this annual report regarding future financial performance and results of operations and other statements that are not historical facts are forward looking statements within the meaning of Section 27A of the United States ("U.S.") Securities Act of 1933 and Section 21E of the U.S. Securities Exchange Act of 1934. Forward looking statements in this annual report include, but are not limited to, statements about the following subjects:

§ our results of operations and cash flow from operations, including revenues, revenue efficiency, costs and expenses;
§ the offshore drilling market, including the effects of declines in commodity prices, supply and demand, utilization rates, dayrates, customer drilling programs, stacking of rigs, reactivation of rigs, effects of new rigs on the market, the impact of enhanced regulations in the jurisdictions in which we operate and changes in the global economy or market outlook for our various geographical operating sectors and classes of rigs;
§ customer drilling contracts, including contract backlog, force majeure provisions, contract commencements, contract extensions, contract terminations, contract option exercises, contract revenues, early termination payments, indemnity provisions, contract awards and rig mobilizations;
§ liquidity and adequacy of cash flows for our obligations;
§ debt levels, including impacts of a financial and economic downturn, and interest rates;
§ newbuild, upgrade, shipyard and other capital projects, including completion, delivery and commencement of operation dates, expected downtime and lost revenue, the level of expected capital expenditures and the timing and cost of completion of capital projects;
§ effects of remediation efforts to address the material weakness discussed in "Part II. Item 9A. Controls and Procedures";
§ the cost and timing of acquisitions and the proceeds and timing of dispositions;
§ the optimization of rig based spending;
§ tax matters, including our effective tax rate, changes in tax laws, treaties and regulations, tax assessments and liabilities for tax issues, including those associated with our activities in Brazil, Nigeria, Norway, the United Kingdom ("U.K.") and the U.S.;
§ legal and regulatory matters, including results and effects of legal proceedings and governmental audits and assessments, outcomes and effects of internal and governmental investigations, customs and environmental matters;
§ insurance matters, including adequacy of insurance, renewal of insurance, insurance proceeds and cash investments of our wholly owned captive insurance company;
§ effects of accounting changes and adoption of accounting policies; and
§ investments in recruitment, retention and personnel development initiatives, pension plan and other postretirement benefit plan contributions, the timing of severance payments and benefit payments.

Forward looking statements in this annual report are identifiable by use of the following words and other similar expressions:

§ "anticipates"	§ "could"	§ "forecasts"	§ "might"	§ "projects"
§ "believes"	§ "estimates"	§ "intends"	§ "plans"	§ "scheduled"
§ "budgets"	§ "expects"	§ "may"	§ "predicts"	§ "should"

Such statements are subject to numerous risks, uncertainties and assumptions, including, but not limited to:

§ those described under “Item 1A. Risk Factors” in this annual report on Form 10 K;
§ the adequacy of and access to sources of liquidity;
§ our inability to obtain drilling contracts for our rigs that do not have contracts;
§ our inability to renew drilling contracts at comparable dayrates;
§ operational performance;
§ the cancellation of drilling contracts currently included in our reported contract backlog;
§ the effectiveness of our remediation efforts with respect to the material weakness discussed in “Part II. Item 9A. Controls and Procedures”;
§ losses on impairment of long lived assets;
§ shipyard, construction and other delays;
§ the results of meetings of our shareholders;
§ changes in political, social and economic conditions;
§ the effect and results of litigation, regulatory matters, settlements, audits, assessments and contingencies; and
§ other factors discussed in this annual report and in our other filings with the U.S. Securities and Exchange Commission (“SEC”), which are available free of charge on the SEC website at www.sec.gov.

The foregoing risks and uncertainties are beyond our ability to control, and in many cases, we cannot predict the risks and uncertainties that could cause our actual results to differ materially from those indicated by the forward looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those indicated. All subsequent written and oral forward looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward looking statements. Each forward looking statement speaks only as of the date of the particular statement. We expressly disclaim any obligations or undertaking to release publicly any updates or revisions to any forward looking statement to reflect any change in our expectations or beliefs with regard to the statement or any change in events, conditions or circumstances on which any forward looking statement is based, except as required by law.

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PART I

Item 1.Business

Overview

Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean," the "Company," "we," "us" or "our") is a leading international provider of offshore contract drilling services for oil and gas wells. As of February 9, 2017, we owned or had partial ownership interests in and operated 56 mobile offshore drilling units. As of February 9, 2017, our fleet consisted of 30 ultra deepwater floaters, seven harsh environment floaters, three deepwater floaters, six midwater floaters and 10 high specification jackups. At February 9, 2017, we also had four ultra deepwater drillships and five high specification jackups under construction or under contract to be constructed.

Our primary business is to contract our drilling rigs, related equipment and work crews predominantly on a dayrate basis to drill oil and gas wells. We specialize in technically demanding regions of the global offshore drilling business with a particular focus on deepwater and harsh environment drilling services. We believe our mobile offshore drilling fleet is one of the most versatile fleets in the world, consisting of floaters and high specification jackups used in support of offshore drilling activities and offshore support services on a worldwide basis.

Transocean Ltd. is a Swiss corporation with its registered office in Steinhausen, Canton of Zug and with principal executive offices located at Chemin de Blandonnet 10, 1214 Vernier, Switzerland. Our telephone number at that address is +41 22 930 9000. Our shares are listed on the New York Stock Exchange under the symbol "RIG" (see "—Recent Developments"). For information about the revenues, operating income, assets and other information related to our business, our segments and the geographic areas in which we operate, see "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 21—Operating Segments, Geographic Analysis and Major Customers."

Recent Developments

Transocean Partners—On December 9, 2016, Transocean Partners LLC ("Transocean Partners") completed a merger with one of our subsidiaries as contemplated under the Agreement and Plan of Merger (the "Merger Agreement"), dated July 31, 2016, and as amended on November 21, 2016. Following the completion of the merger, Transocean Partners became a wholly owned indirect subsidiary of Transocean Ltd. Each Transocean Partners common unit that was issued and outstanding immediately prior to the closing, other than the units held by Transocean and its subsidiaries, was converted into the right to receive 1.20 of our shares. To complete the merger, we issued 23.8 million shares from conditional capital.

Markets for our shares—Our shares were previously listed on the SIX Swiss Exchange ("SIX") under the symbol "RIGN". Effective March 31, 2016, at our request, our shares were delisted from the SIX.

Drilling Fleet

Fleet overview—Our drilling fleet can be generally characterized as follows: (1) floaters, including drillships and semisubmersibles, and (2) jackups. Most of our drilling equipment is suitable for both exploration and development, and we normally engage in both types of drilling activity. All of our drilling rigs are mobile and can be moved to new locations in response to customer demand. All of our mobile offshore drilling units are designed to operate in locations away from port for extended periods of time and have living quarters for the crews, a helicopter landing deck and storage space for drill pipe, riser and drilling supplies.

Drillships are generally self propelled vessels, shaped like conventional ships, and are the most mobile of the major rig types. All of our drillships are ultra deepwater capable and equipped with a computer controlled dynamic positioning thruster system, which allows them to maintain position without anchors through the use of their onboard propulsion and station keeping systems. These rigs typically have greater deck load and storage capacity than early generation semisubmersible rigs, which provides logistical and resupply efficiency benefits for customers. Drillships are generally better suited to operations in calmer sea conditions and typically do not operate in areas considered to be harsh environments. We have 15 ultra deepwater drillships that are, and four ultra deepwater drillships under construction that will be, equipped with our patented dual activity technology. Dual activity technology employs structures, equipment and techniques using two drilling stations within a dual derrick to allow these drillships to perform simultaneous drilling tasks in a parallel, rather than a sequential manner, reducing critical path activity, to improve efficiency in both exploration and development drilling. In addition to dynamic positioning thruster systems, dual activity technology, industry leading hoisting capacity and a second blowout preventer system, our four newbuild drillships under construction will be outfitted to accommodate a future upgrade to a 20,000 pounds per square inch (“psi”) blowout preventer.

Semisubmersibles are floating vessels that can be partially submerged by means of a water ballast system such that the lower column sections and pontoons are below the water surface during drilling operations. These rigs are capable of maintaining their position over a well through the use of an anchoring system or a computer controlled dynamic positioning thruster system. Although most semisubmersible rigs are relocated with the assistance of tugs, some units are self propelled and move between locations under their own power when afloat on pontoons. Typically, semisubmersibles are capable of operating in rougher sea conditions than drillships. We have

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two custom designed, high capacity, dual activity semisubmersible drilling rigs, equipped for year round operations in harsh environments, including those of the Norwegian continental shelf and sub Arctic waters. We have three semisubmersibles that are designed for mild environments and are equipped with the tri act derrick. The tri act derrick, which was designed to reduce overall well construction costs since it allows offline tubular and riser handling operations to occur at two sides of the derrick while the center portion of the derrick is being used for normal drilling operations through the rotary table. Five of our 23 semisubmersibles are equipped with our patented dual activity technology.

Jackup rigs are mobile self elevating drilling platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the drilling platform. Once a foundation is established, the drilling platform is then jacked further up the legs so that the platform is above the highest expected waves. These rigs are generally suited for water depths of 400 feet or less. We have five newbuild high specification jackups under construction that are expected to be capable of constructing wells up to 35,000 feet deep and feature advanced offshore drilling technology, including offline tubular handling features and simultaneous operations support.

Fleet categories—We further categorize the drilling units of our fleet as follows: (1) “ultra deepwater floaters,” (2) “harsh environment floaters,” (3) “deepwater floaters,” (4) “midwater floaters” and (5) “high specification jackups.”

Ultra deepwater floaters are equipped with high pressure mud pumps and are capable of drilling in water depths of 7,500 feet or greater. Harsh environment floaters are capable of drilling in harsh environments in water depths between 1,500 and 10,000 feet and have greater displacement, which offers larger variable load capacity, more useable deck space and better motion characteristics. Deepwater floaters are generally those other semisubmersible rigs and drillships capable of drilling in water depths between 4,500 and 7,500 feet. Midwater floaters are generally comprised of those non high specification semisubmersibles that have a water depth capacity of less than 4,500 feet. High specification jackups have high capacity derricks, drawworks, mud systems and storage and generally have a water depth capacity of between 350 and 400 feet.

As of February 9, 2017, we owned and operated a fleet of 56 rigs, excluding rigs under construction, as follows:

§ 30 ultra deepwater floaters;
§ Seven harsh environment floaters;
§ Three deepwater floaters;
§ Six midwater floaters; and
§ 10 high specification jackups.

Fleet status—Depending on market conditions, we may idle or stack non contracted rigs. An idle rig is between drilling contracts, readily available for operations, and operating costs are typically at or near normal levels. A stacked rig typically has reduced operating costs, is staffed by a reduced crew or has no crew and is (a) preparing for an extended period of inactivity, (b) expected to continue to be inactive for an extended period, or (c) completing a period of extended inactivity. Stacked rigs will continue to incur operating costs at or above normal operating levels for approximately 30 days following initiation of stacking. Some idle rigs and all stacked rigs require additional costs to return to service. The actual cost to return to service, which in many instances could be significant and could fluctuate over time, depends upon various factors, including the availability and cost of shipyard facilities, cost of equipment and materials and the extent of repairs and maintenance that may ultimately be required. We consider these factors, together with market conditions, length of contract, dayrate and other contract terms, when deciding whether to return a stacked rig to service. We may, from time to time, consider marketing stacked rigs as accommodation units or for other alternative uses until drilling activity increases and we obtain drilling contracts for these units. We may not return some stacked rigs to work for drilling services or for these alternative uses.

Drilling units—The following tables, presented as of February 9, 2017, provide certain specifications for our rigs. Unless otherwise noted, the stated location of each rig indicates either the current drilling location, if the rig is operating, or the next operating location, if the rig is in shipyard with a follow on contract. As of February 9, 2017, we owned all of the drilling rigs in our fleet noted in the tables below, except for the following: (1) those specifically described as being owned through our interests in consolidated entities that were less than wholly owned and (2) Petrobras 10000, which is subject to a capital lease through August 2029.

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Rigs under construction (9)

Name	Type	Expected completion	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or contracted status
Ultra-deepwater floaters					
Deepwater Pontus (a) (b) (c) (d) (e)	HSD	4Q 2017	12,000	40,000	To be determined
Deepwater Poseidon (a) (b) (c) (d) (e)	HSD	1Q 2018	12,000	40,000	To be determined
Ultra-deepwater drillship TBN1 (a) (b) (d) (e)	HSD	1Q 2020	12,000	40,000	Uncontracted
Ultra-deepwater drillship TBN2 (a) (b) (d) (e)	HSD	3Q 2020	12,000	40,000	Uncontracted
High-specification jackups					
Transocean Cassiopeia	Jackup	1Q 2020	400	35,000	Uncontracted
Transocean Centaurus	Jackup	2Q 2020	400	35,000	Uncontracted
Transocean Cepheus	Jackup	3Q 2020	400	35,000	Uncontracted
Transocean Cetus	Jackup	4Q 2020	400	35,000	Uncontracted
Transocean Circinus	Jackup	4Q 2020	400	35,000	Uncontracted

"HSD" means high specification drillship.

(a)To be dynamically positioned.

(b)To be equipped with dual activity.

(c)To be an Enterprise class or Enhanced Enterprise class rig.

(d)Designed to accommodate a future upgrade to a 20,000 pounds psi blowout preventer.

(e)To be equipped with two blowout preventers.

Ultra deepwater floaters (30)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or standby status
Deepwater Conqueror (b) (c) (d) (e) (f)	HSD	2016	12,000	40,000	U.S. Gulf
Deepwater Proteus (b) (c) (d) (e) (f)	HSD	2016	12,000	40,000	U.S. Gulf
Deepwater Thalassa (b) (c) (d) (e) (f)	HSD	2016	12,000	40,000	U.S. Gulf
Deepwater Asgard (b) (c) (d) (f)	HSD	2014	12,000	40,000	Idle
Deepwater Invictus (b) (c) (d) (f)	HSD	2014	12,000	40,000	U.S. Gulf
Deepwater Champion (b) (c)	HSD	2011	12,000	40,000	Stacked
Discoverer Inspiration (b) (c) (d) (f)	HSD	2010	12,000	40,000	U.S. Gulf
Discoverer India (b) (c) (d)	HSD	2010	12,000	40,000	Idle

Discoverer Americas (b) (c) (d)	HSD	2009	12,000	40,000	Stacked
Discoverer Clear Leader (b) (c) (d) (f)	HSD	2009	12,000	40,000	U.S. Gulf
Petrobras 10000 (b) (c)	HSD	2009	12,000	37,500	Brazil
Dhirubhai Deepwater KG2 (b)	HSD	2010	12,000	35,000	Mayanmar
Dhirubhai Deepwater KG1 (b)	HSD	2009	12,000	35,000	Brazil
Discoverer Deep Seas (b) (c) (d)	HSD	2001	10,000	35,000	Stacked
Discoverer Spirit (b) (c) (d)	HSD	2000	10,000	35,000	Stacked
GSF C.R. Luigs (b)	HSD	2000	10,000	35,000	Stacked
GSF Jack Ryan (b)	HSD	2000	10,000	35,000	Stacked
Discoverer Enterprise (b) (c) (d)	HSD	1999	10,000	35,000	Stacked
Deepwater Discovery (b)	HSD	2000	10,000	30,000	Stacked
Deepwater Frontier (b)	HSD	1999	10,000	30,000	Stacked
Deepwater Millennium (b)	HSD	1999	10,000	30,000	Stacked
Deepwater Pathfinder (b)	HSD	1998	10,000	30,000	Stacked
Cajun Express (b) (g)	HSS	2001	8,500	35,000	Stacked
Deepwater Nautilus (h)	HSS	2000	8,000	30,000	Malaysia
Discoverer Luanda (b) (c) (d) (h)	HSD	2010	7,500	40,000	Angola
Development Driller III (b) (c)	HSS	2009	7,500	37,500	Idle
GSF Development Driller II (b) (c)	HSS	2005	7,500	37,500	Stacked
GSF Development Driller I (b) (c)	HSS	2005	7,500	37,500	Stacked
Sedco Energy (b) (g)	HSS	2001	7,500	35,000	Stacked
Sedco Express (b) (g)	HSS	2001	7,500	35,000	Stacked

"HSD" means high specification drillship.

"HSS" means high specification semisubmersible.

(a) Dates shown are the original service date and the date of the most recent upgrade, if any.
(b) Dynamically positioned.
(c) Dual activity.
(d) Enterprise class or Enhanced Enterprise class rig.
(e) Designed to accommodate a future upgrade to a 20,000 pounds psi blowout preventer.
(f) Two blowout preventers.
(g) Tri act derrick.
(h) Owned through our 65 percent interest in Angola Deepwater Drilling Company Limited ("ADDCL").

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Harsh environment floaters (7)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or standby status
Transocean Spitsbergen (b) (c)	HSS	2010	10,000	30,000	U.K. N. Sea
Transocean Barents (b) (c)	HSS	2009	10,000	30,000	Canada
Henry Goodrich (d)	HSS	1985/2007	5,000	30,000	Canada
Transocean Leader (d)	HSS	1987/1997	4,500	25,000	U.K. N. Sea
Paul B, Loyd, Jr.(d)	HSS	1990	2,000	25,000	U.K. N. Sea
Transocean Arctic (d)	HSS	1986	1,650	25,000	Norwegian N. Sea
Polar Pioneer (d)	HSS	1985	1,500	25,000	Stacked

"HSS" means high specification semisubmersible.

(a) Dates shown are the original service date and the date of the most recent upgrade, if any.
(b) Dynamically positioned.
(c) Dual activity.
(d) Moored floater.

Deepwater floaters (3)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or standby status
Transocean Marianas (b)	HSS	1979/1998	7,000	30,000	Stacked
Transocean 706 (c)	HSS	1976/2008	6,500	25,000	Brazil
Jack Bates (b)	HSS	1986/1997	5,400	30,000	India

"HSS" means high specification semisubmersible.

(a) Dates shown are the original service date and the date of the most recent upgrade, if any.
(b) Moored floater.
(c) Dynamically positioned.

Midwater floaters (6)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or standby status
Sedco 711	OS	1982	1,800	25,000	Stacked
Sedco 714	OS	1983/1997	1,600	25,000	Stacked
Sedco 712	OS	1983	1,600	25,000	U.K. N. Sea
Actinia	OS	1982	1,500	25,000	India

Transocean Prospect	OS	1983/1992	1,500	25,000	Stacked
Transocean Searcher	OS	1983/1988	1,500	25,000	Stacked

"OS" means other semisubmersible.

(a) Dates shown are the original service date and the date of the most recent upgrade, if any.

High specification jackups (10)

Name	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location or standby status
Transocean Ao Thai	2013	350	35,000	Thailand
Transocean Andaman	2013	350	35,000	Thailand
Transocean Siam Driller	2013	350	35,000	Thailand
Transocean Honor	2012	400	30,000	Stacked
GSF Constellation II	2004	400	30,000	Stacked
GSF Constellation I	2003	400	30,000	U.A.E.
GSF Galaxy I	1991/2001	400	30,000	U.K. N. Sea
GSF Galaxy III	1999	400	30,000	Stacked
GSF Galaxy II	1998	400	30,000	Stacked
GSF Monarch	1986	350	30,000	Stacked

(a) Dates shown are the original service date and the date of the most recent upgrades, if any.

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Markets

Our operations are geographically dispersed in oil and gas exploration and development areas throughout the world. We operate in a single, global offshore drilling market, as our drilling rigs are mobile assets and are able to be moved according to prevailing market conditions. We may mobilize our drilling rigs between regions for a variety of reasons, including to respond to customer contracting requirements or capture demand in another locale. Consequently, we cannot predict the percentage of our revenues that will be derived from particular geographic or political areas in future periods.

As of February 9, 2017, our drilling fleet was located in the U.K. North Sea (11 units), U.S. Gulf of Mexico (nine units), Trinidad (nine units), Spain (four units), Brazil (three units), Malaysia (three units), Norway (three units). Thailand (three units), Canada (two units), Congo (two units), India (two units), Angola (one unit), Myanmar (one unit), Romania (one unit), South Africa (one unit) and United Arab Emirates (one unit).

We categorize the market sectors in which we operate as follows: (1) ultra-deepwater, (2) deepwater, (3) midwater and (4) jackup. The ultra deepwater, deepwater and midwater market sectors, collectively known as the floater market, are serviced by our drillships and semisubmersibles, seven of which are suited to work in harsh environments. We generally view the ultra-deepwater market sector as water depths beginning at 7,500 feet and extending to the maximum water depths in which rigs are capable of drilling, which is currently up to 12,000 feet. The deepwater market sector services water depths beginning at approximately 4,500 feet to approximately 7,500 feet, and the midwater market sector services water depths from approximately 300 feet to approximately 4,500 feet. The jackup market sector begins at the outer limit of the transition zone, which is characterized by coastal and state water areas, extending to water depths of approximately 400 feet.

The market for offshore drilling rigs and related services reflects oil companies' demand for equipment for drilling exploration, appraisal and development wells and for performing maintenance on existing production wells. Activity levels of exploration and production ("E&P") companies and their associated capital expenditures are largely driven by the worldwide demand for energy, including crude oil and natural gas. Worldwide energy supply and demand drives oil and natural gas prices, which, in turn, impact E&P companies' ability to fund investments in exploration, development and production activities.

The industry is presently experiencing a cyclical downturn. Sustained weak commodity pricing has resulted in our customers delaying investment decisions and postponing exploration and production programs. Although oil and natural gas prices have improved recently, such prices do not currently support sustained demand for drilling rigs across all asset classes and regions. As a result of this reduced demand, we have observed a sharp decline in the execution of drilling contracts for the global offshore drilling fleet and an unprecedented level of drilling contract early terminations and cancellations. We currently expect few drilling contracts to be awarded in 2017, exacerbating the excess rig capacity and resulting in continued downward pressure on dayrates. In this environment, older and less capable assets are more likely to be permanently retired, ultimately reducing the available supply of drilling rigs. During the years ended December 31, 2016, 2015 and 2014, we sold for scrap value 11, 17 and two drilling units, respectively, and at December 31, 2016, we had one additional rig classified as held for sale for scrap value.

Despite current market conditions, our long term outlook for the offshore drilling sector remains positive, particularly for high specification assets. Prior to the downturn, Brazil, the U.S. Gulf of Mexico, and West Africa emerged as key ultra deepwater market sectors, and licensing activity demonstrated an increased interest in deepwater fields as E&P companies looked to explore new prospects. We expect deepwater oil and gas production will continue to be a part of the long term strategy for E&P companies as they strive to replace reserves to meet global demand for hydrocarbons. A number of new deepwater and ultra deepwater development opportunities have been identified globally. If commodity prices stabilize and rebound to sustainable levels, we anticipate that many of the projects will receive approval to move forward. Typically, these projects are technically demanding due to factors such as water depth, complex well designs, deeper drilling depth, high pressure and temperature, sub salt, harsh environments, and heightened regulatory standards; therefore, they require sophisticated drilling units. Generally, ultra deepwater rigs are the most modern, technologically advanced class of the offshore fleet and have capabilities that are attractive to E&P companies operating in deeper water depths, other challenging environments or with complex well designs.

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Financial Information about Geographic Areas

The following table presents the geographic areas in which our operating revenues were earned (in millions):

	Years ended December 31,		
	2016	2015	2014
Operating revenues			
U.S.	$ 1,977	$ 2,416	$ 2,410
U.K.	551	1,139	1,194
Brazil	453	673	651
Norway	214	650	1,036
Other countries (a)	966	2,508	3,894
Total operating revenues	$ 4,161	$ 7,386	$ 9,185

(a) Other countries represents countries in which we operate that individually had operating revenues representing less than 10 percent of total operating revenues earned for any of the periods presented.

The following table presents the geographic areas in which our long lived assets were located (in millions):

	December 31,	
	2016	2015
Long-lived assets		
U.S.	$ 6,181	$ 7,451
Trinidad	3,977	1,766
Korea	1,459	2,048
Other countries (a)	9,476	9,544
Total long-lived assets	$ 21,093	$ 20,809

(a) Other countries represents countries in which we operate that individually had long lived assets representing less than 10 percent of total long lived assets for any of the periods presented.

Contract Drilling Services

Our contracts to provide offshore drilling services are individually negotiated and vary in their terms and provisions. We obtain most of our drilling contracts through competitive bidding against other contractors and direct negotiations with operators. Drilling contracts generally provide for payment on a dayrate basis, with higher rates for periods while the drilling unit is operating and lower rates or zero rates for periods of mobilization or when drilling operations are interrupted or restricted by equipment breakdowns, adverse environmental conditions or other conditions beyond our control.

A dayrate drilling contract generally extends over a period of time covering either the drilling of a single well or group of wells or covering a stated term. At December 31, 2016, the contract backlog was approximately $11.7 billion, representing a decrease of 27 percent and 48 percent, respectively, compared to the contract backlog at December 31, 2015 and 2014, which was $16.0 billion and $22.5 billion, respectively. See “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Drilling market” and “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Performance and Other Key Indicators.”

Certain of our drilling contracts may be cancelable for the convenience of the customer upon payment of an early termination payment. Such payments, however, may not fully compensate us for the loss of the contract. Contracts also customarily provide for either automatic termination or termination at the option of the customer, typically without the payment of any termination fee, under various circumstances such as non performance, in the event of extended downtime or impaired performance caused by equipment or operational issues, or periods of extended downtime due to force majeure events. Many of these events are beyond our control. The contract term in some instances may be extended by the customer exercising options for the drilling of additional wells or for an additional term. Our contracts also typically include a provision that allows the customer to extend the contract to finish drilling a well in progress. During periods of depressed market conditions, our customers may seek to renegotiate firm drilling contracts to reduce the term of their obligations or the average dayrate through term extensions, or may seek to repudiate their contracts. Suspension of drilling contracts will result in the reduction in or loss of dayrate for the period of the suspension. If our customers cancel some of our contracts and we are unable to secure new contracts on a timely basis and on substantially similar terms, or if contracts are suspended for an extended period of time or if a number of our contracts are renegotiated, it could adversely affect our consolidated results of operations or cash flows. See "Item 1A. Risk Factors—Risks related to our business—Our drilling contracts may be terminated due to a number of events, and, during depressed market conditions, our customers may seek to repudiate or renegotiate their contracts."

Consistent with standard industry practice, our customers generally assume, and indemnify us against, well control and subsurface risks under dayrate drilling contracts. Under all of our current drilling contracts, our customers, as the operators, indemnify us for pollution damages in connection with reservoir fluids stemming from operations under the contract and we indemnify the operator for pollution from substances in our control that originate from the rig, such as diesel used onboard the rig or other fluids stored onboard the rig and above the

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water surface. Also, under all of our current drilling contracts, the operator indemnifies us against damage to the well or reservoir and loss of subsurface oil and gas and the cost of bringing the well under control. However, our drilling contracts are individually negotiated, and the degree of indemnification we receive from the operator against the liabilities discussed above can vary from contract to contract, based on market conditions and customer requirements existing when the contract was negotiated. In some instances, we have contractually agreed upon certain limits to our indemnification rights and can be responsible for damages up to a specified maximum dollar amount, which is, in any case, immaterial to us. The nature of our liability and the prevailing market conditions, among other factors, can influence such contractual terms. In most instances in which we are indemnified for damages to the well, we have the responsibility to redrill the well at a reduced dayrate. Notwithstanding a contractual indemnity from a customer, there can be no assurance that our customers will be financially able to indemnify us or will otherwise honor their contractual indemnity obligations. See "Item 1A. Risk Factors—Risks related to our business—Our business involves numerous operating hazards, and our insurance and indemnities from our customers may not be adequate to cover potential losses from our operations."

The interpretation and enforceability of a contractual indemnity depends upon the specific facts and circumstances involved, as governed by applicable laws, and may ultimately need to be decided by a court or other proceeding, which will need to consider the specific contract language, the facts and applicable laws. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy. Courts also restrict indemnification for criminal fines and penalties. The inability or other failure of our customers to fulfill their indemnification obligations, or unenforceability of our contractual protections could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies."

Significant Customers

We engage in offshore drilling services for most of the leading international oil companies or their affiliates, as well as for many government controlled oil companies and independent oil companies. For the year ended December 31, 2016, our most significant customers were Chevron Corporation (together with its affiliates, "Chevron"), BP plc. (together with its affiliates, "BP"), Royal Dutch Shell plc (together with its affiliates, "Shell") and Petróleo Brasileiro S.A. ("Petrobras"), representing approximately 24 percent, 12 percent, 12 percent and 11 percent, respectively, of our consolidated operating revenues. No other customers accounted for 10 percent or more of our consolidated operating revenues in the year ended December 31, 2016. Additionally, as of February 9, 2017, the customers with the most significant aggregate amount of contract backlog associated with our drilling contracts were Shell and Chevron, representing approximately 63 percent and 20 percent, respectively, of our total contract backlog. See "Item 1A. Risk Factors—Risks related to our business—We rely heavily on a relatively small number of customers and the loss of a significant customer or a dispute that leads to the loss of a customer could have a material adverse impact on our consolidated statement of financial position, results of operations or cash flows."

Employees

We require highly skilled personnel to operate our drilling units. Consequently, we conduct extensive personnel recruiting, training and safety programs. At December 31, 2016, we had approximately 5,400 employees, including approximately 400 persons engaged through contract labor providers. Approximately 28 percent of our total workforce, working primarily in Angola, Brazil, Norway and the U.K. are represented by, and some of our contracted labor work under, collective bargaining agreements, substantially all of which are subject to annual salary negotiation. These negotiations could result in higher personnel expenses, other increased costs or increased operational restrictions, as the outcome of such negotiations apply to all offshore employees not just the union members. Additionally, failure to reach agreement on certain key issues may result in strikes, lockouts or other work stoppages that may materially impact our operations.

Joint Venture, Agency and Sponsorship Relationships and Other Investments

In some areas of the world, local customs and practice or governmental requirements necessitate the formation of joint ventures with local participation. We may or may not control these joint ventures. We are an active participant in several joint venture drilling companies, principally in Angola, Indonesia, Malaysia and Nigeria. Local laws or customs in some areas of the world also effectively mandate establishment of a relationship with a local agent or sponsor. When appropriate in these areas, we enter into agency or sponsorship agreements. At December 31, 2016, joint ventures in which we participate were as follows:

We hold a 65 percent interest in ADDCL, a consolidated Cayman Islands joint venture company formed to own Discoverer Luanda, which operates in Angola. Our local partner, Angco Cayman Limited, a Cayman Islands company, holds the remaining 35 percent interest in ADDCL. Angco Cayman Limited has the right to exchange its interest in the joint venture for cash at an amount based on an appraisal of the fair value of the drillship, subject to certain adjustments.

We hold a 24 percent direct interest and a 36 percent indirect interest in Indigo Drilling Limited (“Indigo”), a consolidated Nigerian joint venture company formed to engage in drilling operations offshore Nigeria. Our local partners, Mr. Fidelis Oditah and Mr. Chima Ibeneche, each hold a 12.5 percent direct interest, and our other partners, Mr. Joseph Obi and Mr. Ben Osuno, together own a 15 percent indirect interest, in Indigo.

Additionally, we hold interests in certain joint venture companies in Angola, Indonesia, Malaysia, Nigeria and other countries that have been formed to perform certain management services and other onshore support services for our operations.

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Technological Innovation

Since launching the offshore industry's first jackup drilling rig in 1954, we have achieved a long history of technological innovations, including the first dynamically positioned drillship, the first rig to drill year round in the North Sea and the first semisubmersible rig for year round sub Arctic operations. We have repeatedly achieved water depth world records in the past. Twenty drillships and semisubmersibles in our existing fleet are, and our four drillships that are under construction will be, equipped with our patented dual activity technology, which allows our rigs to perform simultaneous drilling tasks in a parallel rather than sequential manner and reduces critical path activity while improving efficiency in both exploration and development drilling. Additionally, three rigs in our existing fleet are equipped with the tri act derrick, which allows offline tubular and riser activities during normal drilling operations and is patented in certain market sectors in which we operate.

We continue to develop and deploy industry leading technology. In addition to our patented dual activity drilling technology, some of our most recent newbuild drillships include industry leading hookload capability, compensated cranes for performing subsea installations, hybrid power systems and reduced emissions and advanced generator protection. Seven drillships in our existing fleet are, and our four drillships that are under construction will be, outfitted with two blowout preventers and triple liquid mud systems. Three drillships in our existing fleet are, and our four drillships that are under construction will be, designed to accept 20,000 psi blowout preventers in the future. The effective use of and continued improvements in technology to address our customers' requirements are critical to maintaining our competitive position within the contract drilling services industry. We continue to develop technology internally, such as the digital transformation program focused on utilizing analytics and data science to continuously improve operational integrity and efficiency while optimizing cost. In addition, we are focused on a breakthrough drilling innovation program that includes a fault resistant and fault tolerant blowout preventer control system.

Environmental Compliance

Our operations are subject to a variety of global environmental regulations. We monitor our compliance with environmental regulation in each country of operation and, while we see an increase in general environmental regulation, we have made and will continue to make the required expenditures to comply with current and future environmental requirements. We make expenditures to further our commitment to environmental improvement and the setting of a global environmental standard. We assess the environmental impacts of our business, focusing on the areas of greenhouse gas emissions, climate change, discharges and waste management. Our actions are designed to reduce risk in our current and future operations, to promote sound environmental management and to create a proactive environmental program. To date, we have not incurred material costs in order to comply with recent environmental legislation, and we do not believe that our compliance with such requirements will have a material adverse effect on our competitive position, consolidated results of operations or cash flows. For a discussion of the effects of environmental regulation, see "Item 1A. Risk Factors—Risks related to our business—Compliance with or breach of environmental laws can be costly, expose us to liability and could limit our operations."

Available Information

Our website address is www.deepwater.com. Information contained on or accessible from our website is not incorporated by reference into this annual report on Form 10 K and should not be considered a part of this report or any other filing that we make with the SEC. We make available on this website free of charge, our annual reports on Form 10 K, quarterly reports on Form 10 Q, current reports on Form 8 K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. You may also find on our website information related to our corporate governance, board committees and company code of business conduct and ethics. The SEC also maintains a website, www.sec.gov, which contains reports, proxy statements and other information regarding SEC registrants, including us.

We intend to satisfy the requirement under Item 5.05 of Form 8 K to disclose any amendments to our Code of Integrity and any waiver from any provision of our Code of Integrity by posting such information in the Governance page on our website at www.deepwater.com.

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Item 1A.Risk Factors

Risks related to our business

§ Our business depends on the level of activity in the offshore oil and gas industry, which is significantly affected by volatile oil and gas prices and other factors.

Our business depends on the level of activity in oil and gas exploration, development and production in offshore areas worldwide. Demand for our services depends on oil and natural gas industry activity and expenditure levels that are directly affected by trends in oil and, to a lesser extent, natural gas prices. Oil and gas prices are extremely volatile and are affected by numerous factors, including the following:

§ worldwide demand for oil and gas, including economic activity in the U.S. and other large energy consuming markets;
§ the ability of the Organization of the Petroleum Exporting Countries ("OPEC") to set and maintain production levels, productive spare capacity and pricing;
§ the level of production in non OPEC countries;
§ the policies of various governments regarding exploration and development of their oil and gas reserves;
§ international sanctions on oil producing countries, or the lifting of such sanctions;
§ advances in exploration, development and production technology;
§ the further development of shale technology to exploit oil and gas reserves;
§ the discovery rate of new oil and gas reserves;
§ the rate of decline of existing oil and gas reserves;
§ laws and regulations related to environmental matters, including those addressing alternative energy sources and the risks of global climate change;
§ the development and exploitation of alternative fuels;
§ accidents, adverse weather conditions, natural disasters and other similar incidents relating to the oil and gas industry; and
§ the worldwide security and political environment, including uncertainty or instability resulting from an escalation or outbreak of armed hostilities, civil unrest or other crises in the Middle East or other geographic areas or acts of terrorism.

Demand for our services is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, oil and natural gas companies, including national oil companies. Any prolonged reduction in oil and natural gas prices could depress the immediate levels of exploration, development and production activity. Perceptions of longer term lower oil and natural gas prices by oil and gas companies could similarly reduce or defer major expenditures given the long term nature of many large scale development projects. Lower levels of activity result in a corresponding decline in the demand for our services, which could have a material adverse effect on our revenue and profitability. Oil and gas prices and market expectations of potential changes in these prices significantly affect this level of activity. However, increases in near term commodity prices do not necessarily translate into increased offshore drilling activity since customers' expectations of longer term future commodity prices typically drive demand for our rigs. The current commodity pricing environment has had a negative impact on demand for our services, and it could continue. The price of crude oil as reported on the New York Mercantile Exchange has weakened significantly and, despite recent price improvements, has not returned to the higher levels experienced prior to December 31, 2014. Consequently, customers have delayed or cancelled many exploration and development programs, resulting in reduced demand for our services. Also, increased competition for customers' drilling budgets could come from, among other areas, land based energy markets worldwide. The availability of quality drilling prospects, exploration success, relative production costs, the stage of reservoir development and political and regulatory environments also affect customers' drilling campaigns. Worldwide military, political and economic events have contributed to oil and gas price volatility and are likely to do so in the future.

§ The offshore drilling industry is highly competitive and cyclical, with intense price competition.
The offshore contract drilling industry is highly competitive with numerous industry participants, none of which has a dominant market share. Drilling contracts are traditionally awarded on a competitive bid basis. Although rig availability, service quality and technical capability are drivers of customer contract awards, bid pricing and intense price competition are often key determinants for which a qualified contractor is awarded a job.

The offshore drilling industry has historically been cyclical and is impacted by oil and natural gas price levels and volatility. There have been periods of high customer demand, limited rig supply and high dayrates, followed by periods of low customer demand, excess rig supply and low dayrates. Changes in commodity prices can have a dramatic effect on rig demand, and periods of excess rig supply may intensify competition in the industry and result in the idling of older and less technologically advanced equipment. We have idled and stacked rigs, and may in the future idle or stack additional rigs or enter into lower dayrate drilling contracts in response to market conditions. We cannot predict when or if any idled or stacked rigs will return to service.

During prior periods of high dayrates and rig utilization rates, we and other industry participants have responded to increased customer demand by increasing the supply of rigs through ordering the construction of new units. In periods of low oil and natural gas price levels, growth in new construction has historically resulted in an oversupply of rigs and has caused a subsequent decline in dayrates and rig utilization rates, sometimes for extended periods of time. Presently, there are numerous recently constructed high specification floaters and other drilling units capable of competing with our rigs that have entered the global market, and there are more that are under construction.

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The entry into service of these new units has increased and will continue to increase supply. The increased supply has contributed to and may continue to contribute to a reduction in dayrates as rigs are absorbed into the active fleet and has led to accelerated stacking of the existing fleet.

Two of our four ultra deepwater drillships and our five high specification jackups currently under construction have not been contracted for work. Combined with the rapid increase in the number of rigs in the global market completing contracts and becoming idle, the number of new units expected to be delivered without contracts has intensified and may further intensify price competition. Any further increase in construction of new units would likely exacerbate the negative impact of increased supply on dayrates and utilization rates. Additionally, lower market dayrates and intense price competition may drive customers to demand renegotiation of existing contracts to lower dayrates in exchange for longer contract terms. In an oversupplied market, we may have limited bargaining power to negotiate on more favorable terms. Lower dayrates and rig utilization rates could adversely affect our revenues and profitability.

§ Our drilling contracts may be terminated due to a number of events, and, during depressed market conditions, our customers may seek to repudiate or renegotiate their contracts.

Certain of our drilling contracts with customers may be cancelable at the option of the customer upon payment of an early termination payment. Such payments may not, however, fully compensate us for the loss of the contract. Drilling contracts also customarily provide for either automatic termination or termination at the option of the customer typically without the payment of any termination fee, under various circumstances such as non performance, as a result of significant downtime or impaired performance caused by equipment or operational issues, or sustained periods of downtime due to force majeure events. Many of these events are beyond our control. During periods of depressed market conditions, we are subject to an increased risk of our customers seeking to repudiate their contracts, including through claims of non performance. We are at continued risk of experiencing early contract terminations in the current weak commodity price environment as operators look to reduce their capital expenditures. During the years ended December 31, 2016 and 2015, our customers early terminated or cancelled contracts for eight and five of our rigs, respectively, and these rigs currently remain idle. Our customers' ability to perform their obligations under their drilling contracts, including their ability to fulfill their indemnity obligations to us, may also be negatively impacted by an economic downturn. Our customers, which include national oil companies, often have significant bargaining leverage over us. If our customers cancel some of our contracts, and we are unable to secure new contracts on a timely basis and on substantially similar terms, or if contracts are suspended for an extended period of time or if a number of our contracts are renegotiated, it could adversely affect our consolidated statement of financial position, results of operations or cash flows. See "Item 1. Business—Contract Drilling Services."

§ Our current backlog of contract drilling revenue may not be fully realized, which may have a material adverse impact on our consolidated statement of financial position, results of operations or cash flows.

At February 9, 2017, our contract backlog was approximately $11.3 billion. This amount represents the firm term of the drilling contract multiplied by the contractual operating rate, which may be higher than the actual dayrate we receive or we may receive other dayrates included in the contract, such as waiting on weather rate, repair rate, standby rate or force majeure rate. The contractual operating dayrate may also be higher than the actual dayrate we receive because of a number of factors, including rig downtime or suspension of operations.

Several factors could cause rig downtime or a suspension of operations, including:

§ breakdowns of equipment and other unforeseen engineering problems;
§ work stoppages, including labor strikes;
§ shortages of material and skilled labor;
§ surveys by government and maritime authorities;
§ periodic classification surveys;
§ severe weather, strong ocean currents or harsh operating conditions; and

§ force majeure events.

In certain drilling contracts, the dayrate may be reduced to zero or result in customer credit against future dayrate if, for example, repairs extend beyond a stated period of time. Our contract backlog includes signed drilling contracts and, in some cases, other definitive agreements awaiting contract execution. We may not be able to realize the full amount of our contract backlog due to events beyond our control. In addition, some of our customers have experienced liquidity issues in the past and these liquidity issues could be experienced again if commodity prices decline to lower levels for an extended period of time. Liquidity issues and other market pressures could lead our customers to go into bankruptcy or could encourage our customers to seek to repudiate, cancel or renegotiate these agreements for various reasons (see "—Our drilling contracts may be terminated due to a number of events, and, during depressed market conditions, our customers may seek to repudiate or renegotiate their contracts.") Our inability to realize the full amount of our contract backlog may have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

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§ We may not be able to renew or obtain new drilling contracts for rigs whose contracts are expiring or are terminated or obtain drilling contracts for our uncontracted newbuilds, which could adversely affect our consolidated statements of operations.

Our ability to renew expiring drilling contracts or obtain new drilling contracts will depend on the prevailing market conditions at the time. If we are unable to obtain new drilling contracts in direct continuation with existing contracts or for our uncontracted newbuild units, or if new drilling contracts are entered into at dayrates substantially below the existing dayrates or on terms otherwise less favorable compared to existing contract terms, our revenues and profitability could be adversely affected.

The offshore drilling markets in which we compete experience fluctuations in the demand for drilling services. A number of existing drilling contracts for our drilling rigs that are currently operating are scheduled to expire before December 31, 2017. Seven of the units we currently have under construction as part of our newbuild program, two ultra deepwater drillships and our five high specification jackups, are being constructed without customer drilling contracts. We will attempt to secure drilling contracts for these units prior to their completion. We may be unable to obtain drilling contracts for our rigs that are currently operating upon the expiration or termination of such contracts or obtain drilling contracts for our newbuilds, and there may be a gap in the operation of the rigs between the current contracts and subsequent contracts. In particular, if oil and natural gas prices remain low, as is currently the case, or it is expected that such prices will decrease in the future, at a time when we are seeking drilling contracts for our rigs, we may be unable to obtain drilling contracts at attractive dayrates or at all.

§ We must make substantial capital and operating expenditures to maintain our fleet, and we may be required to make significant capital expenditures to maintain our competitiveness and to comply with laws and the applicable regulations and standards of governmental authorities and organizations, or to execute our growth plan, each of which could negatively affect our financial condition, results of operations and cash flows.

We must make substantial capital and operating expenditures to maintain our fleet. These expenditures could increase as a result of changes in the following:

§ the cost of labor and materials;
§ customer requirements;
§ fleet size;
§ the cost of replacement parts for existing drilling rigs;
§ the geographic location of the drilling rigs;
§ length of drilling contracts;
§ governmental regulations and maritime self-regulatory organization and technical standards relating to safety, security or the environment; and
§ industry standards.

Changes in offshore drilling technology, customer requirements for new or upgraded equipment and competition within our industry may require us to make significant capital expenditures in order to maintain our competitiveness. In addition, changes in governmental regulations, safety or other equipment standards, as well as compliance with standards imposed by maritime self-regulatory organizations, may require us to make additional unforeseen capital expenditures. As a result, we may be required to take our rigs out of service for extended periods of time, with corresponding losses of revenues, in order to make such alterations or to add such equipment. In the future, market conditions may not justify these expenditures or enable us to operate our older rigs profitably during the remainder of their economic lives.

In addition, we may require additional capital in the future. If we are unable to fund capital expenditures with our cash flow from operations or sales of non-strategic assets, we may be required to either incur additional borrowings or raise capital through the sale of debt or equity securities. Our ability to access the capital markets may be limited by our financial condition at the time, by changes in laws and regulations or interpretation thereof and by adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control. If we raise funds by issuing equity securities, existing shareholders may experience dilution. Our failure to obtain the funds for necessary future capital expenditures could have a material adverse effect on our business and on our consolidated statements of financial condition, results of operations and cash flows.

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§ The recent downgrades in our credit ratings by various credit rating agencies could impact our access to capital and materially adversely affect our business and financial condition.

During the year ended December 31, 2015, three credit rating agencies downgraded their credit ratings of our non credit enhanced senior unsecured long term debt (“Debt Rating”) to Debt Ratings that are below investment grade. During the year ended December 31, 2016 and in January 2017, the same three credit rating agencies further downgraded our Debt Rating. Our Debt Rating levels could have material adverse consequences on our business and future prospects and could:

§ limit our ability to access debt markets, including for the purpose of refinancing our existing debt;

§ cause us to refinance or issue debt with less favorable terms and conditions, which debt may require collateral and restrict, among other things, our ability to pay distributions or repurchase shares;

§ increase certain fees under our credit facilities and interest rates under indentures governing certain of our senior notes;

§ negatively impact current and prospective customers’ willingness to transact business with us;

§ impose additional insurance, guarantee and collateral requirements;

§ limit our access to bank and third-party guarantees, surety bonds and letters of credit; and

§ suppliers and financial institutions may lower or eliminate the level of credit provided through payment terms or intraday funding when dealing with us thereby increasing the need for higher levels of cash on hand, which would decrease our ability to repay debt balances.

The downgrades have caused some of the effects listed above, and any further downgrades may cause or exacerbate, any of the effects listed above.

§ We have a substantial amount of debt, including secured debt, and we may lose the ability to obtain future financing and suffer competitive disadvantages.

At December 31, 2016 and 2015, our total consolidated debt was $8.5 billion. This substantial level of debt and other obligations could have significant adverse consequences on our business and future prospects, including the following:

§ we may be unable to obtain financing in the future for working capital, capital expenditures, acquisitions, debt service requirements, distributions, share repurchases, or other purposes;

§ we may be unable to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the debt;

§ we could become more vulnerable to general adverse economic and industry conditions, including increases in interest rates, particularly given our substantial indebtedness, some of which bears interest at variable rates;

§ we may be unable to meet financial ratios in the indentures governing certain of our debt or in our bank credit agreements or satisfy certain other conditions included in our bank credit agreements, which could result in our inability to meet requirements for borrowings under our credit agreements or a default under these indentures or agreements, impose restrictions with respect to our access to certain of our capital, and trigger cross default provisions in our other debt instruments;

§ if we default under the terms of our secured financing arrangements, the secured debtholders may, among other things, foreclose on the collateral securing the debt, including the applicable drilling units; and

§ we may be less able to take advantage of significant business opportunities and to react to changes in market or industry conditions than our less levered competitors.

See “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations—Liquidity and Captial Resources—Sources and Uses of Liquidity—Debt Issuances.”

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We rely heavily on a relatively small number of customers and the loss of a significant customer or a dispute that leads to the loss of a customer could have a material adverse impact on our consolidated statement of financial position, results of operations or cash flows.

We engage in offshore drilling services for most of the leading international oil companies or their affiliates, as well as for many government controlled oil companies and independent oil companies. For the year ended December 31, 2016, our most significant customers were Chevron, BP, Shell and Petrobras, accounting for approximately 24 percent, 12 percent, 12 percent and 11 percent, respectively, of our consolidated operating revenues. As of February 9, 2017, the customers with the most significant aggregate amount of contract backlog were Shell and Chevron, representing approximately 63 percent and 20 percent, respectively, of our total contract backlog. The loss of any of these customers or another significant customer, or a decline in payments under any of our drilling contracts, could, at least in the short term, have a material adverse effect on our results of operations and cash flows.

In addition, our drilling contracts subject us to counterparty risks. The ability of each of our counterparties to perform its obligations under a contract with us will depend on a number of factors that are beyond our control and may include, among other things, general economic conditions, the condition of the offshore drilling industry, prevailing prices for oil and natural gas, the overall financial condition of the counterparty, the dayrates received and the level of expenses necessary to maintain drilling activities. In addition, in depressed market conditions, such as we are currently experiencing, our customers may no longer need a drilling rig that is currently under contract or may be able to obtain a comparable drilling rig at a lower dayrate. Should a counterparty fail to honor its obligations under an agreement with us, we could sustain losses, which could have a material adverse effect on our business and on our consolidated statement of financial condition results of operations or cash flows.

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§ Worldwide financial, economic and political conditions could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Worldwide financial and economic conditions could restrict our ability to access the capital markets at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. Worldwide economic conditions have in the past impacted, and could in the future impact, the lenders participating in our credit facilities and our customers, causing them to fail to meet their obligations to us. If economic conditions preclude or limit financing from banking institutions participating in our credit facilities, we may not be able to obtain similar financing from other institutions. A slowdown in economic activity could further reduce worldwide demand for energy and extend or worsen the current period of low oil and natural gas prices. A further decline in oil and natural gas prices or an extension of the current low oil and natural gas prices could reduce demand for our drilling services and have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

The world economy is currently facing a number of challenges. An extended period of negative outlook for the world economy could reduce the overall demand for oil and natural gas and for our services. These potential developments, or market perceptions concerning these and related issues, could affect our consolidated statement of financial position, results of operations or cash flows. In addition, turmoil and hostilities in the Middle East, North Africa and other geographic areas and countries are adding to overall risk. An extended period of negative outlook for the world economy could further reduce the overall demand for oil and natural gas and for our services. Such changes could adversely affect our business and our consolidated statement of financial position, results of operations or cash flows.

§ Our operating and maintenance costs will not necessarily fluctuate in proportion to changes in our operating revenues.

Our operating and maintenance costs will not necessarily fluctuate in proportion to changes in our operating revenues. Costs for operating a rig are generally fixed or only semi variable regardless of the dayrate being earned. In addition, should our rigs incur unplanned downtime while on contract or idle time between drilling contracts, we will not always reduce the staff on those rigs because we could use the crew to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate because portions of the crew may be required to prepare rigs for stacking, after which time the crew members may be assigned to active rigs or released. As our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase primarily due to higher salary levels and inflation. Equipment maintenance costs fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment, and these costs could increase for short or extended periods as a result of regulatory or customer requirements that raise maintenance standards above historical levels. Contract preparation costs vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

§ Our shipyard projects and operations are subject to delays and cost overruns.

As of February 9, 2017, we had four ultra deepwater floater and five high specification jackup newbuild rigs under construction. We also have a variety of other more limited shipyard projects at any given time. These shipyard projects are subject to the risks of delay or cost overruns inherent in any such construction project resulting from numerous factors, including the following:

§ shipyard availability, failures and difficulties;
§ shortages of equipment, materials or skilled labor;
§ unscheduled delays in the delivery of ordered materials and equipment;
§ design and engineering problems, including those relating to the commissioning of newly designed equipment;
§ latent damages or deterioration to hull, equipment and machinery in excess of engineering estimates and assumptions;

- unanticipated actual or purported change orders;
- disputes with shipyards and suppliers;
- failure or delay of third-party vendors or service providers;
- availability of suppliers to recertify equipment for enhanced regulations;
- strikes, labor disputes and work stoppages;
- customer acceptance delays;
- adverse weather conditions, including damage caused by such conditions;
- terrorist acts, war, piracy and civil unrest;
- unanticipated cost increases; and
- difficulty in obtaining necessary permits or approvals.

These factors may contribute to cost variations and delays in the delivery of our newbuild units and other rigs undergoing shipyard projects. Delays in the delivery of these units would impact contract commencement, resulting in a loss of revenue to us, and may also cause customers to terminate or shorten the term of the drilling contract for the rig pursuant to applicable late delivery clauses. In the event of termination of any of these drilling contracts, we may not be able to secure a replacement contract on as favorable terms, if at all.

Our operations also rely on a significant supply of capital and consumable spare parts and equipment to maintain and repair our fleet. We also rely on the supply of ancillary services, including supply boats and helicopters. Shortages in materials, manufacturing defects, delays in the delivery of necessary spare parts, equipment or other materials, or the unavailability of ancillary services could negatively impact our future operations and result in increases in rig downtime and delays in the repair and maintenance of our fleet.

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§ We could experience a material adverse effect on our consolidated statement of financial position, results of operations or cash flows to the extent the Macondo well's operator fails to indemnify us or is otherwise unable to indemnify us for compensatory damages related to the Macondo well incident as required under the terms of our settlement agreement.

The combined response team to the Macondo well incident was unable to stem the flow of hydrocarbons from the well prior to the sinking of Deepwater Horizon. The resulting spill of hydrocarbons was the most extensive in U.S. history. Under the Deepwater Horizon drilling contract and in accordance with our settlement agreement with the operator, BP agreed to indemnify us with respect to certain matters, and we agreed to indemnify BP with respect to certain matters (see "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies—Macondo well incident commitments and contingencies—BP Settlement Agreement"). We could experience a material adverse effect on our consolidated statement of financial position, results of operations or cash flows to the extent that BP fails to fully satisfy its indemnification obligations, including by reason of financial or legal restrictions, or our insurance policies do not fully cover these amounts. In addition, in connection with our settlement with the Department of Justice (the "DOJ"), we agreed that we will not use payments pursuant to a civil consent decree by and among the DOJ and certain of our affiliates (the "Consent Decree") as a basis for indemnity or reimbursement from non insurer defendants named in the complaint by the U.S. or their affiliates.

§ Our agreement with the U.S. Environmental Protection Agency may prohibit us from entering into, extending or engaging in certain business relationships. In addition, if we do not comply with the terms of our agreement with the U.S. Environmental Protection Agency, we may be subject to suspension, debarment or statutory disqualification.

On February 25, 2013, we and the U.S. Environmental Protection Agency (the "EPA") entered into an administrative agreement (the "EPA Agreement") related to the Macondo well incident, which has a five year term. In the EPA Agreement, we agreed to, among other things, continue the implementation of certain programs and systems; comply with certain employment and contracting procedures; engage independent compliance auditors and a process safety consultant; and give reports and notices with respect to various matters. Subject to certain exceptions, the EPA Agreement prohibits us from entering into, extending or engaging in certain business relationships with individuals or entities that are debarred, suspended, proposed for debarment or similarly restricted. In addition, if we fail to comply with the terms of the EPA Agreement, we may be subject to suspension, debarment or statutory disqualification.

§ The continuing effects of the enhanced regulations enacted following the Macondo well incident and of agreements applicable to us could materially and adversely affect our worldwide operations.

Following the Macondo well incident, enhanced governmental safety and environmental requirements applicable to both deepwater and shallow water operations were adopted for drilling in the U.S. Gulf of Mexico. In order to obtain drilling permits, operators must submit applications that demonstrate compliance with the enhanced regulations, which require independent third party inspections, certification of well design and well control equipment and emergency response plans in the event of a blowout, among other requirements. Operators have previously had, and may in the future have, difficulties obtaining drilling permits in the U.S. Gulf of Mexico. In addition, the oil and gas industry has adopted new equipment and operating standards, such as the American Petroleum Institute Standard 53 related to the installation and testing of well control equipment. These new safety and environmental guidelines and standards and any further new guidelines or standards the U.S. government or industry may issue or any other steps the U.S. government or industry may take, could disrupt or delay operations, increase the cost of operations, increase out of service time or reduce the area of operations for drilling rigs in the U.S. and non U.S. offshore areas.

Other governments could take similar actions related to implementing new safety and environmental regulations in the future. Additionally, some of our customers have elected to voluntarily comply with some or all of the new inspections, certification requirements and safety and environmental guidelines on rigs operating outside of the

U.S. Gulf of Mexico. Additional governmental regulations and requirements concerning licensing, taxation, equipment specifications and training requirements or the voluntary adoption of such requirements or guidelines by our customers could increase the costs of our operations, increase certification and permitting requirements, increase review periods and impose increased liability on offshore operations. The requirements applicable to us under the Consent Decree and the EPA Agreement cover safety, environmental, reporting, operational and other matters and are in addition to the regulations applicable to other industry participants and may require additional agreements and corporate compliance resources that, together with our cooperation guilty plea agreement by and among the DOJ and certain of our affiliates (the "Plea Agreement"), could cause us to incur additional costs and liabilities. The continuing effects of the enhanced regulations may also decrease the demand for drilling services, negatively affect dayrates and increase out of service time, which could ultimately have a material adverse effect on our revenues and profitability.

§ Compliance with or breach of environmental laws can be costly, expose us to liability and could limit our operations.

Our business in the offshore drilling industry is affected by laws and regulations relating to the energy industry and the environment, including international conventions and treaties, and regional, national, state, and local laws and regulations. The offshore drilling industry depends on demand for services from the oil and gas exploration and production industry, and, accordingly, we are directly affected by the adoption of laws and regulations that, for economic, environmental or other policy reasons, curtail exploration and development drilling for oil and gas. Compliance with such laws, regulations and standards, where applicable, may require us to make significant capital expenditures, such as the installation of costly equipment or operational changes, and may affect the resale values or useful lives of our rigs.

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We may also incur additional costs in order to comply with other existing and future regulatory obligations, including, but not limited to, costs relating to air emissions, including greenhouse gases, the management of ballast waters, maintenance and inspection, development and implementation of emergency procedures and insurance coverage or other financial assurance of our ability to address pollution incidents. Offshore drilling in certain areas has been curtailed and, in certain cases, prohibited because of concerns over protection of the environment. These costs could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. 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.

To the extent new laws are enacted or other governmental actions are taken that prohibit or restrict offshore drilling or impose additional environmental protection requirements that result in increased costs to the oil and gas industry, in general, or the offshore drilling industry, in particular, our business or prospects could be materially adversely affected. The operation of our drilling rigs will require certain governmental approvals. These governmental approvals may involve public hearings and costly undertakings on our part. We may not obtain such approvals or such approvals may not be obtained in a timely manner. If we fail to timely secure the necessary approvals or permits, our customers may have the right to terminate or seek to renegotiate their drilling contracts to our detriment. The amendment or modification of existing laws and regulations or the adoption of new laws and regulations curtailing or further regulating exploratory or development drilling and production of oil and gas could have a material adverse effect on our business, operating results or financial condition. Compliance with any such new legislation or regulations could have an adverse effect on our statements of operations and cash flows.

As an operator of mobile offshore drilling units in some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or waste disposals related to those operations, and we may also be subject to significant fines in connection with spills. For example, an oil spill could result in significant liability, including fines, penalties and criminal liability and remediation costs for natural resource damages, as well as third-party damages, to the extent that the contractual indemnification provisions in our drilling contracts are not enforceable or otherwise sufficient, or if our customers are unwilling or unable to contractually indemnify us from these risks. Additionally, we may not be able to obtain such indemnities in our future drilling contracts, and our customers may not have the financial capability to fulfill their contractual obligations to us. Also, these indemnities may be held to be unenforceable in certain jurisdictions, as a result of public policy or for other reasons. For example, one of the courts in the litigation related to the Macondo well incident has refused to enforce aspects of our indemnity with respect to certain environmental related liabilities. Laws and regulations protecting the environment have become more stringent in recent years, and may in some cases impose strict liability, rendering a person liable for environmental damage without regard to negligence. These laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. The application of these requirements or the adoption of new requirements or measures could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. In addition, our Consent Decree, the EPA Agreement and probation arising out of our Plea Agreement add to these regulations, requirements and liabilities. Our guilty plea to negligently discharging oil into the U.S. Gulf of Mexico in connection with the Macondo well incident caused us to incur liabilities under the environmental laws relating to the Macondo well incident. We may be subject to additional liabilities and penalties.

§ The global nature of our operations involves additional risks.
We operate in various regions throughout the world, which may expose us to political and other uncertainties, including risks of:

§ terrorist acts, war, piracy and civil unrest;
§ seizure, expropriation or nationalization of our equipment;
§ expropriation or nationalization of our customers' property;

§ repudiation or nationalization of contracts;
§ imposition of trade or immigration barriers;
§ import export quotas;
§ wage and price controls;
§ changes in law and regulatory requirements, including changes in interpretation and enforcement;
§ involvement in judicial proceedings in unfavorable jurisdictions;
§ damage to our equipment or violence directed at our employees, including kidnappings;
§ complications associated with supplying, repairing and replacing equipment in remote locations;
§ the inability to move income or capital; and
§ currency exchange fluctuations and currency exchange restrictions, including exchange or similar controls that may limit our ability to convert local currency into U.S. dollars and transfer funds out of a local jurisdiction.

Our non U.S. contract drilling operations are subject to various laws and regulations in certain countries in which we operate, including laws and regulations relating to the import and export, equipment and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, taxation and social contributions of offshore earnings and earnings of expatriate personnel. We are also subject to the U.S. Treasury Department's Office of Foreign Assets Control ("OFAC") and other U.S. laws and regulations governing our international operations. In addition, various state and municipal governments, universities and other investors have proposed or adopted divestment and other initiatives regarding investments including, with respect to state governments, by state retirement systems in companies that do business with countries that have been designated as state sponsors of terrorism by the U.S. State

Department. Failure to comply with applicable laws and regulations, including those relating to sanctions and export restrictions, may subject us to criminal sanctions or civil remedies, including fines, denial of export privileges, injunctions or seizures of assets. Investors could view any potential violations of OFAC regulations negatively, which could adversely affect our reputation and the market for our shares.

Governments in some countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries, including local content requirements for participating in tenders for certain drilling contracts. Many governments favor or effectively require the awarding of drilling contracts to local contractors or require nonlocal contractors to employ citizens of, or purchase supplies from, a particular jurisdiction or require use of a local agent. In addition, government action, including initiatives by OPEC, may continue to cause oil or gas price volatility. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work by major oil companies and may continue to do so.

A substantial portion of our drilling contracts are partially payable in local currency. Those amounts may exceed our local currency needs, leading to the accumulation of excess local currency, which, in certain instances, may be subject to either temporary blocking or other difficulties converting to U.S. dollars, our functional currency, or to other currencies in which we operate. Excess amounts of local currency may be exposed to the risk of currency exchange losses.

The shipment of goods, services and technology across international borders subjects us to extensive trade laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the import and export of certain goods, services and technology and impose related import and export recordkeeping and reporting obligations. Governments also may impose economic sanctions against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities, and we are also subject to the U.S. anti boycott law.

The laws and regulations concerning import and export activity, recordkeeping and reporting, import and export control and economic sanctions are complex and constantly changing. These laws and regulations may be enacted, amended, enforced or interpreted in a manner materially impacting our operations. Ongoing economic challenges may increase some governments' efforts to enact, enforce, amend or interpret laws and regulations as a method to increase revenue. Shipments can be delayed and denied import or export for a variety of reasons, some of which are outside our control and some of which may result from failure to comply with existing legal and regulatory regimes. Shipping delays or denials could cause unscheduled operational downtime.

An inability to obtain visas and work permits for our employees on a timely basis could impact our operations and have an adverse effect on our business. Our ability to operate worldwide depends on our ability to obtain the necessary visas and work permits for our personnel to travel in and out of, and to work in, the jurisdictions in which we operate. Governmental actions in some of the jurisdictions in which we operate may make it difficult for us to move our personnel in and out of these jurisdictions by delaying or withholding the approval of these permits. If we are not able to obtain visas and work permits for the employees we need to operate our rigs on a timely basis, we might not be able to perform our obligations under our drilling contracts, which could allow our customers to cancel the contracts. If our customers cancel some of our drilling contracts, and we are unable to secure new drilling contracts on a timely basis and on substantially similar terms, it could adversely affect our consolidated statement of financial position, results of operations or cash flows.

§ Our business involves numerous operating hazards, and our insurance and indemnities from our customers may not be adequate to cover potential losses from our operations.

Our operations are subject to the usual hazards inherent in the drilling of oil and gas wells, such as, blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, craterings, fires, explosions and pollution. Contract drilling requires the use of heavy equipment and exposure to hazardous conditions, which may subject us to liability claims by employees, customers and other parties. These hazards can cause personal injury or loss of life, severe damage to or destruction of property and equipment, pollution or environmental damage, claims by third parties or customers and suspension of operations. Our offshore fleet is also subject to hazards inherent in marine operations, either while on site or during mobilization, such as capsizing, sinking, grounding, collision, piracy, damage from severe weather and marine life infestations.

The South China Sea, the Northwest Coast of Australia and the U.S. Gulf of Mexico area are subject to typhoons, hurricanes or other extreme weather conditions on a relatively frequent basis, and our drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury to or death of rig personnel. Some experts believe global climate change could increase the frequency and severity of these extreme weather conditions. Operations may also be suspended because of machinery breakdowns, abnormal drilling conditions, failure of subcontractors to perform or supply goods or services, or personnel shortages. We customarily provide contract indemnity to our customers for certain claims that could be asserted by us relating to damage to or loss of our equipment, including rigs, and claims that could be asserted by us or our employees relating to personal injury or loss of life.

Damage to the environment could also result from our operations, particularly through spillage of hydrocarbons, fuel, lubricants or other chemicals and substances used in drilling operations, or extensive uncontrolled fires. We may also be subject to property damage, environmental indemnity and other claims by oil and natural gas companies. Drilling involves certain risks associated with the loss of control

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of a well, such as blowout, cratering, the cost to regain control of or redrill the well and remediation of associated pollution. Our customers may be unable or unwilling to indemnify us against such risks. In addition, a court may decide that certain indemnities in our current or future drilling contracts are not enforceable. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy, and the enforceability of an indemnity as to other matters may be limited.

Our insurance policies and drilling contracts contain rights to indemnity that may not adequately cover our losses, and we do not have insurance coverage or rights to indemnity for all risks. We have two main types of insurance coverage: (1) hull and machinery coverage for physical damage to our property and equipment and (2) excess liability coverage, which generally covers offshore risks, such as personal injury, third party property claims, and third party non crew claims, including wreck removal and pollution. We generally have no hull and machinery insurance coverage for damages caused by named storms in the U.S. Gulf of Mexico. We maintain per occurrence deductibles that generally range up to $10 million for various third party liabilities and an additional aggregate annual deductible of $50 million, which is self-insured through our wholly owned captive insurance company. We also retain the risk for any liability in excess of our $750 million excess liability coverage. However, pollution and environmental risks generally are not completely insurable.

If a significant accident or other event occurs that is not fully covered by our insurance or by an enforceable or recoverable indemnity, the occurrence could adversely affect our consolidated statement of financial position, results of operations or cash flows. The amount of our insurance may also be less than the related impact on enterprise value after a loss. Our insurance coverage will not in all situations provide sufficient funds to protect us from all liabilities that could result from our drilling operations. Our coverage includes annual aggregate policy limits. As a result, we generally retain the risk for any losses in excess of these limits. We generally do not carry insurance for loss of revenue, and certain other claims may also not be reimbursed by insurance carriers. Any such lack of reimbursement may cause us to incur substantial costs. In addition, we could decide to retain more risk in the future, resulting in higher risk of losses, which could be material. Moreover, we may not be able to maintain adequate insurance in the future at rates that we consider reasonable or be able to obtain insurance against certain risks.

§ Recent developments in Swiss corporate governance may affect our ability to attract and retain top executives.
On January 1, 2014, subject to certain transitional provisions, the Swiss Federal Council Ordinance Against Excessive Compensation at Public Companies (the “Ordinance”) became effective. The Ordinance, among other things, (a) requires a binding shareholder “say on pay” vote with respect to the compensation of members of our executive management and board of directors (b) generally prohibits the making of severance, advance, transaction premiums and similar payments to members of our executive management and board of directors, and (c) requires the declassification of our board of directors and the amendment of our articles of association to specify various compensation related matters. At the 2014 annual general meeting, our shareholders approved amendments to our articles of association that implement the requirements of the Ordinance, and at each of our 2015 and 2016 annual general meetings our shareholders approved in a binding “say on pay” vote the compensation of members of our executive management and board of directors. At the 2017 annual general meeting, our shareholders will be required to approve the maximum aggregate compensation of (1) our board of directors for the period between the 2017 annual general meeting and the 2018 annual general meeting and (2) our executive management team for the year ending December 31, 2018. Our shareholders will be asked to approve such matters for successive one year periods at subsequent annual general meetings. The Ordinance further provides for criminal penalties against directors and members of executive management in case of noncompliance with certain of its requirements. The Ordinance may negatively affect our ability to attract and retain executive management and members of our board of directors.

§ Corporate restructuring activity, divestitures, acquisitions and other business combinations and reorganizations could adversely affect our ability to achieve our strategic goals.

We have undertaken and continue to seek appropriate opportunities for restructuring our organization, engaging in strategic acquisitions, divestitures and other business combinations in order to optimize our fleet and strengthen our competitiveness. We face risks arising from these activities, which could adversely affect our ability to achieve our strategic goals. For example:

§ We may be unable to realize the growth or investment opportunities, improvement of our financial position and other expected benefits by these activities in the expected time period or at all;
§ Transactions may not be completed as scheduled or at all due to legal or regulatory requirements, market conditions or contractual and other conditions to which such transactions are subject;
§ Unanticipated problems could also arise in the integration or separation processes, including unanticipated restructuring or separation expenses and liabilities, as well as delays or other difficulties in transitioning, coordinating, consolidating, replacing and integrating personnel, information and management systems, and customer products and services; and
§ The diversion of management and key employees' attention may detract from the our ability to increase revenues and minimize costs;
§ Certain transactions may result in other unanticipated adverse consequences.
§ Failure to recruit and retain key personnel could hurt our operations.

We depend on the continuing efforts of key members of our management, as well as other highly skilled personnel, to operate and provide technical services and support for our business worldwide. Historically, competition for the personnel required for drilling operations has intensified as the number of rigs activated, added to worldwide fleets or under construction increased, leading to shortages of qualified personnel in the industry and creating upward pressure on wages and higher turnover. We may experience a reduction in the experience

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level of our personnel as a result of any increased turnover and ongoing staff reduction initiatives, which could lead to higher downtime and more operating incidents, which in turn could decrease revenues and increase costs. If increased competition for qualified personnel were to intensify in the future we may experience increases in costs or limits on operations.

§ Significant part or equipment shortages, supplier capacity constraints, 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, parts, components and sub systems used in our operations exposes us to volatility in the quality, prices and availability of such items. Certain parts and equipment that we use in our operations may be available only from a small number of suppliers, manufacturers or service providers, or in some cases must be sourced through a single supplier, manufacturer or service provider. Recent industry developments have reduced the number of available suppliers. A disruption in the deliveries from such third party suppliers, manufacturers or service providers, capacity constraints, production disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment could adversely affect our ability to meet our commitments to customers, adversely impact our operations and revenues or increase our operating costs.

§ Our labor costs and the operating restrictions under which we operate could increase as a result of collective bargaining negotiations and changes in labor laws and regulations.

Approximately 28 percent of our total workforce, working primarily in Angola, Brazil, Norway and the U.K. are represented by, and some of our contracted labor work under, collective bargaining agreements, substantially all of which are subject to annual salary negotiation. These negotiations could result in higher personnel expenses, other increased costs or increased operational restrictions as the outcome of such negotiations apply to all offshore employees not just the union members. Legislation has been introduced in the U.S. Congress that could encourage additional unionization efforts in the U.S., as well as increase the chances that such efforts succeed. Additional unionization efforts, if successful, new collective bargaining agreements or work stoppages could materially increase our labor costs and operating restrictions.

§ Failure to comply with anti bribery statutes, such as the U.S. Foreign Corrupt Practices Act and the U.K. Bribery Act 2010, could result in fines, criminal penalties, drilling contract terminations and an adverse effect on our business.

The U.S. Foreign Corrupt Practices Act (“FCPA”), the U.K. Bribery Act 2010 (“Bribery Act”) and similar anti bribery laws in other jurisdictions, generally prohibit companies and their intermediaries from making improper payments for the purpose of obtaining or retaining business. We operate in many parts of the world that have experienced corruption to some degree and, in certain circumstances, strict compliance with anti bribery laws may conflict with local customs and practices. If we are found to be liable for violations under the FCPA, the Bribery Act or other similar laws, either due to our acts or omissions or due to the acts or omissions of others, including our partners in our various joint ventures, we could suffer from civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial condition and results of operations. In addition, investors could negatively view potential violations, inquiries or allegations of misconduct under the FCPA, the Bribery Act or similar laws, which could adversely affect our reputation and the market for our shares.

We could also face fines, sanctions and other penalties from authorities in the relevant jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of rigs or other assets. Additionally, we could also face other third party claims by agents, shareholders, debt holders, or other interest holders or constituents of our company. Further, disclosure of the subject matter of any investigation could adversely affect our reputation and our ability to obtain new business from potential customers or retain existing business from our current customers, to attract and retain employees and to access the capital markets. Our customers in relevant jurisdictions could seek to impose penalties or take other actions adverse to our interests, and we may be required to dedicate significant time and resources to investigate and resolve allegations of misconduct, regardless of the merit of such allegations.

§ Regulation of greenhouse gases and climate change could have a negative impact on our business.

Some scientific studies have suggested that emissions of certain gases, including greenhouse gases, carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of greenhouse gas emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide.

In the U.S., the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. In addition, a number of other federal, state and regional efforts have focused on tracking or reducing greenhouse gas emissions. Efforts have also been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of greenhouse gases. The Paris Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions.

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Because our business depends on the level of activity in the offshore oil and gas industry, existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and gas or limit drilling opportunities. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business.

§ We are subject to litigation that, if not resolved in our favor and not sufficiently insured against, could have a material adverse effect on us.

We are subject to a variety of disputes, investigations and litigation. Certain of our subsidiaries are named as defendants in numerous lawsuits alleging personal injury as a result of exposure to asbestos or toxic fumes or resulting from other occupational diseases, such as silicosis, and various other medical issues that can remain undiscovered for a considerable amount of time. Some of these subsidiaries that have been put on notice of potential liabilities have no assets. Further, our patent for dual activity technology has been successfully challenged in certain jurisdictions, and we have been accused of infringing other patents. Other subsidiaries are subject to litigation relating to environmental damage. We cannot predict the outcome of the cases involving those subsidiaries or the potential costs to resolve them. Insurance may not be applicable or sufficient in all cases, insurers may not remain solvent, policies may not be located, and liabilities associated with the Macondo well incident may exhaust some or all of the insurance available to cover certain claims. Suits against non asset owning subsidiaries have and may in the future give rise to alter ego or successor in interest claims against us and our asset owning subsidiaries to the extent a subsidiary is unable to pay a claim or insurance is not available or sufficient to cover the claims. We are subject to litigation with certain of our customers. We are also subject to a number of significant tax disputes. To the extent that one or more pending or future litigation matters is not resolved in our favor and is not covered by insurance, a material adverse effect on our financial results and condition could result.

§ Our information technology systems are subject to cybersecurity risks and threats.

We depend on digital technologies to conduct our offshore and onshore operations, to collect payments from customers and to pay vendors and employees. Threats to our information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. In addition, breaches to our systems could go unnoticed for some period of time. Risks associated with these threats include disruptions of certain systems on our rigs; other impairments of our ability to conduct our operations; loss of intellectual property, proprietary information or customer data; disruption of our customers' operations; loss or damage to our customer data delivery systems; and increased costs to prevent, respond to or mitigate cybersecurity events. If such a cyber incident were to occur, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

§ Acts of terrorism, piracy and political and social unrest could affect the markets for drilling services, which may have a material adverse effect on our results of operations.

Acts of terrorism and social unrest, brought about by world political events or otherwise, have caused instability in the world's financial and insurance markets in the past and may occur in the future. Such acts could be directed against companies such as ours. In addition, acts of terrorism, piracy and social unrest could lead to increased volatility in prices for crude oil and natural gas and could affect the markets for drilling services. Insurance premiums could increase and coverage may be unavailable in the future. Government regulations may effectively preclude us from engaging in business activities in certain countries. These regulations could be amended to cover countries where we currently operate or where we may wish to operate in the future. Our drilling contracts do not generally provide indemnification against loss of capital assets or loss of revenues resulting from acts of terrorism, piracy or political or social unrest. We have limited insurance for our assets providing coverage for physical damage losses resulting from risks, such as terrorist acts, piracy, vandalism, sabotage, civil unrest, expropriation and acts of war, and we do not carry insurance for loss of revenues resulting from such risks.

§ Public health threats could have a material adverse effect on our operations and our financial results.

Public health threats, such as Severe Acute Respiratory Syndrome, severe influenza and other highly communicable viruses or diseases, outbreaks of which have already occurred in various parts of the world in which we operate, could adversely impact our operations, the operations of our customers and the global economy, including the worldwide demand for oil and natural gas and the level of demand for our services. Quarantine of personnel or inability to access our offices or rigs could adversely affect our operations. Travel restrictions or operational problems in any part of the world in which we operate, or any reduction in the demand for drilling services caused by public health threats in the future, may materially impact operations and adversely affect our financial results.

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Other risks

§ We recently identified a material weakness in our internal control over financial reporting, and our business and stock price may be adversely affected if our internal control over financial reporting is not effective.

Under Section 404 of the Sarbanes Oxley Act of 2002 and rules promulgated by the SEC, we are required to conduct a comprehensive evaluation of our internal control over financial reporting. To complete this evaluation, we are required to document and test our internal control over financial reporting; management is required to assess and issue a report concerning our internal control over financial reporting; and our independent registered public accounting firm is required to attest to the effectiveness of our internal control over financial reporting. Our internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with policies or procedures. Because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and may not be prevented or detected timely. Even effective internal control over financial reporting can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements.

In the course of the external audit of the consolidated financial statements for the year ended December 31, 2016 we identified a material weakness in our controls over income tax accounting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. A more complete description of the recently identified errors and the resulting material weakness is included in "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 4—Correction of Errors in previously Reported Consolidated Financial Statements" and "Part II. Item 9A. Controls and Procedures" in this annual report on Form 10 K. Although we are evaluating certain measures in order to remediate this material weakness, we can provide no assurance that our remediation efforts will be effective or that additional material weaknesses in our internal control over financial reporting will not be identified in the future.

The existence of a material weakness could result in errors in our financial statements that could result in a restatement of financial statements, which could cause us to fail to meet our reporting obligations, lead to a loss of investor confidence and have a negative impact on the trading price of our common stock.

§ We have significant carrying amounts of long lived assets that are subject to impairment testing.

At December 31, 2016, the carrying amount of our property and equipment was $21.1 billion, representing 78 percent of our total assets. In accordance with our critical accounting policies, we review our property and equipment for impairment when events or changes in circumstances indicate that carrying amounts of our assets held and used may not be recoverable. In the year ended December 31, 2016, we recognized an aggregate loss of $52 million associated with the impairment of our deepwater floater asset group. In the year ended December 31, 2015, we recognized an aggregate loss of $1.2 billion associated with the impairment of our deepwater floater and midwater floater asset groups. Future expectations of lower dayrates or rig utilization rates or a significant change to the composition of one or more of our asset groups or to our contract drilling services reporting unit could result in the recognition of additional losses on impairment of our long lived asset groups if future cash flow expectations, based upon information available to management at the time of measurement, indicate that the carrying amount of our asset groups may be impaired.

§ A change in tax laws, treaties or regulations, or their interpretation, of any country in which we have operations, are incorporated or are resident could result in a higher tax rate on our worldwide earnings, which could result in a significant negative impact on our earnings and cash flows from operations.

We operate worldwide through our various subsidiaries. Consequently, we are subject to changes in applicable tax laws, treaties or regulations in the jurisdictions in which we operate, which could include laws or policies directed toward companies organized in jurisdictions with low tax rates. A material change in the tax laws, treaties or regulations, or their interpretation or application, of any country in which we have significant operations, or in which we are incorporated or resident, could result in a higher effective tax rate on our worldwide earnings and such change could be significant to our financial results.

In the U.S., major tax reform is under consideration. One proposal by the U.S. House of Representatives would impose a border adjustment on goods and services imported into the U.S. Although no bill or statutory language has to date been introduced, it is expected that such border adjustment would have the direct or indirect effect of taxing goods and services sourced from outside the U.S. Such a border adjustment, if implemented, could result in a higher effective tax rate on our worldwide earnings and have a material adverse effect on our consolidated statements of financial position, results of operations or cash flows. Further, tax legislative proposals intending to eliminate some perceived tax advantages of companies that have legal domiciles outside the U.S., but have certain U.S. connections, have repeatedly been introduced in the U.S. Congress. Recent examples include, but are not limited to, legislative proposals that would broaden the circumstances in which a non U.S. company would be considered a U.S. resident, including the use of "management and control" provisions to determine corporate residency, and proposals that could override certain tax treaties and limit treaty benefits on certain payments by U.S. subsidiaries to non U.S. affiliates. Any material change in tax laws or policies, or their interpretation, resulting from such

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legislative proposals or inquiries could result in a higher effective tax rate on our worldwide earnings and such change could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

In a referendum held on February 12, 2017, Swiss voters rejected a corporate tax legislative proposal that would have abolished certain cantonal tax privileges as well as implement other significant changes to existing tax laws and practices starting in 2019. These legislative proposals were in response to certain guidance from and demands by the European Union and the Organization for Economic Co operation and Development (the "OECD"). Switzerland must now give consideration to a revised corporate tax reform proposal. Switzerland's implementation of any material change in tax laws or policies or its adoption of new interpretations of existing tax laws and rulings could result in a higher effective tax rate on our worldwide earnings and such change could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Similarly, in October 2015, the OECD issued its action plan of tax reform measures that called for member states to take action to prevent "base erosion and profit shifting". Some of these measures impact transfer pricing, requirements to qualify for tax treaty benefits, and the definition of permanent establishments depending on each jurisdiction's adoption and interpretation of such proposals. The European Union issued its Anti Tax Avoidance Directive in 2016 that required its member states to adopt specific tax reform measures by 2019. Any material change in tax laws or policies, or their interpretation, resulting from such legislative proposals or inquiries could result in a higher effective tax rate on our worldwide earnings and such change could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other tax jurisdictions in which we operate may consider implementing similar legislation. The implementation of such legislation, any other material changes in tax laws or policies or the adoption of new interpretations of existing tax laws and rulings could result in a higher effective tax rate on our worldwide earnings and any such change could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

§ A loss of a major tax dispute or a successful tax challenge to our operating structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries could result in a higher tax rate on our worldwide earnings, which could result in a significant negative impact on our earnings and cash flows from operations.

We are a Swiss corporation that operates through our various subsidiaries in a number of countries throughout the world. Consequently, we are subject to tax laws, treaties and regulations in and between the countries in which we operate. Our income taxes are based upon the applicable tax laws and tax rates in effect in the countries in which we operate and earn income as well as upon our operating structures in these countries.

Our income tax returns are subject to review and examination. We do not recognize the benefit of income tax positions we believe are more likely than not to be disallowed upon challenge by a tax authority. If any tax authority successfully challenges our operational structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries; or if the terms of certain income tax treaties are interpreted in a manner that is adverse to our structure; or if we lose a material tax dispute in any country, particularly in the U.S., Norway, India or Brazil, our effective tax rate on our worldwide earnings could increase substantially and our earnings and cash flows from operations could be materially adversely affected. For example, we cannot be certain that the U.S. Internal Revenue Service ("IRS") will not successfully contend that we or any of our key subsidiaries were or are engaged in a trade or business in the U.S. or, when applicable, that we or any of our key subsidiaries maintained or maintain a permanent establishment in the U.S., since, among other things, such determination involves considerable uncertainty. If we or any of our key subsidiaries were considered to have been engaged in a trade or business in the U.S., when applicable, through a permanent establishment, we could be subject to U.S. corporate income and additional branch profits taxes on the portion of our earnings effectively connected to such U.S. business during the period in which this was considered to have occurred, in which case our effective tax rate on worldwide earnings for that period could increase substantially, and our earnings and cash flows from operations for that period could be adversely affected.

§ U.S. tax authorities could treat us as a passive foreign investment company, which would have adverse U.S. federal income tax consequences to U.S. holders.

A foreign corporation will be treated as a passive foreign investment company ("PFIC") for U.S. federal income tax purposes 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 produce or are held for the production of those types of passive income. For purposes of these tests, passive income includes dividends, interest and gains from the sale or exchange of investment property and certain rents and royalties, but does not include income derived from the performance of services.

We believe that we have not been and will not be a PFIC with respect to any taxable year. Our income from offshore contract drilling services should be treated as services income for purposes of determining whether we are a PFIC. Accordingly, we believe that our income from our offshore contract drilling services should not constitute "passive income," and the assets that we own and operate in connection with the production of that income should not constitute passive assets.

There is significant legal authority supporting this position, including statutory provisions, legislative history, case law and IRS pronouncements concerning the characterization, for other tax purposes, of income derived from services where a substantial component of such income is attributable to the value of the property or equipment used in connection with providing such services. It should be noted, however, that a prior case and an IRS pronouncement which relies on the case characterize income from time chartering of vessels as rental income rather than services income for other tax purposes. However, the IRS subsequently has formally announced that it does not agree with the decision in that case. Moreover, we believe that the terms of the time charters in the recent case differ in material respects from the terms of our drilling contracts with customers. No assurance can be given that the IRS or a court will accept our position, and there is a risk that the IRS or a court could determine that we are a PFIC.

If we were to be treated as a PFIC for any taxable year, our U.S. shareholders would face adverse U.S. tax consequences. Under the PFIC rules, unless a shareholder makes certain elections available under the Internal Revenue Code of 1986, as amended, and such elections could themselves have adverse consequences for such shareholder, such shareholder generally would be liable to pay U.S. federal income tax at the highest applicable income tax rates on ordinary income upon the receipt of excess distributions, as defined for U.S. tax purposes, and upon any gain from the disposition of our shares, plus interest on such amounts, as if such excess distribution or gain had been recognized ratably over the shareholder's holding period of our shares. In addition, under applicable statutory provisions, the preferential tax rate on "qualified dividend income," which applies to dividends paid to non corporate shareholders does not apply to dividends paid by a foreign corporation if the foreign corporation is a PFIC for the taxable year in which the dividend is paid or the preceding taxable year.

§ We may be limited in our use of net operating losses and tax credits.

Our ability to benefit from our deferred tax assets depends on us having sufficient future earnings to utilize our net operating loss and tax credit carryforwards before they expire. We have established a valuation allowance against the future tax benefit for a number of our U.S. and non U.S. net operating losses and tax credit carryforwards, and we could be required to record an additional valuation allowance against other U.S. or non U.S. deferred tax assets if market conditions change materially and, as a result, our future earnings are, or are projected to be, significantly less than we currently estimate. Our net operating loss and tax credit carryforwards are subject to review and potential disallowance upon audit by the tax authorities of the jurisdictions where these tax attributes are incurred.

§ Our status as a Swiss corporation may limit our flexibility with respect to certain aspects of capital management and may cause us to be unable to make distributions or repurchase shares without subjecting our shareholders to Swiss withholding tax.

Under Swiss law, our shareholders may approve an authorized share capital that allows the board of directors to issue new shares without additional shareholder approval. As a matter of Swiss law, authorized share capital is limited to a maximum of 50 percent of a company's registered share capital and is subject to re approval by shareholders every two years. At our 2016 annual general meeting, our shareholders approved an authorized share capital, which will expire on May 12, 2018. Our current authorized share capital is limited to approximately six percent of our registered share capital. Additionally, subject to specified exceptions, Swiss law grants preemptive rights to existing shareholders to subscribe for new issuances of shares. Further, Swiss law does not provide as much flexibility in the various terms that can attach to different classes of shares as the laws of some other jurisdictions. Swiss law also reserves for shareholder approval certain corporate actions over which a board of directors would have authority in some other jurisdictions. For example, dividends must be approved by shareholders. These Swiss law requirements relating to our capital management may limit our flexibility, and situations may arise where greater flexibility would have provided substantial benefits to our shareholders.

Distributions to shareholders in the form of a par value reduction and dividend distributions out of qualifying additional paid in capital are not currently subject to the 35 percent Swiss federal withholding tax. However, the Swiss withholding tax rules could also be changed in the future, and any such change may adversely affect us or our shareholders. In addition, over the long term, the amount of par value available for us to use for par value reductions or the amount of qualifying additional paid in capital available for us to pay out as distributions is limited. If we are unable to make a distribution through a reduction in par value, or out of qualifying additional paid in capital as shown on Transocean Ltd.'s standalone Swiss statutory financial statements, we may not be able to make distributions without subjecting our shareholders to Swiss withholding taxes.

Under present Swiss tax law, repurchases of shares for the purposes of capital reduction are treated as a partial liquidation subject to a 35 percent Swiss withholding tax on the repurchase price less the par value, and since January 1, 2011, to the extent attributable to qualifying additional paid in capital, if any. At our 2009 annual general meeting, our shareholders approved the repurchase of up to CHF 3.5 billion of our shares for cancellation under the share repurchase program. We may repurchase shares under the share repurchase program using a procedure pursuant to which we can repurchase shares under the share repurchase program via a "virtual second trading line" from market players, in particular, banks and institutional investors, who are generally entitled to receive a full refund of the Swiss withholding tax. Our ability to use the "virtual second trading line" is limited to the share repurchase program currently approved by our shareholders, and any use of the "virtual second trading line" with respect to future share repurchase programs will require the approval of the competent Swiss tax authorities. We may not be able to repurchase as many shares as we would like to repurchase for purposes of capital reduction on the "virtual second trading line" without subjecting the selling shareholders to Swiss withholding taxes.

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§ As a Swiss corporation, we are subject to Swiss legal provisions that may limit our flexibility to swiftly implement certain initiatives or strategies.

We are required, from time to time, to evaluate the carrying amount of our investments in affiliates, as presented on our Swiss standalone balance sheet. If we determine that the carrying amount of any such investment exceeds its fair value, we may conclude that such investment is impaired. The recognized loss associated with such a non-cash impairment could result in our net assets no longer covering our statutory share capital and statutory capital reserves. Under Swiss law, if our net assets cover less than 50 percent of our statutory share capital and statutory capital reserves, the board of directors must in these circumstances convene a general meeting of shareholders and propose measures to remedy such a capital loss. The appropriate measures depend on the relevant circumstances and the magnitude of the recognized loss and may include seeking shareholder approval for offsetting the aggregate loss, or a portion thereof, with our statutory capital reserves including qualifying additional paid-in capital otherwise available for distributions to shareholders or raising new equity. Depending on the circumstances, we may also need to use qualifying additional paid in capital available for distributions in order to reduce our accumulated net loss and such use might reduce our ability to make distributions without subjecting our shareholders to Swiss withholding tax. These Swiss law requirements could limit our flexibility to swiftly implement certain initiatives or strategies.

§ We are subject to anti takeover provisions.

Our articles of association and Swiss law contain provisions that could prevent or delay an acquisition of the company by means of a tender offer, a proxy contest or otherwise. These provisions may also adversely affect prevailing market prices for our shares. These provisions, among other things:

§ provide that the board of directors is authorized, subject to obtaining shareholder approval every two years, at any time during a maximum two year period, which under the current authorized share capital of the Company will expire on May 12, 2018, to issue a specified number of shares, which under the current authorized share capital of the Company is approximately six percent of the share capital registered in the commercial register, and to limit or withdraw the preemptive rights of existing shareholders in various circumstances;

§ provide for a conditional share capital that authorizes the issuance of additional shares up to a maximum amount of approximately 36 percent of the share capital currently registered in the commercial register without obtaining additional shareholder approval through: (1) the exercise of conversion, exchange, option, warrant or similar rights for the subscription of shares granted in connection with bonds, options, warrants or other securities newly or already issued in national or international capital markets or new or already existing contractual obligations by or of any of our subsidiaries; or (2) in connection with the issuance of shares, options or other share based awards;

§ provide that any shareholder who wishes to propose any business or to nominate a person or persons for election as director at any annual meeting may only do so if advance notice is given to the company;

§ provide that directors can be removed from office only by the affirmative vote of the holders of at least 66 2/3 percent of the shares entitled to vote;

§ provide that a merger or demerger transaction requires the affirmative vote of the holders of at least 66 2/3 percent of the shares represented at the meeting and provide for the possibility of a so called "cashout" or "squeezeout" merger if the acquirer controls 90 percent of the outstanding shares entitled to vote at the meeting;

§ provide that any action required or permitted to be taken by the holders of shares must be taken at a duly called annual or extraordinary general meeting of shareholders;

§ limit the ability of our shareholders to amend or repeal some provisions of our articles of association; and

§ limit transactions between us and an "interested shareholder," which is generally defined as a shareholder that, together with its affiliates and associates, beneficially, directly or indirectly, owns 15 percent or more of our shares entitled to vote at a general meeting.

§ The results of the U.K.'s referendum on withdrawal from the European Union may have a negative effect on global economic conditions, financial markets and our business.

In June 2016, a majority of voters in the U.K. elected to withdraw from the European Union in a national referendum. The referendum was advisory, and the terms of any withdrawal are subject to a negotiation period that could last at least two years after the government of the U.K. formally initiates a withdrawal process. Nevertheless, the referendum has created significant uncertainty about the future relationship between the U.K. and the European Union, including with respect to the laws and regulations that will apply as the U.K. determines which European Union derived laws to replace or replicate in the event of a withdrawal. The referendum has also given rise to calls for the governments of other European Union member states to consider withdrawal. These developments, or the perception that any of them could occur, have had and may continue to have a material adverse effect on global economic conditions and the stability of global financial markets, and may significantly reduce global market liquidity and restrict the ability of key market participants to operate in certain financial markets. Any of these factors could depress economic activity and restrict our access to capital, which could have a material adverse effect on our business and on our consolidated statement of financial position, results of operations or cash flows.

Item 1B.Unresolved Staff Comments

None.

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Item 2.Properties

The description of our property included under “Item 1. Business” is incorporated by reference herein. We maintain offices, land bases and other facilities worldwide, including the following:

§ principal executive offices in Vernier, Switzerland; and
§ corporate offices in Zug, Switzerland; Houston, Texas; and Cayman Islands.

Our remaining offices and bases are located in various countries in North America, South America, Europe, Africa, India and the Far East. We lease most of these facilities.

Item 3.Legal Proceedings

We have certain actions, claims and other matters pending as discussed and reported in “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies” and “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contingencies and Uncertainties—” in this annual report on Form 10 K for the year ended December 31, 2016. We are also involved in various tax matters as described in “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 7—Income Taxes” and in “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contingencies and Uncertainties—Tax matters” in this annual report on Form 10 K for the year ended December 31, 2016. All such actions, claims, tax and other matters are incorporated herein by reference.

As of December 31, 2016, we were also involved in a number of other lawsuits, claims and disputes, which have arisen in the ordinary course of our business and for which we do not expect the liability, if any, to have a material adverse effect on our current consolidated statement of financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the matters referred to above or of any such other pending or threatened litigation or legal proceedings. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or claim or dispute will prove correct and the eventual outcome of these matters could materially differ from management’s current estimates.

In addition to the legal proceedings described above, we may from time to time identify other matters that we monitor through our compliance program and in response to events arising generally within our industry and in the markets where we do business. For example, in the year ended December 31, 2015, we began investigating statements made by a former employee of Petróleo Brasileiro S.A. (“Petrobras”) related to the award to us of a drilling services contract in Brazil. These statements were made in connection with an ongoing criminal investigation by the Brazilian authorities into Petrobras and certain other companies and individuals. We have completed our internal investigation, and we have not identified any wrongdoing by any of our employees or agents in connection with our business. We have voluntarily met with governmental authorities in the U.S. to discuss the statements made by the former Petrobras employee and our internal investigation as well as our findings. We will continue to investigate these types of allegations and cooperate with governmental authorities. Through the process of monitoring and proactive investigation, we strive to ensure no violation of our policies, Code of Integrity or law has, or will, occur; however, there can be no assurance as to the outcome of these matters.

Item 4.Mine Safety Disclosures

Not applicable.

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Executive Officers of the Registrant

We have included the following information, presented as of February 16, 2017, on our executive officers for purposes of U.S. securities laws in Part I of this report in reliance on General Instruction G(3) to Form 10 K. The board of directors elects the officers of the Company, generally on an annual basis. There is no family relationship between any of our executive officers.

Officer	Office	Age as of February 16, 2017
Jeremy D. Thigpen (a)	President and Chief Executive Officer	42
Terry B. Bonno	Senior Vice President, Industry and Community Relations	59
Howard E. Davis	Executive Vice President, Chief Administrative Officer and Chief Information Officer	58
Brady K. Long	Senior Vice President and General Counsel	44
Mark L. Mey (a)	Executive Vice President, Chief Financial Officer	53
John B. Stobart (a)	Executive Vice President, Chief Operating Officer	62
David Tonnel	Senior Vice President, Supply Chain and Corporate Controller	47

(a) Member of our executive management team for purposes of Swiss law.

Jeremy D. Thigpen is President and Chief Executive Officer and a member of the Company's board of directors. Before joining the Company in April 2015, Mr. Thigpen served as Senior Vice President and Chief Financial Officer at National Oilwell Varco, Inc. from December 2012 to April 2015. At National Oilwell Varco, Inc., Mr. Thigpen also served as President, Downhole and Pumping Solutions from August 2007 to December 2012, as President of the Downhole Tools Group from May 2003 to August 2007 and as manager of the Downhole Tools Group from April 2002 to May 2003. From 2000 to 2002, Mr. Thigpen served as the Director of Business Development and Special Assistant to the Chairman for National Oilwell Varco, Inc. Mr. Thigpen earned a Bachelor of Arts degree in Economics and Managerial Studies from Rice University in 1997, and he completed the Program for Management Development at Harvard Business School in 2001.

Terry B. Bonno is Senior Vice President, Industry and Community Relations, of the Company. Before being named to her current position in February 2017, Ms. Bonno served as Senior Vice President, Marketing from August 2011 to February 2017 and Vice President, Marketing from April 2008 to August 2011, and as Director, Marketing North and South America Unit, responsible for the U.S. Gulf of Mexico, Canada, Trinidad and Brazil, from March 2005 to April 2008. Ms. Bonno has served as a non-executive director of NOW Inc. since May 2014. Ms. Bonno started with the Company in 2001 and has held various management positions in marketing, accounting and corporate planning. Ms. Bonno earned a Bachelor's degree in Business Administration - Accounting from Stephen F. Austin State University in 1980, and she is a certified public accountant.

Howard E. Davis is Executive Vice President, Chief Administrative Officer and Chief Information Officer of the Company. Before joining the Company in August 2015, Mr. Davis served as Senior Vice President, Chief Administrative Officer and Chief Information Officer of National Oilwell Varco, Inc. from March 2005 to April 2015 and as Vice President, Chief Administrative Officer and Chief Information Officer from August 2002 to March 2005. Mr. Davis earned a Bachelor's degree from University of Kentucky in 1980, and he completed the Advanced Management Program at Harvard Business School in 2005.

Brady K. Long is Senior Vice President and General Counsel of the Company. Before joining the Company in November 2015, Mr. Long served since 2011 as Vice President - General Counsel and Secretary of Ensco plc, which acquired Pride International, Inc. where he had served as Vice President, General Counsel and Secretary since August 2009. Mr. Long joined Pride International, Inc. in June 2005 as Assistant General Counsel and served as Chief Compliance Officer from June 2006 to February 2009. He was director of Transocean Partners LLC from May 2016 until December 2016. Mr. Long previously practiced corporate and securities law with the law firm of Bracewell LLP. He earned a Bachelor of Arts degree from Brigham Young University in 1996 and a Juris Doctorate degree from the University of Texas School of Law in 1999.

Mark L. Mey is Executive Vice President, Chief Financial Officer of the Company. Before joining the Company in May 2015, Mr. Mey served as Executive Vice President of Atwood Oceanics, Inc. from January 2015 to May 2015, prior to which he served as Senior Vice President and Chief Financial Officer from August 2010. Mr. Mey was director of Transocean Partners LLC from June 2015 until December 2016. He served as Director, Senior Vice President and Chief Financial Officer of Scorpion Offshore Ltd. from August 2005 to July 2010. Prior to 2005, Mr. Mey held various senior financial and other roles in the drilling and financial services industries, including 12 years with Noble Corporation. He earned an Advanced Diploma in Accounting and a Bachelor of Commerce degree from the University of Port Elizabeth in South Africa in 1985, and he is a chartered accountant. Additionally, Mr. Mey completed the Harvard Business School Executive Advanced Management Program in 1998.

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John B. Stobart is Executive Vice President, Chief Operating Officer of the Company. Before joining the Company in October 2012, Mr. Stobart served as Vice President, Global Drilling for BHP Billiton Petroleum from July 2011 to October 2012. At BHP Billiton, he also served as Worldwide Drilling Manager for BHP Billiton in Australia, the U.K. and the U.S. from January 1995 to June 2011 and as Senior Drilling Engineer, Senior Drilling Supervisor, Drilling Superintendent and Drilling Manager in the United Arab Emirates, Oman, India, Burma, Malaysia, Vietnam and Australia from June 1988 to December 1994. Mr. Stobart served as Engineering Manager at Husky/Bow Valley from November 1984 to May 1988, and he worked in engineering roles at Dome Petroleum/Canadian Marine Drilling from May 1980 to October 1984. He began his career working on land rigs in Canada and the High Arctic in June 1971. Mr. Stobart earned a Bachelor of Science degree in Mechanical Engineering from the University of Calgary in 1980, and he completed the London Business School Accelerated Development Program in 2000.

David Tonnel is Senior Vice President, Supply Chain and Corporate Controller of the Company. Before being named to his current position in October 2015, he served as Senior Vice President, Finance and Controller from March 2012 to October 2015 and as Senior Vice President of the Europe and Africa Unit from June 2009 to March 2012. Mr. Tonnel served as Vice President of Global Supply Chain from November 2008 to June 2009, as Vice President of Integration and Process Improvement from November 2007 to November 2008, and as Vice President and Controller from February 2005 to November 2007. Prior to February 2005, he served in various financial roles, including Assistant Controller; Finance Manager, Asia Australia Region; and Controller, Nigeria. Mr. Tonnel joined the Company in 1996 after working for Ernst & Young in France as Senior Auditor. Mr. Tonnel earned a Master of Science degree in Management from Ecole des Hautes Etudes Commerciales in Paris, France in 1991.

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PART II

Item 5.Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Market for Shares of Our Common Equity

Our shares are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "RIG". The following table presents the intraday high and low per share sales prices as reported on the NYSE for the periods indicated.

	NYSE Stock Price			
	2016		2015	
	High	Low	High	Low
First quarter	$ 13.48	$ 7.67	$ 20.65	$ 13.28
Second quarter	12.05	8.34	21.90	14.44
Third quarter	13.03	8.68	16.20	11.26
Fourth quarter	16.66	9.10	17.19	11.95

Our shares were previously listed on the SIX Swiss Exchange ("SIX") under the symbol "RIGN". Effective March 31, 2016, at our request, our shares were delisted from the SIX.

On February 28, 2017, the last reported sales price of our shares on the NYSE was $13.82 per share. On February 28, 2017, there were 6,278 holders of record of our shares and 389,597,755 shares outstanding.

Shareholder Matters

Shareholder distributions

In May 2015, at our annual general meeting, our shareholders approved the distribution of qualifying additional paid in capital in the form of a United States ("U.S.") dollar denominated dividend of $0.60 per outstanding share, payable in four quarterly installments of $0.15 per outstanding share, subject to certain limitations. On June 17 and September 23, 2015, we paid the first two installments in the aggregate amount of $109 million to shareholders of record as of May 29 and August 25, 2015. On October 29, 2015, at our extraordinary general meeting, shareholders approved the cancellation of the third and fourth installments of the distribution.

In May 2014, at our annual general meeting, our shareholders approved the distribution of qualifying additional paid in capital in the form of a U.S. dollar denominated dividend of $3.00 per outstanding share, payable in four quarterly installments of $0.75 per outstanding share, subject to certain limitations. On June 18, September 17 and December 17, 2014, we paid the first three installments in the aggregate amount of $816 million to shareholders of record as of May 30, August 22 and November 14, 2014, respectively. On March 18, 2015, we paid the final installment in the aggregate amount of $272 million to shareholders of record as of February 20, 2015.

We did not pay the distribution of qualifying additional paid in capital with respect to our shares held in treasury or held by our subsidiary. Any future declaration and payment of any cash distributions will (1) depend on our results of operations, financial condition, cash requirements and other relevant factors, (2) be subject to shareholder approval, (3) be subject to restrictions contained in our credit facilities and other debt covenants, (4) be affected by our plans regarding share repurchases or noncash shareholder distributions and (5) be subject to restrictions imposed by Swiss law, including the requirement that sufficient distributable profits from the previous year or freely distributable reserves must exist.

Swiss tax consequences to our shareholders

Overview—The tax consequences discussed below are not a complete analysis or listing of all the possible tax consequences that may be relevant to our shareholders. Shareholders should consult their own tax advisors in respect of the tax consequences related to receipt, ownership, purchase or sale or other disposition of our shares and the procedures for claiming a refund of withholding tax.

Swiss income tax on dividends and similar distributions—A non Swiss holder will not be subject to Swiss income taxes on dividend income and similar distributions in respect of our shares, unless the shares are attributable to a permanent establishment or a fixed place of business maintained in Switzerland by such non Swiss holder. However, dividends and similar distributions are subject to Swiss withholding tax, subject to certain exceptions. See "—Swiss withholding tax on dividends and similar distributions to shareholders."

Swiss wealth tax—A non Swiss holder will not be subject to Swiss wealth taxes unless the holder's shares are attributable to a permanent establishment or a fixed place of business maintained in Switzerland by such non Swiss holder.

Swiss capital gains tax upon disposal of shares—A non Swiss holder will not be subject to Swiss income taxes for capital gains unless the holder's shares are attributable to a permanent establishment or a fixed place of business maintained in Switzerland by such non Swiss holder. In such case, the non Swiss holder is required to recognize capital gains or losses on the sale of such shares, which will be subject to cantonal, communal and federal income tax.

Swiss withholding tax on dividends and similar distributions to shareholders—A Swiss withholding tax of 35 percent is due on dividends and similar distributions to our shareholders from us, regardless of the place of residency of the shareholder, subject to the exceptions discussed under "—Exemption" below. We will be required to withhold at such rate and remit on a net basis any payments made to a holder of our shares and pay such withheld amounts to the Swiss federal tax authorities.

Exemption—Distributions to shareholders in the form of a par value reduction or out of qualifying additional paid in capital for Swiss statutory purposes are exempt from Swiss withholding tax. On December 31, 2016, the aggregate amount of par value of our outstanding shares was CHF 39 million, equivalent to approximately $39 million, and the aggregate amount of qualifying additional paid in capital of our outstanding shares was CHF 11.4 billion, equivalent to approximately $11.2 billion. Consequently, we expect that a substantial amount of any potential future distributions may be exempt from Swiss withholding tax.

Refund available to Swiss holders—A Swiss tax resident, corporate or individual, can recover the withholding tax in full if such resident is the beneficial owner of our shares at the time the dividend or other distribution becomes due and provided that such resident reports the gross distribution received on such resident's income tax return, or in the case of an entity, includes the taxable income in such resident's income statement.

Refund available to non Swiss holders—If the shareholder that receives a distribution from us is not a Swiss tax resident, does not hold our shares in connection with a permanent establishment or a fixed place of business maintained in Switzerland, and resides in a country that has concluded a treaty for the avoidance of double taxation with Switzerland for which the conditions for the application and protection of and by the treaty are met, then the shareholder may be entitled to a full or partial refund of the withholding tax described above. Switzerland has entered into bilateral treaties for the avoidance of double taxation with respect to income taxes with numerous countries, including the U.S., whereby under certain circumstances all or part of the withholding tax may be refunded. The procedures for claiming treaty refunds, and the time frame required for obtaining a refund, may differ from country to country.

Refund available to U.S. residents—The Swiss U.S. tax treaty provides that U.S. residents eligible for benefits under the treaty can seek a refund of the Swiss withholding tax on dividends for the portion exceeding 15 percent, leading to a refund of 20 percent, or a 100 percent refund in the case of qualified pension funds. As a general rule, the refund will be granted under the treaty if the U.S. resident can show evidence of the following: (a) beneficial ownership, (b) U.S. residency and (c) meeting the U.S. Swiss tax treaty's limitation on benefits requirements.

The claim for refund must be filed with the Swiss federal tax authorities (Eigerstrasse 65, 3003 Bern, Switzerland), not later than December 31 of the third year following the year in which the dividend payments became due. The relevant Swiss tax form is Form 82C for companies, 82E for other entities and 82I for individuals. These forms can be obtained from any Swiss Consulate General in the U.S. or from the Swiss federal tax authorities at the above address or can be downloaded from the webpage of the Swiss federal tax administration. Each form must be completed in triplicate, with each copy duly completed and signed before a notary public in the U.S. Evidence that the withholding tax was withheld at the source must also be included.

Stamp duties in relation to the transfer of shares—The purchase or sale of our shares may be subject to Swiss federal stamp taxes on the transfer of securities irrespective of the place of residency of the purchaser or seller if the transaction takes place through or with a Swiss bank or other Swiss securities dealer, as those terms are defined in the Swiss Federal Stamp Tax Act and no exemption applies in the specific case. If a purchase or sale is not entered into through or with a Swiss bank or other Swiss securities dealer, then no stamp tax will be due. The applicable stamp tax rate is 0.075 percent for each of the two parties to a transaction and is calculated based on the purchase price or sale proceeds. If the transaction does not involve cash consideration, the transfer stamp duty is computed on the basis of the market value of the consideration.

Share repurchases

Repurchases of shares for the purposes of capital reduction are treated as a partial liquidation subject to the 35 percent Swiss withholding tax. However, for shares repurchased for capital reduction, the portion of the repurchase price attributable to the par value of the shares repurchased will not be subject to the Swiss withholding tax. Since January 1, 2011, the portion of the repurchase price that is according to Swiss tax law and practice attributable to the qualifying additional paid in capital for Swiss statutory reporting purposes of the shares repurchased will also not be subject to the Swiss withholding tax. We would be required to withhold at such rate the tax from the difference between the repurchase price and the related amount of par value and, since January 2011, the related amount of qualifying additional paid in capital, if any. We would be required to remit on a net basis the purchase price with the Swiss withholding tax deducted to a holder of our shares and pay the withholding tax to the Swiss federal tax authorities.

If we repurchase shares, we expect to use an alternative procedure pursuant to which we repurchase our shares via a "virtual second trading line" from market players, such as banks and institutional investors, who are generally entitled to receive a full refund of the Swiss withholding tax. Currently, our ability to use the “virtual second trading line” will be limited to the share repurchase program currently approved by our shareholders, and any use of the “virtual second trading line” with respect to future share repurchase programs will require approval of the competent Swiss tax and other authorities. We may not be able to repurchase as many shares as we would like to repurchase

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for purposes of capital reduction on the "virtual second trading line" without subjecting the selling shareholders to Swiss withholding taxes. The repurchase of shares for purposes other than for cancellation, such as to retain as treasury shares for use in connection with stock incentive plans, convertible debt or other instruments within certain periods, will generally not be subject to Swiss withholding tax.

Under Swiss corporate law, the right of a company and its subsidiaries to repurchase and hold its own shares is limited. A company may repurchase its shares to the extent it has freely distributable reserves as shown on its Swiss statutory balance sheet in the amount of the purchase price and the aggregate par value of all shares held by the company as treasury shares does not exceed 10 percent of the company's share capital recorded in the Swiss Commercial Register, whereby for purposes of determining whether the 10 percent threshold has been reached, shares repurchased under a share repurchase program for cancellation purposes authorized by the company's shareholders are disregarded. As of February 28, 2017, Transocean Inc., our wholly owned subsidiary, held as treasury shares approximately one percent of our issued shares. Our board of directors could, to the extent freely distributable reserves are available, authorize the repurchase of additional shares for purposes other than cancellation, such as to retain treasury shares for use in satisfying our obligations in connection with incentive plans or other rights to acquire our shares. Based on the current amount of shares held as treasury shares, approximately nine percent of our issued shares could be repurchased for purposes of retention as additional treasury shares. Although our board of directors has not approved such a share repurchase program for the purpose of retaining repurchased shares as treasury shares, if it did so, any such shares repurchased would be in addition to any shares repurchased under the currently approved program.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (a)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (b)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) (b)
October 2016	9,917	$ 9	—	$ 3.180
November 2016	—	—	—	3.180
December 2016	—	—	—	3.180
Total	9,917	$ 9	—	$ 3.180

(a) Total number of shares purchased in the fourth quarter of 2016 consists of 9,917 shares withheld by us through a broker arrangement and limited to statutory tax in satisfaction of withholding taxes due upon the vesting of restricted share units granted to our employees under our long term incentive plan.

(b) In May 2009, at our annual general meeting, our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, equivalent to approximately $3.4 billion. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. Through December 31, 2016, we repurchased a total of 2,863,267 of our shares under our share repurchase program at a total cost of $240 million, equivalent to an average cost of $83.74 per share. On October 29, 2015, at our extraordinary general meeting, shareholders approved the cancellation of all shares that were repurchased to date under our share repurchase program. The cancellation of our shares held in treasury became effective as of January 7, 2016 upon registration of the cancellation in the commercial register. We may decide, based upon our ongoing capital requirements, our program of distributions to our shareholders, the price of our shares, regulatory and tax considerations, cash flow generation, the amount and duration of our contract backlog, general market conditions, debt rating considerations and other factors, that we should retain cash, reduce debt, make capital investments or acquisitions or otherwise use cash for general corporate purposes, and consequently, repurchase fewer or no additional shares under this program. Decisions regarding the amount, if any, and timing of any share repurchases would be made from time to time based upon these factors. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Sources and uses of liquidity.”

Item 6.Selected Financial Data

The selected financial data as of December 31, 2016 and 2015 and for each of the three years in the period ended December 31, 2016 have been derived from the audited consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.” The selected financial data as of December 31, 2014, 2013 and 2012, and for each of the two years in the period ended December 31, 2013 have been derived from our accounting records. The following data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the audited consolidated financial statements and the notes thereto included under “Item 8. Financial Statements and Supplementary Data.”

The following data contain certain corrections of errors identified in previously reported amounts. For the years ended December 31, 2015, 2014 and 2013, the effect of the corrections on net income was a net favorable adjustment of $71 million, $66 million and $30 million, respectively. For the year ended December31, 2012, the effect of the corrections was a net unfavorable adjustment of $67 million to net income and a net favorable adjustment of $35 million to beginning retained earnings. See “Item 8. Financial Statements

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and Supplementary Data—Notes to Consolidated Financial Statements—Note 4—Correction of Errors in Previously Reported Consolidated Financial Statements."

	Years ended December 31,				
	2016 (a)	2015	2014 (b)	2013	2012
	(In millions, except per share data)				
Statement of operations data					
Operating revenues	$ 4,161	$ 7,386	$ 9,185	$ 9,246	$ 8,942
Operating income (loss)	1,132	1,365	(1,347)	2,203	1,588
Income (loss) from continuing operations	827	895	(1,880)	1,428	765
Net income (loss)	827	897	(1,900)	1,437	(278)
Net income (loss) attributable to controlling interest	778	865	(1,839)	1,434	(291)
Per share earnings (loss) from continuing operations					
Basic	$ 2.08	$ 2.36	$ (5.02)	$ 3.92	$ 2.11
Diluted	$ 2.08	$ 2.36	$ (5.02)	$ 3.92	$ 2.11
Balance sheet data (at end of period)					
Total assets	$ 26,889	$ 26,431	$ 28,676	$ 32,759	$ 34,534
Debt due within one year	724	1,093	1,032	323	1,365
Long-term debt	7,740	7,397	9,019	10,329	11,035
Total equity	15,805	15,000	14,104	16,719	15,803
Other financial data					
Cash provided by operating activities	$ 1,911	$ 3,445	$ 2,220	$ 1,918	$ 2,708
Cash used in investing activities	(1,313)	(1,932)	(1,828)	(1,658)	(389)
Cash provided by (used in) financing activities	115	(1,809)	(1,000)	(2,151)	(1,202)
Capital expenditures	1,344	2,001	2,165	2,238	1,303
Distributions of qualifying additional paid-in capital	—	381	1,018	606	276
Per share distributions of qualifying additional paid-in capital	$ —	$ 1.05	$ 2.81	$ 1.68	$ 0.79

(a)In December 2016, as contemplated by the Agreement and Plan of Merger (the "Merger Agreement"), Transocean Partners LLC ("Transocean Partners") and one of our subsidiaries completed the merger, with Transocean Partners became a wholly owned indirect subsidiary of Transocean Ltd. Each Transocean Partners common unit that was issued and outstanding immediately prior to the closing, other than units held by Transocean and its subsidiaries, was converted into the right to receive 1.20 of our shares. To complete the merger, we issued 23.8 million shares from conditional capital.

(b)In August 2014, we completed an initial public offering to sell a noncontrolling interest in Transocean Partners, which was formed on February 6, 2014, by Transocean Partners Holdings Limited, a Cayman Islands company and our wholly owned subsidiary.

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

The following information should be read in conjunction with the information contained in "Part I. Item 1. Business," "Part I. Item 1A. Risk Factors" and the audited consolidated financial statements and the notes thereto included under "Item 8. Financial Statements and Supplementary Data" elsewhere in this annual report.

Business

Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean," the "Company," "we," "us" or "our") is a leading international provider of offshore contract drilling services for oil and gas wells. As of February 28, 2017, we owned or had partial ownership interests in and operated 56 mobile offshore drilling units, including 30 ultra deepwater floaters, seven harsh environment floaters, three deepwater floaters, six midwater floaters, and 10 high specification jackups. At February 16, 2017, we also had four ultra deepwater drillships and five high specification jackups under construction or under contract to be constructed.

We provide contract drilling services in a single, global operating segment, which involves contracting our mobile offshore drilling fleet, related equipment and work crews primarily on a dayrate basis to drill oil and gas wells. We specialize in technically demanding regions of the offshore drilling business with a particular focus on deepwater and harsh environment drilling services. We believe our drilling fleet is one of the most versatile fleets in the world, consisting of floaters and high specification jackups used in support of offshore drilling activities and offshore support services on a worldwide basis.

Our contract drilling services operations are geographically dispersed in oil and gas exploration and development areas throughout the world. Although rigs can be moved from one region to another, the cost of moving rigs and the availability of rig moving vessels may cause the supply and demand balance to fluctuate somewhat between regions. Still, significant variations between regions do not tend to persist long term because of rig mobility. Our fleet operates in a single, global market for the provision of contract drilling services. The location of our rigs and the allocation of resources to operate, build or upgrade our rigs are determined by the activities and needs of our customers.

Significant Events

Transocean Partners—On December 9, 2016, Transocean Partners completed a merger with one of our subsidiaries as contemplated under the Agreement and Plan of Merger (the "Merger Agreement"), dated July 31, 2016 and as amended on November 21, 2016. Following the completion of the merger, Transocean Partners became a wholly owned indirect subsidiary of Transocean Ltd. Each Transocean Partners common unit that was issued and outstanding immediately prior to the closing, other than the units held by Transocean and its subsidiaries, was converted into the right to receive 1.20 of our shares. To complete the merger, we issued 23.8 million shares from conditional capital.

Debt issuances—On July 21, 2016, we completed an offering of an aggregate principal amount of $1.25 billion of 9.00% senior unsecured notes due July 15, 2023 (the "9.00% Senior Notes"), and we received aggregate cash proceeds of $1.21 billion, net of initial discount and costs payable by us. On October 19, 2016, we completed an offering of an aggregate principal amount of $600 million of 7.75% senior secured notes due October 15, 2024 (the "7.75% Senior Secured Notes"), and we received aggregate cash proceeds of $583 million, net of initial discount and costs payable by us. On December 8, 2016, we completed an offering of an aggregate principal amount of $625 million of 6.25% senior secured notes due December 1, 2024 (the "6.25% Senior Secured Notes"), and we received aggregate cash proceeds of $609 million, net of initial discount and costs payable by us. See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Debt tender offer—On August 1, 2016, we completed a tender offer (the “Tender Offer”) to purchase for cash up to $1.0 billion aggregate principal amount of certain of our outstanding senior notes (collectively, the “Tendered Notes”). In connection with the Tender Offer, we received valid tenders from holders of an aggregate principal amount of $981 million of the Tendered Notes, and we made an aggregate cash payment of $876 million to settle the Tendered Notes. In the year ended December 31, 2016, as a result of the retirement of the Tendered Notes, we recognized an aggregate gain of $104 million associated with the retirement of debt. See “—Liquidity and Capital Resources—Sources and uses of liquidity.”

Debt repurchases—During the year ended December 31, 2016, we completed transactions to repurchase in the open market an aggregate principal amount of $399 million of our debt securities for an aggregate cash payment of $354 million. As a result, we recognized an aggregate gain of $44 million associated with the retirement of debt. See “—Liquidity and Capital Resources—Sources and uses of liquidity”.

Fleet expansion—During the year ended December 31, 2016, we completed construction of and placed into service the ultra deepwater floaters Deepwater Thalassa, Deepwater Proteus and Deepwater Conqueror. See “—Operating Results” and “—Liquidity and Capital Resources—Drilling fleet.”

Drilling contract terminations—As a result of recent market conditions, we have observed an unprecedented level of early drilling contract terminations in the contract drilling industry. In the year ended December 31, 2016, we recognized revenues of $471 million and received aggregate cash proceeds of $453 million associated with early terminated or cancelled drilling contracts. See "—Outlook," "—Operating Results" and "—Liquidity and Capital Resources—Sources and uses of cash."

Dispositions—During the year ended December 31, 2016, we completed the sale for scrap value of three deepwater floaters and eight midwater floaters, along with related equipment, for which we received net cash proceeds of $22 million, and recognized an aggregate net gain of $13 million. See "—Liquidity and Capital Resources—Drilling fleet."

Impairments of long lived assets—In the year ended December 31, 2016, as a result of impairment testing, we determined that our deepwater asset group was impaired, and we recognized a loss of $52 million, which had no tax effect, associated with the impairment of these held and used assets. In the year ended December 31, 2016, we committed to a plan to sell for scrap value three deepwater floaters and eight midwater floaters, along with related equipment. As a result, we recognized an aggregate loss of $41 million ($39 million, net of tax), associated with the impairment of these held for sale assets. See "—Operating Results", "—Liquidity and Capital Resources—Drilling fleet" and Notes to Consolidated Financial Statements—Note 6—Impairments.

Markets for our shares—Our shares are listed on the New York Stock Exchange under the ticker symbol "RIG" and were previously listed on the SIX Swiss Exchange ("SIX") under the symbol "RIGN". Effective March 31, 2016, at our request, our shares were delisted from the SIX.

Par value reduction—On October 29, 2015, at our extraordinary general meeting, our shareholders approved the reduction of the par value of each of our shares to CHF 0.10 from the original par value of CHF 15.00. The reduction of the par value became effective as of January 7, 2016 upon registration in the commercial register.

Outlook

Drilling market—Our long term view of the offshore drilling market remains positive, particularly for high specification assets. However, although commodity pricing has improved over the past few months, our customers continue to focus on cost reduction, debt reduction and maintaining their current level of dividend payments. As such, we expect them to continue to limit spending on offshore exploration and development opportunities in 2017. The risks of drilling project delays, contract renegotiations and contract terminations remain in the near term. Additionally, as a result of current market conditions, we have observed an increased number of requests for nonstandard contractual terms, including extended payment terms. During the year ended December 31, 2016, our customers early terminated or cancelled drilling contracts for Deepwater Asgard, Deepwater Champion, Deepwater Millennium, Discoverer Deep Seas, Discoverer India, GSF Constellation II, GSF Development Driller I and Transocean John Shaw. During the year ended December 31, 2015, our customers early terminated or cancelled contracts for Discoverer Americas, Polar Pioneer, Sedco 714, Sedco Energy and Transocean Spitsbergen.

As expected, few new contracts were awarded during the year ended December 31, 2016, resulting in falling rig utilization rates negatively impacting dayrates. Over time, we believe the current oil supply and demand imbalance will narrow. As spare oil capacity diminishes, we expect upward pressure on commodity pricing with subsequent increased demand for drilling rigs.

Fleet status—We refer to the availability of our rigs in terms of the uncommitted fleet rate. The uncommitted fleet rate is defined as the number of uncommitted days divided by the total number of rig calendar days in the measurement period, expressed as a percentage. An uncommitted day is defined as a calendar day during which a rig is idle or stacked, is not contracted to a customer and is not committed to a shipyard. The uncommitted fleet rates exclude the effect of priced options.

As of February 9, 2017, uncommitted fleet rates for each of the five years in the period ending December 31, 2021 were as follows:

	2017	2018	2019	2020	2021
Uncommitted fleet rate					
Ultra-deepwater floaters	64%	75%	80 %	85 %	85 %
Harsh environment floaters	71%	86%	93 %	100%	100%
Deepwater floaters	33%	44%	100%	100%	100%
Midwater floaters	86%	92%	100%	100%	100%
High-specification jackups	79%	93%	100%	100%	100%

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Performance and Other Key Indicators

Contract backlog—Contract backlog is defined as the maximum contractual operating dayrate multiplied by the number of days remaining in the firm contract period, excluding revenues for mobilization, demobilization and contract preparation or other incentive provisions, which are not expected to be significant to our contract drilling revenues. Average contractual dayrate relative to our contract backlog is defined as the maximum contractual operating dayrate to be earned per operating day in the measurement period. An operating day is defined as a day for which a rig is contracted to earn a dayrate during the firm contract period after commencement of operations.

The contract backlog represents the maximum contract drilling revenues that can be earned considering the contractual operating dayrate in effect during the firm contract period and represents the basis for the maximum revenues in our revenue efficiency measurement. To determine maximum revenues for purposes of calculating revenue efficiency, however, we include the revenues earned for mobilization, demobilization and contract preparation, other incentive provisions or cost escalation provisions which are excluded from the amounts presented for contract backlog. The contract backlog for our fleet was as follows:

	February 9, 2017	October 24, 2016	February 11, 2016
Contract backlog	(In millions)		
Ultra-deepwater floaters	$ 10,070	$ 10,740	$ 13,539
Harsh environment floaters	623	746	920
Deepwater floaters	259	299	320
Midwater floaters	127	150	261
High-specification jackups	172	246	467
Total contract backlog	$ 11,251	$ 12,181	$ 15,507

Our contract backlog includes only firm commitments, which are represented by signed drilling contracts or, in some cases, by other definitive agreements awaiting contract execution. Our contract backlog includes amounts associated with our newbuild units that are currently under construction. The contractual operating dayrate may be higher than the actual dayrate we ultimately receive or an alternative contractual dayrate, such as a waiting on weather rate, repair rate, standby rate or force majeure rate, may apply under certain circumstances. The contractual operating dayrate may also be higher than the actual dayrate we ultimately receive because of a number of factors, 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.

In December 2016, a subsidiary of Chevron Corporation (together with its affiliates, “Chevron”) issued a notice of early termination of the drilling contract for Deepwater Asgard, effective February 3, 2017. In January 2017, Chevron adjusted the termination date to be January 13, 2017. As a result of the termination, our contract backlog for ultra deepwater floaters reflects a reduction of approximately $110 million to remove the backlog related to this contract.

At February 9, 2017, the contract backlog and average contractual dayrates for our fleet were as follows:

		For the years ending December 31,				
	Total	2017	2018	2019	2020	Thereafter

Contract backlog	(In millions, except average dayrates)					
Ultra-deepwater floaters	$ 10,070	$ 1,638	$ 1,478	$ 1,240	$ 993	$ 4,721
Harsh environment floaters	623	360	220	43	—	—
Deepwater floaters	259	134	125	—	—	—
Midwater floaters	127	58	54	15	—	—
High-specification jackups	172	124	48	—	—	—
Total contract backlog	$ 11,251	$ 2,314	$ 1,925	$ 1,298	$ 993	$ 4,721
Average-contractual dayrates						
Ultra-deepwater floaters	$ 513,000	$ 496,000	$ 522,000	$ 520,000	$ 523,000	$ 512,000
Harsh environment floaters	$ 288,000	$ 285,000	$ 289,000	$ 305,000	$ —	$ —
Deepwater floaters	$ 206,000	$ 206,000	$ 206,000	$ —	$ —	$ —
Midwater floaters	$ 99,000	$ 99,000	$ 99,000	$ 101,000	$ —	$ —
High-specification jackups	$ 143,000	$ 144,000	$ 140,000	$ —	$ —	$ —
Total fleet average	$ 440,000	$ 347,000	$ 379,000	$ 485,000	$ 523,000	$ 512,000

The actual amounts of revenues earned and the actual periods during which revenues are earned will differ from the amounts and periods shown in the tables above due to various factors, including shipyard and maintenance projects, unplanned downtime and other factors that result in lower applicable dayrates than the full contractual operating dayrate. Additional factors that could affect the amount and timing of actual revenue to be recognized include customer liquidity issues and contract terminations, which are available to our customers under certain circumstances.

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Average daily revenue—Average daily revenue is defined as contract drilling revenues earned per operating day. An operating day is defined as a calendar day during which a rig is contracted to earn a dayrate during the firm contract period after commencement of operations. The average daily revenue for our fleet was as follows:

	Years ended December 31, 2016	2015	2014
Average daily revenue			
Ultra-deepwater floaters	$ 492,100	$ 513,900	$ 538,400
Harsh environment floaters	$ 329,100	$ 542,600	$ 470,500
Deepwater floaters	$ 253,900	$ 354,400	$ 378,300
Midwater floaters	$ 274,100	$ 349,200	$ 347,200
High-specification jackups	$ 143,800	$ 172,900	$ 168,500
Total fleet average daily revenue	$ 353,500	$ 400,500	$ 408,200

Our average daily revenue fluctuates relative to market conditions and our revenue efficiency. The average daily revenue may also be affected by revenues for lump sum bonuses or demobilization fees received from our customers. Our total fleet average daily revenue is also affected by the mix of rig classes being operated, as deepwater floaters, midwater floaters and high specification jackups are typically contracted at lower dayrates compared to ultra deepwater floaters and harsh environment floaters. We include newbuilds in the calculation when the rigs commence operations upon acceptance by the customer. We remove rigs from the calculation upon disposal, classification as held for sale or classification as discontinued operations.

Revenue efficiency—Revenue efficiency is defined as actual contract drilling revenues for the measurement period divided by the maximum revenue calculated for the measurement period, expressed as a percentage. Maximum revenue is defined as the greatest amount of contract drilling revenues the drilling unit could earn for the measurement period, excluding amounts related to incentive provisions. The revenue efficiency rates for our fleet were as follows:

	Years ended December 31, 2016	2015	2014
Revenue efficiency			
Ultra-deepwater floaters	98 %	95 %	94 %
Harsh environment floaters	98 %	98 %	96 %
Deepwater floaters	96 %	97 %	96 %
Midwater floaters	99 %	95 %	93 %
High-specification jackups	98 %	99 %	97 %
Total fleet average revenue efficiency	98 %	96 %	95 %

Our revenue efficiency rate varies due to revenues earned under alternative contractual dayrates, such as a waiting on weather rate, repair rate, standby rate, force majeure rate or zero rate, that may apply under certain circumstances. We include newbuilds in the calculation when the rigs commence operations upon acceptance by the customer. We exclude rigs that are not operating under contract, such as those that are stacked.

Rig utilization—Rig utilization is defined as the total number of operating days divided by the total number of rig calendar days in the measurement period, expressed as a percentage. The rig utilization rates for our fleet were as follows:

	Years ended December 31,					
	2016		2015		2014	
Rig utilization						
Ultra-deepwater floaters	45	%	65	%	82	%
Harsh environment floaters	57	%	64	%	91	%
Deepwater floaters	54	%	73	%	62	%
Midwater floaters	42	%	77	%	64	%
High-specification jackups	55	%	83	%	93	%
Total fleet average rig utilization	48	%	71	%	76	%

Our rig utilization rate declines as a result of idle and stacked rigs and during shipyard and mobilization periods to the extent these rigs are not earning revenues. We include newbuilds in the calculation when the rigs commence operations upon acceptance by the customer. We remove rigs from the calculation upon disposal, classification as held for sale or classification as discontinued operations. Accordingly, our rig utilization can increase when idle or stacked units are removed from our drilling fleet.

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Operating Results

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

The following analysis of our operating results contains corrections of errors identified in previously reported amounts (see Notes to Consolidated Financial Statements—Note 4—Correction of Errors in Previously Reported Consolidated Financial Statements). See "—Performance and Other Key Indicators" for definitions of operating days, average daily revenue, revenue efficiency and rig utilization.

	Years ended December 31, 2016	2015	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	10,443	16,948	(6,505)	(38) %
Average daily revenue	$ 353,500	$ 400,500	$ (47,000)	(12) %
Revenue efficiency	98 %	96 %		
Rig utilization	48 %	71 %		
Contract drilling revenues	$ 3,705	$ 6,802	$ (3,097)	(46) %
Other revenues	456	584	(128)	(22) %
	4,161	7,386	(3,225)	(44) %
Operating and maintenance expense	(1,875)	(2,955)	1,080	37 %
Depreciation expense	(893)	(963)	70	7 %
General and administrative expense	(172)	(192)	20	10 %
Loss on impairment	(93)	(1,875)	1,782	95 %
Gain (loss) on disposal of assets, net	4	(36)	40	nm
Operating income	1,132	1,365	(233)	(17) %
Other income (expense), net				
Interest income	20	22	(2)	(9) %
Interest expense, net of amounts capitalized	(409)	(432)	23	5 %
Gain on retirement of debt	148	23	125	nm
Other, net	43	37	6	16 %
Income from continuing operations before income tax expense	934	1,015	(81)	(8) %
Income tax expense	(107)	(120)	13	11 %
Income from continuing operations	$ 827	$ 895	$ (68)	(8) %

"nm" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to the following: (a) approximately $2.2 billion of decreased revenues resulting from a greater number of rigs idle or stacked, (b) approximately $860 million of decreased revenues resulting from rigs sold or classified as held for sale and (c) approximately $365 million of decreased revenues resulting from lower dayrates. These decreases were partially offset by (a) approximately $270 million of increased revenues associated with our newbuild ultra deepwater drillships that commenced operations in the year ended

December 31, 2016 and (b) approximately $70 million of increased revenues resulting from improved revenue efficiency.

Other revenues decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to approximately $91 million of decreased revenues for reimbursable items and approximately $37 million of decreased revenues resulting from drilling contracts early terminated or cancelled by our customers.

Costs and expenses—Excluding the income effect of $30 million and $788 million of cost reimbursements from settlements, recoveries from insurance and net adjustments to contingent liabilities associated with the Macondo well incident in the years ended 2016 and 2015, respectively, operating and maintenance expense decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015, by approximately $1.8 billion. This decrease was primarily due to the following: (a) approximately $1.04 billion of decreased costs and expenses resulting from a greater number of rigs idle or stacked, (b) approximately $355 million of decreased costs and expenses resulting from rigs sold or classified as held for sale, (c) approximately $315 million of decreased costs and expenses primarily related to optimized maintenance and shipyard expenses and reduced personnel costs associated with our active fleet and (d) approximately $195 million of decreased costs and expenses resulting from reduced onshore costs. These decreases were partially offset by approximately $75 million of increased costs and expenses associated with our newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2016.

Depreciation expense decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to the following: (a) approximately $87 million of decreased depreciation primarily resulting from the impairment of our deepwater floater and midwater floater asset groups in the prior year and (b) approximately $40 million of decreased depreciation resulting from rigs sold or classified as held for sale, partially offset by (c) approximately $66 million of increased depreciation associated with our newbuild ultra deepwater drillships and other property and equipment placed into service in the year ended December 31, 2016.

General and administrative expense decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to the following: (a) approximately $22 million of reduced personnel costs, (b) approximately $8 million of reduced rental expenses, partially offset by (c) approximately $9 million of increased professional fees.

Loss on impairment and disposals—In the year ended December 31, 2016, we recognized a loss on impairment related to the following: (a) a loss of $52 million associated with the impairment of our deepwater floater asset group and (b) a loss of $41 million associated with the impairment of certain assets classified as held for sale. In the year ended December 31, 2015, we recognized a loss on impairment related to the following: (a) an aggregate loss of $700 million associated with the impairment of certain assets classified as held for sale, (b) a loss of $668 million associated with the impairment of our midwater floater asset group and (c) a loss of $507 million associated with the impairment of our deepwater floater asset group.

In the year ended December 31, 2016, we recognized an aggregate net loss associated with the disposal of three deepwater floaters and eight midwater floaters, along with related equipment, and other assets. In the year ended December 31, 2015, we recognized an aggregate net loss associated with the disposal of two ultra deepwater floaters, six deepwater floaters and nine midwater floaters, along with related equipment, and other assets.

Other income and expense—Interest expense, net of amounts capitalized, decreased in the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to the following: (a) approximately $98 million of decreased interest expense resulting from our debt repurchases and redemptions and (b) approximately $36 million of increased interest capitalized resulting from our newbuild construction program, partially offset by (c) approximately $64 million of increased interest resulting from new debt issued in the year ended December 31, 2016 and (d) approximately $37 million of increased interest expense resulting from downgrades to the credit rating for our senior unsecured long-term debt.

In the year ended December 31, 2016, we recognized net gains due to the following: (a) an aggregate gain of $104 million resulting from the completion of our tender offer of certain of our debt securities and (b) an aggregate net gain of $44 million resulting from our repurchases of $399 million aggregate principal amount of our debt securities. In the year ended December 31, 2015, we recognized a net gain due to the following: (a) an aggregate net gain of $33 million resulting from our repurchases of $503 million aggregate principal amount of our debt securities partially offset by (b) an aggregate loss of $10 million resulting from the redemption of $893 million aggregate principal amount of the 4.95% senior notes due November 2015 (the “4.95% Senior Notes”).

Income tax expense—We operate internationally and provide for income taxes based on the tax laws and rates in the countries in which we operate and earn income. For the years ended December 31, 2016 and 2015, our effective tax rate, excluding discrete items, was 18.5 percent and 14.4 percent, respectively, based on income from continuing operations before income tax expense, after excluding certain items, such as losses on impairment, and gains and losses on certain asset disposals. Our effective tax rate increased in the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to (a) changes in the relative blend of income from operations in certain jurisdictions and (b) valuation allowances on deferred tax assets for losses not expected to be realized. We consider the tax effect, if any, of the excluded items as well as settlements of prior year tax estimates to be discrete period tax expenses or benefits. In the years ended December 31, 2016 and 2015, the effect of the various discrete period tax items was a net tax benefit of $50 million and $75 million, respectively. For the years ended December 31, 2016 and 2015, these discrete tax items, coupled with the excluded income and expense items noted above, resulted in an effective tax rate of 11.5 percent and 11.9 percent, respectively, based on income from continuing operations before income tax expense.

The relationship between our provision for or benefit from income taxes and our income 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 versus income before taxes, (c) rig movements between taxing jurisdictions and (d) our rig operating structures. Generally, our marginal tax rate is lower than our effective tax rate. Consequently, our income tax expense does not change proportionally with our income before income taxes. Significant decreases in our income before income taxes typically lead to higher effective tax rates, while significant increases in income before income taxes can lead to lower effective tax rates, subject to the other factors impacting income tax expense noted above. With respect to the effective tax rate calculation for the year ended December 31, 2016, a significant portion of our income tax expense was generated in countries in which income taxes are imposed on gross revenues, with the most significant of these countries being Angola. Conversely, the countries in which we incurred the most significant income taxes during this period that were based on income before income tax include Norway, Switzerland, the U.K. and the U.S.

Our rig operating structures further complicate our tax calculations, especially in instances where we have more than one operating structure for the particular taxing jurisdiction and, thus, more than one method of calculating taxes depending on the operating structure utilized by the rig under the contract. For example, two rigs operating in the same country could generate significantly different provisions for income taxes if they are owned by two different subsidiaries that are subject to differing tax laws and regulations in the respective country of incorporation.

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

The following analysis of our operating results contains certain corrections of errors identified in previously reported amounts (see Notes to Consolidated Financial Statements—Note 4—Correction of Errors in Previously Reported Consolidated Financial Statements). See "—Performance and Other Key Indicators" for definitions of operating days, average daily revenue, revenue efficiency and rig utilization.

	Years ended December 31, 2015	2014	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	16,948	21,893	(4,945)	(23) %
Average daily revenue	$ 400,500	$ 408,200	$ (7,700)	(2) %
Revenue efficiency	96 %	95 %		
Rig utilization	71 %	76 %		
Contract drilling revenues	$ 6,802	$ 8,963	$ (2,161)	(24) %
Other revenues	584	222	362	nm
	7,386	9,185	(1,799)	(20) %
Operating and maintenance expense	(2,955)	(5,100)	2,145	42 %
Depreciation expense	(963)	(1,129)	166	15 %
General and administrative expense	(192)	(234)	42	18 %
Loss on impairment	(1,875)	(4,043)	2,168	54 %
Loss on disposal of assets, net	(36)	(26)	(10)	(38) %
Operating income (loss)	1,365	(1,347)	2,712	nm
Other income (expense), net				
Interest income	22	20	2	10 %
Interest expense, net of amounts capitalized	(432)	(483)	51	11 %
Gain (loss) on retirement of debt	23	(13)	36	nm
Other, net	37	35	2	6 %
Income (loss) from continuing operations before income tax expense	1,015	(1,788)	2,803	nm
Income tax expense	(120)	(92)	(28)	(30) %
Income (loss) from continuing operations	$ 895	$ (1,880)	$ 2,775	nm

"nm" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to the following: (a) approximately $1.7 billion of decreased revenues resulting from a greater number of rigs idle or stacked, (b) approximately $945 million of decreased revenues resulting from rigs sold or classified as held for sale and (c) approximately $120 million of decreased revenues resulting from lower dayrates. These decreases were partially offset by the following: (a) approximately $280 million of increased revenues associated with our two newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2014, (b) approximately $240 million of increased revenues resulting from fewer shipyard and mobilization days for the active fleet, (c) approximately $105 million of increased revenues resulting from improved revenue efficiency and (d) approximately $90 million of increased revenues resulting from demobilization fees.

Other revenues increased for the year ended December 31, 2015 compared to the year ended December 31, 2014, primarily due to $433 million of revenues resulting from drilling contracts early terminated or cancelled by our customers.

Costs and expenses—Excluding the favorable effect of $788 million resulting from cost reimbursements from settlements, recoveries from insurance and net adjustments to contingent liabilities associated with the Macondo well incident in the year ended December 31, 2015, operating and maintenance expense decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to the following: (a) approximately $545 million of decreased costs and expenses resulting from rigs sold or classified as held for sale, (b) approximately $395 million of decreased costs and expenses resulting from cost reductions for our idle or stacked rigs, (c) approximately $345 million of decreased costs and expenses resulting fewer shipyard and mobilization costs and reduced personnel expenses associated with our active fleet and (d) approximately $135 million of decreased costs and expenses resulting from reduced onshore costs. These decreases were partially offset by approximately $70 million of increased costs and expenses associated with our two newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2014.

Depreciation expense decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to the following: (a) approximately $198 million of decreased depreciation resulting from rigs sold or classified as held for sale and (b) approximately $94 million of decreased depreciation resulting from the impairment of our deepwater floater and midwater floater asset groups. These decreases were partially offset by the following: (a) approximately $51 million of increased depreciation resulting from the reduction of the salvage values for certain drilling units and (b) approximately $30 million of increased depreciation resulting from our

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two newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2014 and (c) approximately $45 million of increased depreciation resulting from our completion of other construction projects.

Loss on impairment—In the year ended December 31, 2015, we recognized a loss on impairment related to the following: (a) an aggregate loss of $700 million associated with the impairment of certain assets classified as held for sale, (b) a loss of $668 million associated with the impairment of our midwater floater asset group and (c) a loss of $507 million associated with the impairment of our deepwater floater asset group. In the year ended December 31, 2014, we recognized a loss on impairment related to the following: (a) a loss of $3.0 billion associated with the full impairment of the carrying amount of our goodwill, (b) a loss of $788 million associated with the impairment of our deepwater floater asset group and (c) an aggregate loss of $268 million associated with the impairment of certain assets classified as held for sale.

Income tax expense—We operate internationally and provide for income taxes based on the tax laws and rates in the countries in which we operate and earn income. For the years ended December 31, 2015 and 2014, our effective tax rate, excluding discrete items, was 14.4 percent and 16.4 percent, respectively, based on income from continuing operations before income tax expense, after excluding certain items, such as losses on impairment, and gains and losses on certain asset disposals. We consider the tax effect, if any, of the excluded items as well as settlements of prior year tax liabilities and changes in prior year tax estimates to be discrete period tax expenses or benefits. In the years ended December 31, 2015 and 2014, the effect of the various discrete period tax items was a net tax benefit of $75 million and $143 million, respectively. For the years ended December 31, 2015 and 2014, these discrete tax items, coupled with the excluded income and expense items noted above, resulted in an effective tax rate of 11.9 percent and (5.0) percent, respectively, based on income from continuing operations before income taxes.

The relationship between our provision for or benefit from income taxes and our income 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 versus income before taxes, (c) rig movements between taxing jurisdictions and (d) our rig operating structures. Generally, our marginal tax rate is lower than our effective tax rate. Consequently, our income tax expense does not change proportionally with our income before income taxes. Significant decreases in our income before income taxes typically lead to higher effective tax rates, while significant increases in income before income taxes can lead to lower effective tax rates, subject to the other factors impacting income tax expense noted above. With respect to the effective tax rate calculation for the year ended December 31, 2015, a significant portion of our income tax expense was generated in countries in which income taxes are imposed on gross revenues, with the most significant of these countries being Angola, India, Nigeria, Indonesia and the Republic of Congo. Conversely, the countries in which we incurred the most significant income taxes during this period that were based on income before income tax include Norway, the U.K., Switzerland, Brazil and the U.S.

Our rig operating structures further complicate our tax calculations, especially in instances where we have more than one operating structure for the particular taxing jurisdiction and, thus, more than one method of calculating taxes depending on the operating structure utilized by the rig under the contract. For example, two rigs operating in the same country could generate significantly different provisions for income taxes if they are owned by two different subsidiaries that are subject to differing tax laws and regulations in the respective country of incorporation.

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Liquidity and Capital Resources

Sources and uses of cash

At December 31, 2016, we had $3.1 billion in cash and cash equivalents. In the year ended December 31, 2016, our primary sources of cash were our cash flows from operating activities, including cash proceeds from customers that executed early terminations or cancellations of drilling contracts; net proceeds from the issuance of debt and net proceeds from restricted cash investments. Our primary uses of cash were capital expenditures, primarily associated with our newbuild construction projects, repayment of debt at scheduled maturities, settlement of the Tendered Notes, debt repurchased in the open market and payment of scheduled installments for our Macondo well incident settlement obligations.

	Years ended December 31,		
	2016	2015	Change
	(In millions)		
Cash flows from operating activities			
Net income	$ 827	$ 897	$ (70)
Depreciation	893	963	(70)
Loss on impairment	93	1,875	(1,782)
Gain on retirement of debt	(148)	(23)	(125)
Deferred income tax expense (benefit)	68	(134)	202
Other non-cash items, net	52	173	(121)
Changes in deferred revenues and costs, net	291	89	202
Changes in other operating assets and liabilities, net	(165)	(395)	230
	$ 1,911	$ 3,445	$ (1,534)

Net cash provided by operating activities decreased primarily due to reduced operating activities and a decrease of $633 million associated with cash proceeds from insurance recoveries and cost reimbursements related to the Macondo well incident, partially offset by a decrease of $200 million of cash paid for scheduled installments under our Macondo well incident settlement obligations and increase of $53 million received from customers for early terminations or cancellations of drilling contracts.

	Years ended December 31,		
	2016	2015	Change
	(In millions)		
Cash flows from investing activities			
Capital expenditures	$ (1,344)	$ (2,001)	$ 657
Proceeds from disposal of assets, net	30	54	(24)
Proceeds from repayment of notes receivable	—	15	(15)
Other, net	1	—	1
	$ (1,313)	$ (1,932)	$ 619

Net cash used in investing activities decreased primarily due to reduced capital expenditures, primarily associated with the timing of milestone payments for our major construction projects and other shipyard projects.

	Years ended December 31, 2016	2015	Change
	(In millions)		
Cash flows from financing activities			
Proceeds from issuance of debt, net of discounts and costs	$ 2,401	$ —	$ 2,401
Repayments of debt	(2,295)	(1,506)	(789)
Proceeds from cash and investments restricted for financing activities, net of deposits	39	110	(71)
Distributions of qualifying additional paid-in capital	—	(381)	381
Other, net	(30)	(32)	2
	$ 115	$ (1,809)	$ 1,924

Net cash provided by financing activities increased primarily due to the following: (a) cash proceeds from the issuance of the 9.00% Senior Notes, the 7.75% Senior Secured Notes and the 6.25% Senior Secured Notes in the current year with no comparable activity in the prior year and (b) cash used to pay our shareholders installments of distributions of qualifying additional paid in capital in the prior year with no comparable activity in the current year, partially offset by (c) increased cash used to repay debt in connection with scheduled maturities, our tender offer, open market repurchases and redemption and (d) cash deposited into cash accounts restricted for financing activities, primarily for the payment of principal amounts of our senior secured notes in the current year with no comparable activity in the prior year.

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Sources and uses of liquidity

Overview—We expect to use existing cash balances, internally generated cash flows, borrowings under our existing bank credit agreement, proceeds from the disposal of assets or proceeds from the issuance of additional debt to fulfill anticipated obligations, which may include capital expenditures, working capital and other operational requirements, scheduled debt maturities or other payments. We may also consider establishing additional financing arrangements with banks or other capital providers. Subject to market conditions and other factors, we may also be required to provide collateral for future financing transactions. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may continue to use a portion of our internally generated cash flows and proceeds from asset sales to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, or through debt redemptions or tender offers.

Our access to debt and equity markets may be limited due to a variety of events, including, among others, credit rating agency downgrades of our debt ratings, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. During the year ended December 31, 2015, three credit rating agencies downgraded their credit ratings of our non credit enhanced senior unsecured long term debt ("Debt Rating") to Debt Ratings that are below investment grade. During the year ended December 31, 2016 and in January 2017, the same three credit rating agencies further downgraded our Debt Rating. Such downgrades have caused and the recent downgrades will cause us to experience increased fees under our credit facility and interest rates under agreements governing certain of our senior notes. Further downgrades may affect or limit our ability to access debt markets in the future. Our ability to access such markets may be severely restricted at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. An economic downturn could have an impact on the lenders participating in our credit facilities or on our customers, causing them to fail to meet their obligations to us.

Our internally generated cash flow is directly related to our business and the market sectors in which we operate. Should the drilling market deteriorate, or should we experience poor results in our operations, cash flow from operations may be reduced. We have, however, continued to generate positive cash flow from operating activities over recent years and expect that such cash flow will continue to be positive over the next year.

Debt issuances—On July 21, 2016, we completed an offering of an aggregate principal amount of $1.25 billion of the 9.00% Senior Notes, and we received aggregate cash proceeds of $1.21 billion, net of initial discount and costs payable by us. We used the majority of the net proceeds from the debt offering to complete the Tender Offer (see "Debt tender offer"). We will pay interest on the 9.00% Senior Notes semiannually on January 15 and July 15 each year, beginning on January 15, 2017.

On October 19, 2016 and December 8, 2016, we completed an offering of an aggregate principal amount of $600 million of the 7.75% Senior Secured Notes and $625 million of the 6.25% Senior Secured Notes, respectively, and we received aggregate cash proceeds of $583 million and $609 million, respectively, net of initial discount and costs payable by us. We will pay interest on the 7.75% Senior Secured Notes semiannually on April 15 and October 15 of each year, beginning April 15, 2017. We will pay interest on the 6.25% Senior Secured Notes semiannualy on June 1 and December 1 of each year, beginning June 1, 2017. Additionally, on each interest payment date, we will be required to redeem, on a pro rata basis, an aggregate principal amount of $30 million and $31 million of the 7.75% Senior Secured Notes and the 6.25% Senior Secured Notes, respectively. Additionally, the indentures that govern the 7.75% Senior Secured Notes and the 6.25% Senior Secured Notes contain covenants that limit the ability of our subsidiaries that own or operate the Deepwater Thalassa and Deepwater Proteus to declare or pay dividends and impose a maximum collateral rig leverage ratio ("Maximum Collateral Ratio"), represented by each rig's earnings relative to the debt balance, that changes over the terms of the notes. At December 31, 2016, the Maximum Collateral Ratio under both indentures was 5.75:1.00, and the collateral leverage ratio of each subsidiary was less than

5.00:1.00.

Debt scheduled maturity—On the scheduled maturity date of December 15, 2016, we made a cash payment of $938 million to repay the outstanding 5.05% Senior Notes due December 2016, at a price equal to 100 percent of the aggregate principal amount.

Debt tender offer—On August 1, 2016, we completed the Tender Offer to purchase for cash up to $1.0 billion aggregate principal amount of the Tendered Notes. As a result of the Tender Offer, we received valid tenders from holders of an aggregate principal amount of $981 million of the Tendered Notes, and in the year ended December 31, 2016, we made an aggregate cash payment of $876 million to settle the Tendered Notes.

Debt repurchases and redemption—In the years ended December 31, 2016 and 2015, we repurchased in the open market an aggregate principal amount of $399 million and $503 million, respectively, of our debt securities for an aggregate cash payment of $354 million and $468 million, respectively. On July 30, 2015, we redeemed the remaining aggregate principal amount of $893 million of the 4.95% Senior Notes for an aggregate cash payment of $904 million. During the year ended December 31, 2014, we redeemed an aggregate principal amount of $207 million of the outstanding 4.95% Senior Notes for an aggregate payment of $216 million. We also repaid borrowings under a credit facility, established by one of our subsidiaries, and terminated this credit facility and an undrawn secured credit facility.

Distributions of qualifying additional paid-in capital—In May 2015, at our annual general meeting, our shareholders approved the distribution of qualifying additional paid in capital in the form of a U.S. dollar denominated dividend of $0.60 per outstanding share, payable in four quarterly installments of $0.15 per outstanding share, subject to certain limitations. In May 2015, we recognized a liability of $218 million for the distribution payable, recorded in other current liabilities, with a corresponding entry to additional paid in capital. On June 17 and September 23, 2015, we paid the first two installments in the aggregate amount of $109 million to shareholders of record as of

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May 29, and August 25, 2015. On October 29, 2015, at our extraordinary general meeting, our shareholders approved the cancellation of the third and fourth installments of the distribution.

In May 2014, at our annual general meeting, our shareholders approved the distribution of qualifying additional paid in capital in the form of a U.S. dollar denominated dividend of $3.00 per outstanding share, payable in four quarterly installments, subject to certain limitations. On June 18, September 17 and December 17, 2014, we paid the first three installments in the aggregate amount of $816 million to shareholders of record as of May 30, August 22 and November 14, 2014, respectively. On March 18, 2015, we paid the final installment in the aggregate amount of $272 million to shareholders of record as of February 20, 2015.

In May 2013, at our annual general meeting, our shareholders approved the distribution of qualifying additional paid in capital in the form of a U.S. dollar denominated dividend of $2.24 per outstanding share, payable in four quarterly installments, subject to certain limitations. On March 19, 2014, we paid the final installment in the aggregate amount of $202 million to shareholders of record as of February 21, 2014.

We did not pay the distribution of qualifying additional paid in capital with respect to our shares held in treasury or held by our subsidiary.

Litigation settlements and insurance recoveries—On May 20, 2015, we entered into a confidential settlement agreement with BP plc. together with its affiliates (“BP”) to settle various disputes remaining between the parties with respect to the Macondo well incident. Pursuant to the terms of the agreement, we received from BP a cash payment of $125 million in July 2015 to partially reimburse us for legal fees incurred by us. Additionally, in connection with the settlement, BP agreed to discontinue its attempts to recover as an additional insured under our liability insurance program. As a result, we submitted claims to our insurers and, in the year ended December 31, 2015, we received aggregate cash proceeds of $538 million from insurance for recovery of previously incurred losses.

On May 29, 2015, together with the Plaintiff Steering Committee (the “PSC”), we filed a settlement agreement (the “PSC Settlement Agreement”) in which we agreed to pay a total of $212 million, plus up to $25 million for partial reimbursement of attorneys’ fees, to resolve (1) punitive damages claims of private plaintiffs, businesses, and local governments and (2) certain claims that BP had made against us and had assigned to private plaintiffs who previously settled economic damages claims against BP. The PSC Settlement Agreement is subject to approval by the U.S. District Court for the Eastern District of Louisiana (the “MDL Court”) and acceptance by a minimum number of plaintiffs. In June 2016 and August 2015, we made a cash deposit of $25 million and $212 million, respectively, into an escrow account pending approval of the settlement by the MDL Court. As of February 16, 2017, the aggregate cash balance of our escrow accounts was $237 million.

Effective October 13, 2015, we finalized a settlement agreement with the states of Alabama, Florida, Louisiana, Mississippi and Texas (collectively, the “States”), pursuant to which the States agreed to release all of their claims against us arising from the Macondo well incident. On October 22, 2015, we made an aggregate cash payment of $35 million to the States.

Pursuant to a cooperation guilty plea agreement by and among the U.S. Department of Justice (“DOJ”) and certain of our affiliates (the “Plea Agreement”), which was accepted by the court on February 14, 2013, we agreed to pay a criminal fine of $100 million and to consent to the entry of an order requiring us to pay $150 million to the National Fish & Wildlife Foundation and $150 million to the National Academy of Sciences in scheduled installments through February 2017. In each of the years ended December 31, 2016, 2015 and 2014, we made an aggregate cash payment of $60 million. On February 14, 2017, we made an aggregate cash payment of $60 million, representing the final installment due under the Plea Agreement.

Pursuant to a civil consent decree by and among the DOJ and certain of our affiliates ("the Consent Decree"), which was approved by the court on February 19, 2013, we agreed to pay a civil penalty totaling $1.0 billion, plus interest at a fixed rate of 2.15 percent. In the years ended December 31, 2015 and 2014, we made an aggregate cash payment of $204 million and $412 million, respectively, including interest, representing the final installments due under the Consent Decree.

Noncontrolling interest—On August 5, 2014, we completed the initial public offering of 20.1 million common units representing limited liability company interests in Transocean Partners, which traded on the New York Stock Exchange under the ticker symbol "RIGP". Through Transocean Partners Holdings Limited, a Cayman Islands company and our wholly owned subsidiary, we held the remaining 21.3 million common units and 27.6 million subordinated units and all of the incentive distribution rights. As a result of the offering, we received net cash proceeds of approximately $417 million, after deducting approximately $26 million for underwriting discounts and commissions and other estimated offering expenses.

In the year ended December 31, 2016, Transocean Partners declared and paid an aggregate distribution of $99 million, of which $28 million was paid to holders of noncontrolling interest. In the year ended December 31, 2015, Transocean Partners declared and paid an aggregate distribution of $100 million to its unitholders, of which $29 million was paid to the holders of noncontrolling interest. In the year ended December 31, 2014, Transocean Partners declared and paid an aggregate distribution of $15 million to its unitholders, of which $4 million was paid to the holders of noncontrolling interest.

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On November 4, 2015, Transocean Partners announced that its board of directors approved a unit repurchase program, authorizing it to repurchase up to $40 million of its publicly held common units. Under the program, Transocean Partners repurchased 478,376 of its publicly held common units for an aggregate purchase price of $4 million.

On December 9, 2016, Transocean Partners completed a merger with one of our subsidiaries as contemplated under the Merger Agreement. Following the completion of the merger, Transocean Partners became a wholly owned indirect subsidiary of Transocean Ltd. Each Transocean Partners common unit that was issued and outstanding immediately prior to the closing, other than units held by Transocean and its subsidiaries, was converted into the right to receive 1.20 of our shares. To complete the merger, we issued 23.8 million shares from conditional capital.

Revolving credit facility—In June 2014, we entered into an amended and restated bank credit agreement, which established a $3.0 billion unsecured five year revolving credit facility, that is scheduled to expire on June 28, 2019 (the “Five Year Revolving Credit Facility”). Among other things, the Five Year Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Five Year Revolving Credit Facility also includes a covenant imposing a maximum debt to tangible capitalization ratio of 0.6 to 1.0. At December 31, 2016, our debt to tangible capitalization ratio, as defined, was 0.4 to 1.0. In order to borrow or have letters of credit issued under the Five Year Revolving Credit Facility, we must, at the time of the borrowing request, not be in default under the bank credit agreements and make certain representations and warranties, including with respect to compliance with laws and solvency, to the lenders, but we are not required to make any representation to the lenders as to the absence of a material adverse effect. Repayment of borrowings under the Five Year Revolving Credit Facility is subject to acceleration upon the occurrence of an event of default. We are also subject to various covenants under the indentures pursuant to which our public debt was issued, including restrictions on creating liens, engaging in sale/leaseback transactions and engaging in certain merger, consolidation or reorganization transactions. A default under our public debt indentures, our capital lease contract or any other debt owed to unaffiliated entities that exceeds $125 million could trigger a default under the Five Year Revolving Credit Facility and, if not waived by the lenders, could cause us to lose access to the Five Year Revolving Credit Facility.

We may borrow under the Five Year Revolving Credit Facility at either (1) the adjusted London Interbank Offered Rate (“LIBOR”) plus a margin (the “Five Year Revolving Credit Facility Margin”), which ranges from 1.125 percent to 2.0 percent based on the Debt Rating, or (2) the base rate specified in the credit agreement plus the Five Year Revolving Credit Facility Margin, less one percent per annum. Throughout the term of the Five Year Revolving Credit Facility, we pay a facility fee on the daily unused amount of the underlying commitment which ranges from 0.15 percent to 0.35 percent based on our Debt Rating. At February 16, 2017, based on our Debt Rating on that date, the Five Year Revolving Credit Facility Margin was 2.0 percent and the facility fee was 0.35 percent. At February 16, 2017, we had no borrowings outstanding, no letters of credit issued, and $3.0 billion of available borrowing capacity under the Five Year Revolving Credit Facility.

Share repurchase program—In May 2009, at our annual general meeting, our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, equivalent to approximately $3.4 billion. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. At December 31, 2015, we held 2.9 million of our shares. On October 29, 2015, at our extraordinary general meeting, our shareholders approved the cancellation of all shares repurchased to date under our share repurchase program. In January 2016, upon registration of the cancellation in the commercial register, all repurchased shares were cancelled. In the three year period ended December 31, 2016, we did not purchase shares under our share repurchase program.

We intend to fund any repurchases using available cash balances and cash from operating activities. Based upon our ongoing capital requirements, the price of our shares, regulatory and tax considerations, cash flow generation, the amount and duration of our contract backlog, general market conditions, debt ratings considerations and other factors, we may elect to retain cash, reduce debt, make capital investments or acquisitions or otherwise use cash for general corporate purposes, and consequently, we may elect not to repurchase any additional shares under this program. Decisions regarding the amount, if any, and timing of any share repurchases will be made from time to time based upon these factors. Any repurchased shares under the share repurchase program would be held by us for cancellation by the shareholders at a future general meeting of shareholders. The share repurchase program could be suspended or discontinued by our board of directors or company management, as applicable, at any time. At February 16, 2017, the authorization remaining under the share repurchase program was for the repurchase of up to CHF 3.2 billion, equivalent to approximately $3.2 million of our outstanding shares. See “Item 5. Market for Registrant’s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities—Shareholder Matters.”

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Contractual obligations—At December 31, 2016, our contractual obligations stated at face value, were as follows:

		For the years ending December 31,			
	Total	2017	2018 - 2019	2020 - 2021	Thereafter
	(in millions)				
Contractual obligations					
Debt	$ 7,980	$ 706	$ 1,235	$ 1,305	$ 4,734
Interest on debt	4,915	563	943	857	2,552
Capital lease obligation (a)	903	66	144	143	550
Plea Agreement obligations	60	60	—	—	—
Operating lease obligations	91	10	21	18	42
Purchase obligations	2,004	229	9	1,766	—
Service agreement obligations (b)	542	27	97	106	312
Total (c)	$ 16,495	$ 1,661	$ 2,449	$ 4,195	$ 8,190

(a) Includes scheduled installments of principal and imputed interest on our capital lease obligation.

(b) In the year ended December 31, 2016, we entered into long term service agreements with certain original equipment manufacturers to provide services and parts related to our pressure control systems. The future payments required under our service agreements were estimated based on our projected operating activity and may vary based on actual operating activity.

(c) As of December 31, 2016, our defined benefit pension and other postretirement plans represented an aggregate liability of $375 million, representing the aggregate projected benefit obligation, net of the aggregate fair value of plan assets. The carrying amount of this liability is affected by net periodic benefit costs, funding contributions, participant demographics, plan amendments, significant current and future assumptions, and returns on plan assets. Due to the uncertainties resulting from these factors and since the carrying amount is not representative of future liquidity requirements, we have excluded this amount from the contractual obligations presented in the table above. See "—Pension Plans and Other Postretirement Benefit Plans" and Notes to Consolidated Financial Statements—Note 12—Postemployment Benefit Plans.

As of December 31, 2016, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of $370 million. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in this balance, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities, and we have excluded this amount from the contractual obligations presented in the table above. See Notes to Consolidated Financial Statements—Note 7—Income Taxes.

Other commercial commitments—We have other commercial commitments that we are contractually obligated to fulfill with cash under certain circumstances. These commercial commitments include standby letters of credit and surety bonds that guarantee our performance as it relates to our drilling contracts, insurance, customs, tax and other obligations in various jurisdictions. Standby letters of credit are issued under various uncommitted credit lines, some of which require cash collateral. At December 31, 2016, the aggregate cash collateral held by banks for letters of credit was $5 million. The obligations that are the subject of these standby letters of credit and surety bonds are primarily geographically concentrated in India. Obligations under these standby letters of credit and surety bonds are not normally called, as we typically comply with the underlying performance requirement.

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

	For the years ended December 31,				
	Total	2017	2018 - 2019	2020 - 2021	Thereafter
	(in millions)				
Other commercial commitments					
Standby letters of credit	$ 50	$ 45	$ 5	$ —	$ —
Surety bonds	33	31	2	—	—
Total	$ 83	$ 76	$ 7	$ —	$ —

We have established a wholly owned captive insurance company to insure various risks of our operating subsidiaries. Access to the cash investments of the captive insurance company may be limited due to local regulatory restrictions. At December 31, 2016, the cash investments held by the captive insurance company totaled $209 million, and the amount of such cash investments is expected to range from $75 million to $215 million by December 31, 2017. The amount of actual cash investments held by the captive insurance company varies, depending on the amount of premiums paid to the captive insurance company, the timing and amount of claims paid by the captive insurance company, and the amount of dividends paid by the captive insurance company.

Drilling fleet

Expansion—From time to time, we review possible acquisitions of businesses and drilling rigs and may make significant future capital commitments for such purposes. We may also consider investments related to major rig upgrades, new rig construction, or the acquisition of a rig under construction. We may commit to such investment without first obtaining customer contracts. Any acquisition, upgrade or new rig construction could involve the payment by us of a substantial amount of cash or the issuance of a substantial number of additional shares or other securities. Our failure to secure drilling contracts for rigs under construction could have an adverse effect on our results of operations or cash flows.

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In the years ended December 31, 2016 and 2015, we made capital expenditures of $1.3 billion and $2.0 billion, respectively, including $1.2 billion and $1.6 billion, respectively, for our major construction projects. For the year ending December 31, 2017, we expect total capital expenditures and other capital additions to be approximately $500 million, including $431 million for our major construction projects.

As of December 31, 2016, the historical and projected capital expenditures and other capital additions, including capitalized interest, for our ongoing major construction projects were as follows:

	Total costs through December 31, 2016	For the years ending December 31,				
		2017	2018	2019	2020	Total
	(In millions)					
Deepwater Pontus (a)	$ 745	$ 155	$ —	$ —	$ —	$ 900
Deepwater Poseidon (a)	707	174	29	—	—	910
Transocean Cassiopeia (b)	59	6	3	12	195	275
Ultra-Deepwater drillship TBN1 (c)	221	50	27	62	465	825
Transocean Centaurus (b)	57	6	8	12	207	290
Transocean Cepheus (b)	57	6	8	12	207	290
Ultra-Deepwater drillship TBN2 (c)	166	34	14	36	495	745
Transocean Cetus (b)	54	—	7	10	209	280
Transocean Circinus (b)	53	—	4	10	213	280
Total	$ 2,119	$ 431	$ 100	$ 154	$ 1,991	$ 4,795

(a) Deepwater Pontus and Deepwater Poseidon, two newbuild ultra deepwater drillships under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, are expected to commence operations in the fourth quarter of 2017 and the first quarter of 2018, respectively.

(b) Transocean Cassiopeia, Transocean Centaurus, Transocean Cepheus, Transocean Cetus and Transocean Circinus, five Keppel FELS Super B 400 Bigfoot class design newbuild high specification jackups under construction at Keppel FELS' shipyard in Singapore do not yet have drilling contracts and are expected to be delivered in the first quarter of 2020, the second quarter of 2020, the third quarter of 2020, the fourth quarter of 2020 and the fourth quarter of 2020, respectively. The delivery expectations and the cost projections presented above reflect the terms of our construction agreements, as amended to delay delivery in consideration of current market conditions.

(c) Our two unnamed dynamically positioned ultra deepwater drillships under construction at the Jurong Shipyard Pte Ltd. in Singapore do not yet have drilling contracts and are expected to be delivered in the first quarter of 2020 and the third quarter of 2020, respectively. The delivery expectations and the cost projections presented above reflect the terms of our construction agreements, as amended to delay delivery in consideration of current market conditions.

The ultimate amount of our capital expenditures is partly dependent upon financial market conditions, the actual level of operational and contracting activity, the costs associated with the current regulatory environment and customer requested capital improvements and equipment for which the customer agrees to reimburse us. As with any major shipyard project that takes place over an extended period of time, the actual costs, the timing of expenditures and the project completion date may vary from estimates based on numerous factors, including actual contract terms, weather, exchange rates, shipyard labor conditions, availability of suppliers to recertify equipment and the market demand for components and resources required for drilling unit construction. We intend to fund the cash requirements relating to our capital expenditures through available cash balances, cash generated from operations and asset sales. We also have available credit under the Five Year Revolving Credit Facility and may utilize other commercial bank or capital market financings. Economic conditions could impact the availability of these sources of funding.

Dispositions—From time to time, we may also review the possible disposition of non strategic drilling units. Considering recent market conditions, we have committed to plans to sell certain lower specification drilling units for scrap value. During the years ended December 31, 2016, 2015 and 2014, we identified seven, 22 and two such drilling units, respectively, that we have sold or intend to sell for scrap value. We continue to evaluate the drilling units in our fleet and may identify additional lower-specification drilling units to be sold for scrap value.

During the year ended December 31, 2016, we completed the sale of three deepwater floaters and eight midwater floaters, along with related equipment, and we received aggregate net cash proceeds of $22 million. During the year ended December 31, 2015, we completed the sale of two ultra deepwater floaters, six deepwater floaters and nine midwater floaters, along with related equipment, and we received aggregate net cash proceeds of $35 million. During the year ended December 31, 2014, we completed the sale of one deepwater floater, one midwater floater and two high specification jackups, along with related equipment, and we received aggregate net cash proceeds of $185 million.

Pension Plans and Other Postretirement Benefit Plans

Overview—Benefits under all of our U.S. defined benefit pension plans have ceased accruing. We maintain the respective pension obligations under such plans until they have been fully satisfied. As of December 31, 2016, we maintained three funded and three unfunded defined benefit plans in the U.S. (the “U.S. Plans”). During the year ended December 31, 2016, we permitted certain participants of one of our funded U.S. Plans to make a one time election to receive a payment of retirement benefits in the form of either (a) a lump sum distribution or (b) an annuity starting October 1, 2016.

As of December 31, 2016, we maintained one defined benefit plan in the U.K. (the "U.K. Plan"), under which we and the plan trustees mutually agreed to cease accruing benefits effective March 31, 2016. As of December 31, 2016, we also maintained two funded and two unfunded defined benefit plans, primarily group pension schemes with life insurance companies, which cover certain eligible Norway employees and former employees (the "Norway Plans"). During the year ended December 31, 2016, we satisfied our obligations under four funded defined benefit plans in Norway and the unfunded defined benefit plans in Nigeria. During the year ended December 31, 2015, we satisfied our obligations under the unfunded defined benefit plans in Egypt and Indonesia. We refer to the U.K. Plan, the Norway Plans and the plans in Nigeria, Egypt and Indonesia, collectively, as the "Non U.S. Plans."

We refer to the U.S. Plans and the Non U.S. Plans, collectively, as the "Transocean Plans." Additionally, we maintain certain unfunded other postretirement employee benefit plans (collectively, the "OPEB Plans"), under which benefits to eligible participants diminish during a phase out period ending December 31, 2025.

The following table presents the amounts and weighted average assumptions associated with the U.S. Plans, the Non U.S. Plans and the OPEB Plans.

	Year ended December 31, 2016				Year ended December 31, 2015			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Net periodic benefit costs	$ (3)	$ (4)	$ (4)	$ (11)	$ (3)	$ 30	$ (1)	$ 26
Other comprehensive income (loss) (a)	(35)	25	(2)	(12)	(20)	80	29	89
Employer contributions	3	43	3	49	13	21	5	39
At end of period:								
Accumulated benefit obligation	$ 1,557	$ 396	$ 19	$ 1,972	$ 1,523	$ 458	$ 24	$ 2,005
Projected benefit obligation	1,557	398	19	1,974	1,523	502	24	2,049
Fair value of plan assets	1,204	400	—	1,604	1,198	439	—	1,637
Funded status	(353)	2	(19)	(370)	(325)	(63)	(24)	(412)
Accumulated comprehensive income (loss) (a)	(316)	(94)	23	(387)	(281)	(119)	25	(375)
Weighted-Average Assumptions -Net periodic benefit costs								
Discount rate (b)	4.56 %	3.69 %	3.13 %	4.37 %	4.16 %	3.26 %	3.86 %	3.95 %
	6.82 %	5.85 %	na	6.57 %	7.79 %	5.93 %	na	7.33 %

Long-term rate of return (c)								
Compensation trend rate (b)	0.22 %	4.01 %	na	0.98 %	0.21 %	3.83 %	na	1.04 %
Health care cost trend rate-initial	na	na	na	na	na	na	7.81 %	7.81 %
Health care cost trend rate-ultimate	na	na	na	na	na	na	5.00 %	5.00 %
-Benefit obligations								
Discount rate (b)	4.26 %	2.69 %	3.08 %	3.94 %	4.55 %	3.59 %	3.13 %	4.30 %
Compensation trend rate (b)	na	2.25 %	na	2.25 %	3.82 %	3.77 %	na	3.79 %

“na” means not applicable.

(a) Amounts presented before tax.
(b) Weighted average based on relative average projected benefit obligation for the year.
(c) Weighted average based on relative average fair value of plan assets for the year.

Net periodic benefit cost—In the years ended December 31, 2016 and 2015, net periodic benefit costs were reduced by $105 million and $115 million, respectively, for expected returns from plan assets. In the year ended December 31, 2016, net periodic benefit costs decreased $37 million. In the year ending December 31, 2017, we expect our net periodic benefit costs to be approximately the same as the costs recognized in the year ended December 31, 2016.

Plan assets—In the year ended December 31, 2016, plan assets of the funded Transocean Plans were favorably impacted by improvements in world equity markets, given the allocation of approximately 50 percent of plan assets to equity securities. To a lesser extent, plan assets allocated to debt securities and other investments also experienced better than expected gains. In the year ended December 31, 2016, the fair value of the investments in the funded Transocean Plans decreased by $33 million, or two percent, primarily due to the following: $130 million resulting from benefits and settlements paid from plan assets, net of contributions, and $80 million resulting from net losses on currency exchange rate changes for our non U.S. Plans, partially offset by $177 million resulting from investment returns.

Funding contributions—We review the funded status of our plans at least annually and contribute an amount at least equal to the minimum amount required. For the funded qualified U.S. Plan, we contribute an amount at least equal to that required by the Employee Retirement Income Security Act of 1974 (“ERISA”) and the Pension Protection Act of 2006 (“PPA”). We use actuarial computations to

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establish the minimum contribution required under ERISA and PPA and the maximum deductible contribution allowed for income tax purposes. For the funded U.K. Plan, we contribute an amount, as mutually agreed with the plan trustees, based on actuarial recommendations. For the funded Norway Plans, we contribute an amount determined by the plan trustee based on Norwegian pension laws. For the unfunded Transocean Plans and OPEB Plans, we generally fund benefit payments for plan participants as incurred. We fund our contributions to the Transocean Plans and the OPEB Plans using cash flows from operations.

In the year ended December 31, 2016, we contributed $49 million and participants contributed $1 million to the Transocean Plans and the OPEB Plans. In the year ended December 31, 2015, we contributed $39 million and participants contributed $4 million to the Transocean Plans and the OPEB Plans. For the year ending December 31, 2017, we expect to contribute $11 million to the Transocean Plans and $3 million to the OPEB Plans.

See Notes to Consolidated Financial Statements—Note 12—Postemployment Benefit Plans.

Contingencies and Uncertainties

Macondo well incident

A significant portion of the contingencies arising from the Macondo well incident has now been resolved as a result of settlements with the DOJ, BP and the States. Additionally, we entered into the PSC Settlement Agreement, which remains subject to approval by the MDL Court. We believe the remaining most notable claims against us arising from the Macondo well incident are the 30 settlement class opt outs from the PSC Settlement Agreement. We can provide no assurance as to the outcome of the remaining claims arising from the Macondo well incident, the timing of any upcoming appeal or further rulings, or that we will not enter into additional settlements as to some or all of the remaining matters related to the Macondo well incident. See Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies and Note 23—Subsequent Events.

Regulatory matters

On February 25, 2013, we and the U.S. Environmental Protection Agency (the "EPA") entered into an agreement (the "EPA Agreement"), which has a five year term. Subject to our compliance with the terms of the EPA Agreement, the EPA agreed that it will not suspend, debar or statutorily disqualify us and will lift any existing suspension, debarment or statutory disqualification. In the EPA Agreement, we agreed to comply with our obligations under the Plea Agreement and the Consent Decree and continue the implementation of certain programs and systems designed to enhance our environmental management systems and improve our environmental performance. We also agreed to other specified actions, including the (i) scheduled revision of our environmental management system and maintenance of certain compliance and ethics programs; (ii) compliance with certain employment and contracting procedures, (iii) engagement of an independent compliance auditor to, among other things, assess and report to the EPA on our compliance with the terms of the Plea Agreement, the Consent Decree and the EPA Agreement and (iv) provision of reports and notices with respect to various matters, including those related to compliance, misconduct, legal proceedings, audit reports, the EPA Agreement, the Consent Decree and the Plea Agreement. The EPA Agreement prohibits us from entering into, extending or engaging in certain business relationships with individuals or entities that are debarred, suspended, proposed for debarment or similarly restricted. For a description of regulatory and environmental matters relating to the Macondo well incident, please see "—Macondo well incident." See also Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies.

Tax matters

We conduct operations through our 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, we may identify changes to previously evaluated tax positions that could result in adjustments to our recorded assets and liabilities. Although we are unable to predict the outcome of these changes, we do not expect the effect, if any, resulting from these adjustments to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

We file federal and local tax returns in several jurisdictions throughout the world. Tax authorities in certain jurisdictions are examining our tax returns and in some cases have issued assessments. We are defending our tax positions in those jurisdictions. We are also defending against tax related claims in courts, including our ongoing civil trial in Norway. In January 2016, the Norwegian authorities formally and unconditionally dropped all criminal charges against our subsidiaries and the two employees of our former external advisors and our former external Norwegian attorney. As a result, no criminal charges remain outstanding for any of the previously reported Norway tax investigations or trials and all our subsidiaries and external advisors have been fully acquitted of all criminal charges. On January 9, 2017, the Norwegian appeal court in Oslo ruled entirely in favor of the Transocean subsidiaries and overturned the district court with respect to the remaining question of principal tax obligations. On February 10, 2017, the tax authorities filed an appeal with the Norwegian Supreme Court. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate liability to have a material adverse effect on our consolidated statement of financial position or results of operations, although it may have a material adverse effect on our consolidated cash flows.

See Notes to Consolidated Financial Statements—Note 7—Income Taxes and Note 23—Subsequent Events.

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Other matters

In addition, from time to time, we receive inquiries from governmental regulatory agencies regarding our operations around the world, including inquiries with respect to various tax, environmental, regulatory and compliance matters. To the extent appropriate under the circumstances, we investigate such matters, respond to such inquiries and cooperate with the regulatory agencies.

Off Balance Sheet Arrangements

We had no off balance sheet arrangements as of December 31, 2016.

Related Party Transactions

As of December 31, 2016, we did not have any material related party transactions that were not in the ordinary course of business.

Critical Accounting Policies and Estimates

Overview—We consider the following to be our critical accounting policies and estimates since they are very important to the portrayal of our financial condition and results and require our most subjective and complex judgments. We have discussed the development, selection and disclosure of such policies and estimates with the audit committee of our board of directors. For a discussion of our significant accounting policies, refer to our Notes to Consolidated Financial Statements—Note 2—Significant Accounting Policies.

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the U.S., which require us to make estimates that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures of contingent assets and liabilities. These estimates require significant judgments and assumptions. We base our estimates on historical experience and on various other 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.

Income taxes—We are a Swiss corporation, operating through our various subsidiaries in a number of countries throughout the world. We provide for income taxes based upon the tax laws and rates in the countries in which we operate and earn income. The relationship between the provision for or benefit from income taxes and our income or loss before income taxes can vary significantly from period to period because the countries in which we operate have taxation regimes that vary with respect to the nominal tax rate and the availability of deductions, credits and other benefits. Generally, our annual marginal tax rate is lower than our annual effective tax rate. Consequently, our income tax expense does not change proportionally with our income before income taxes. Variations also arise when income earned and taxed in a particular country or countries fluctuates from year to year.

Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination of our annual tax provision and evaluation of our tax positions involves interpretation of tax laws in the various jurisdictions and requires significant judgment and the use of estimates and assumptions regarding significant future events, such as the amount, timing and character of income, deductions and tax credits. Our tax liability in any given year could be affected by changes in tax laws, regulations, agreements, and treaties, currency exchange restrictions or our level of operations or profitability in each jurisdiction. Additionally, we operate in many jurisdictions where the tax laws relating to the offshore drilling industry are not well developed. Although our annual tax provision is based on the best information available at the time, a number of years may elapse before the tax liabilities in the various jurisdictions are ultimately determined.

We maintain liabilities for estimated tax exposures in our jurisdictions of operation, and the provisions and benefits resulting from changes to those liabilities are included in our annual tax provision along with related interest. Tax exposure items include potential challenges to permanent establishment positions, intercompany pricing, disposition transactions, and withholding tax rates and their applicability. These exposures are resolved primarily through the settlement of audits within these tax jurisdictions or by judicial means, but can also be affected by changes in applicable tax law or other factors, which could cause us to revise past estimates. At December 31, 2016, the liability for estimated tax exposures in our jurisdictions of operation was approximately $370 million.

We are currently undergoing examinations in a number of taxing jurisdictions for various fiscal years. We review our liabilities on an ongoing basis and, to the extent audits or other events cause us to adjust the liabilities accrued in prior periods, we recognize those adjustments in the period of the event. We do not believe it is possible to reasonably estimate the future impact of changes to the assumptions and estimates related to our annual tax provision because changes to our tax liabilities are dependent on numerous factors that cannot be reasonably projected. These factors include, among others, the amount and nature of additional taxes potentially asserted by local tax authorities; the willingness of local tax authorities to negotiate a fair settlement through an administrative process; the impartiality of the local courts; and the potential for changes in the taxes paid to one country that either produce, or fail to produce, offsetting tax changes in other countries.

We do not provide for taxes on unremitted earnings of subsidiaries when we consider such earnings to be indefinitely reinvested. We recognize deferred taxes related to the earnings of certain subsidiaries that we do not consider to be indefinitely reinvested or that will not be permanently reinvested in the future. If facts and circumstances cause us to change our expectations regarding future tax consequences, the resulting adjustments to our deferred tax balances could have a material effect on our consolidated statement of financial

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position, results of operations or cash flows. At December 31, 2016, the amount of indefinitely reinvested earnings was approximately $2.5 billion. Should we make a distribution from the unremitted earnings of these subsidiaries, we could be subject to taxes payable to various jurisdictions. We estimate taxes in the range of $200 million to $250 million would be payable upon distribution of all previously unremitted earnings at December 31, 2016.

Estimates, judgments and assumptions are required in determining whether deferred tax assets will be fully or partially realized. In evaluating our ability to realize deferred tax assets, we consider all available positive and negative evidence, including projected future taxable income and the existence of cumulative losses in recent years. When it is estimated to be more likely than not that all or some portion of certain deferred tax assets, such as foreign tax credit carryovers or net operating loss carryforwards, will not be realized, we establish a valuation allowance for the amount of the deferred tax assets that is considered to be unrealizable. We continually evaluate strategies that could allow for the future utilization of our deferred tax assets. During the year ended December 31, 2016, in evaluating our projected realizability of deferred tax assets, we took into account plans to combine certain subsidiaries. During the year ended December 31, 2015, in evaluating our future realization of deferred tax assets we took into account plans to centralize ownership of certain rigs among our subsidiaries, which resulted in utilization of additional deferred tax assets against income from operations. During the year ended December 31, 2014, we did not make any significant changes to our valuation allowance against deferred tax assets.

See Notes to Consolidated Financial Statements—Note 7—Income Taxes.

Property and equipment—The carrying amount of property and equipment is subject to various estimates, assumptions, and judgments related to capitalized costs, useful lives and salvage values and impairments. At December 31, 2016 and 2015, the carrying amount of our property and equipment was $21.1 billion and $20.8 billion, representing 78 percent and 79 percent, respectively, of our total assets.

Capitalized costs—We capitalize costs incurred to enhance, improve and extend the useful lives of our property and equipment and expense costs incurred to repair and maintain the existing condition of our rigs. For newbuild construction projects, we also capitalize the initial preparation, mobilization and commissioning costs incurred until the drilling unit is placed into service. Capitalized costs increase the carrying amounts and depreciation expense of the related assets, which also impact our results of operations.

Useful lives and salvage values—We depreciate our assets using the straight line method over their estimated useful lives after allowing for salvage values. We estimate useful lives and salvage values by applying judgments and assumptions that reflect both historical experience and expectations regarding future operations, rig utilization and asset performance. Useful lives and salvage values of rigs are difficult to estimate due to a variety of factors, including (a) technological advances that impact the methods or cost of oil and gas exploration and development, (b) changes in market or economic conditions, and (c) changes in laws or regulations affecting the drilling industry. Applying different judgments and assumptions in establishing the useful lives and salvage values would likely result in materially different net carrying amounts and depreciation expense for our assets. We reevaluate the remaining useful lives and salvage values of our rigs when certain events occur that directly impact the useful lives and salvage values of the rigs, including changes in operating condition, functional capability and market and economic factors. When evaluating the remaining useful lives of rigs, we also consider major capital upgrades required to perform certain contracts and the long term impact of those upgrades on future marketability. At December 31, 2016, a hypothetical one year increase in the useful lives of all of our rigs would cause a decrease in our annual depreciation expense of approximately $49 million and a hypothetical one year decrease would cause an increase in our annual depreciation expense of approximately $53 million.

Long lived asset impairment—We review our property and equipment for impairment when events or changes in circumstances indicate that the carrying amounts of our assets held and used may not be recoverable or when carrying amounts of assets held for sale exceed fair value less cost to sell. Potential impairment indicators include rapid declines in commodity prices and related market conditions, declines in dayrates or utilization, cancellations of contracts or credit concerns of multiple customers. During periods of oversupply, we may idle or stack rigs for extended periods of time or we may elect to sell certain rigs for scrap, which could be an indication that an asset group may be impaired since supply and demand are the key drivers of rig utilization and our ability to contract our rigs at economical rates. Our rigs are mobile units, equipped to operate in geographic regions throughout the world and, consequently, we may move rigs from an oversupplied market sector to a more lucrative and undersupplied market sector when it is economical to do so. Many of our contracts generally allow our customers to relocate our rigs from one geographic region to another, subject to certain conditions, and our customers utilize this capability to meet their worldwide drilling requirements. Accordingly, our rigs are considered to be interchangeable within classes or asset groups, and we evaluate impairment by asset group. We consider our asset groups to be ultra deepwater floaters, harsh environment floaters, deepwater floaters, midwater floaters, and high specification jackups.

We assess recoverability of assets held and used by projecting undiscounted cash flows for the asset group being evaluated. When the carrying amount of the asset group is determined to be unrecoverable, we recognize an impairment loss, measured as the amount by which the carrying amount of the asset group exceeds its estimated fair value. To estimate the fair value of each asset group, we apply a variety of valuation methods, incorporating income, market and cost approaches. We may weight the approaches, under certain circumstances, when relevant data is limited, when results are inconclusive or when results deviate significantly. Our estimate of fair value generally requires us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the long-term future performance of our asset groups, such as projected revenues and costs, dayrates, rig utilization and revenue

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efficiency. These projections involve uncertainties that rely on assumptions about demand for our services, future market conditions and technological developments. Because our business is cyclical in nature, the results of our impairment testing are expected to vary significantly depending on the timing of the assessment relative to the business cycle. Altering either the timing of or the assumptions used to estimate fair value and significant unanticipated changes to the assumptions could materially alter an outcome that could otherwise result in an impairment loss. Given the nature of these evaluations and their application to specific asset groups and specific time periods, it is not possible to reasonably quantify the impact of changes in these assumptions.

In the year ended December 31, 2016, we recognized a loss of $52 million, which had no tax effect, associated with the impairment of the deepwater floater asset group. In the year ended December 31, 2015, we recognized losses of $507 million ($481 million, net of tax) and $668 million ($654 million, net of tax) associated with the impairment of the deepwater floater asset group and the midwater floater asset group, respectively. In the year ended December 31, 2014, we recognized a loss of $788 million ($693 million, net of tax) associated with the impairment of the deepwater floater asset group.

See Notes to Consolidated Financial Statements—Note 6 Impairments.

Revenue recognition—Our contracts to provide offshore drilling services are individually negotiated and vary in their terms and provisions. We obtain most of our drilling contracts through competitive bidding against other contractors and direct negotiations with operators. Drilling contracts generally provide for payment on a dayrate basis, with higher rates for periods while the drilling unit is operating and lower rates or zero rates for periods of mobilization or when drilling operations are interrupted or restricted by equipment breakdowns, adverse environmental conditions or other conditions beyond our control. A dayrate drilling contract generally extends over a period of time covering either the drilling of a single well or group of wells or covering a stated term. We recognize operating revenues as they are realized and earned and can be reasonably measured, based on contractual dayrates, and when collectability is reasonably assured. For contractual daily rate contracts, we recognize the losses for loss contracts as such losses are incurred.

Certain of our drilling contracts may be cancelable for the convenience of the customer upon payment of an early termination payment. We recognize revenues, presented in other revenues, associated with cancellations or early terminations over the period in which we satisfy our performance obligations based on the negotiated or contractual terms, which are typically specific to the contractual arrangement. In the years ended December 31, 2016 and 2015, we recognized revenues of $471 million and $505 million, respectively, associated with cancellations and early terminations.

Contingencies—We perform assessments of our contingencies on an ongoing basis to evaluate the appropriateness of our liabilities and disclosures for such contingencies. We establish liabilities for estimated loss contingencies when we believe a loss is probable and the amount of the probable loss can be reasonably estimated. We recognize corresponding assets for loss contingencies that we believe are probable of being recovered through insurance. Once established, we adjust the carrying amount of a contingent liability upon the occurrence of a recognizable event when facts and circumstances change, altering our previous assumptions with respect to the likelihood or amount of loss. We recognize liabilities for legal costs as they are incurred, and we recognize a corresponding asset for those legal costs only if we expect such legal costs to be recovered through insurance. Our estimates involve a significant amount of judgement. Actual results may differ from our estimates.

We have recognized a liability for estimated loss contingencies associated with litigation and investigations resulting from the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. The litigation and investigations also give rise to certain loss contingencies that we believe are reasonably possible. Although we have not recognized a liability for such loss contingencies, these contingencies could increase the liabilities we ultimately recognize. As of December 31, 2016 and 2015, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $250 million, recorded in other current liabilities.

See Notes to Consolidated Financial Statements—Note 13—Commitments and Contingencies.

Pension and other postretirement benefits—We use a January 1 measurement date for net periodic benefit costs and a December 31 measurement date for projected benefit obligations and plan assets. We measure our pension liabilities and related net periodic benefit costs using actuarial assumptions based on a market related value of assets that reduces year to year volatility. In applying this approach, we recognize investment gains or losses subject to amortization over a five year period beginning with the year in which they occur. Investment gains or losses for this purpose are measured as the difference between the expected and actual returns calculated using the market related value of assets. If gains or losses exceed 10 percent of the greater of plan assets or plan liabilities, we amortize such gains or losses over the average expected future service period of the employee participants. Actual results may differ from these measurements under different conditions or assumptions. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact our future pension obligations and net periodic benefit costs.

Additionally, the pension obligations and related net periodic benefit costs for our defined benefit pension and other postretirement benefit plans are actuarially determined and are affected by assumptions, including long term rate of return, discount rates, mortality rates and employee turnover rates. Because our defined benefit plans have ceased accruing benefits, certain assumptions, including compensation increases and health care cost trend rates no longer apply. The two most critical assumptions are the long term rate of return and the discount rate. For the long term rate of return of plan assets, we develop our assumptions based on historical experience and

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projected returns for the investments considering each plan's target asset allocation and long term asset class expected returns. For the discount rate, we develop our assumptions utilizing a yield curve approach based on Aa rated corporate bonds and the expected timing of future benefit payments. We periodically evaluate our assumptions and, when appropriate, adjust the recorded liabilities and expense. Changes in these and other assumptions used in the actuarial computations could impact our projected benefit obligations, pension liabilities, net periodic benefit costs and other comprehensive income. See "—Pension Plans and Other Postretirement Benefit Plans" and Notes to Consolidated Financial Statements—Note 12—Postemployment Benefit Plans.

New Accounting Pronouncements

For a discussion of the new accounting pronouncements that have had or are expected to have an effect on our consolidated financial statements, see Notes to Consolidated Financial Statements—Note 3—New Accounting Pronouncements.

Item 7A.Quantitative and Qualitative Disclosures About Market Risk

Overview—We are exposed to interest rate risk and currency exchange rate risk, primarily associated with our restricted cash investments and our long term and short term debt. For our restricted cash investments and debt instruments, the following table presents the principal cash flows and related weighted-average interest rates by contractual maturity date. The information is stated in U.S. dollar equivalents. The instruments are denominated in either U.S. dollars or Norwegian kroner, as indicated. The following table presents information for the years ending December 31
(in millions, except interest rate percentages):

	Scheduled Maturity Date (a)							
	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
Restricted cash investments								
Fixed rate (NOK)	$ 98	$ 25	$ —	$ —	$ —	$ —	$ 123	$ 125
Average interest rate	4.15%	4.15 %	— %	— %	— %	— %		
Debt								
Fixed rate (USD)	$ 633	$ 1,117	$ 155	$ 665	$ 712	$ 5,141	$ 8,423	$ 8,093
Average interest rate	5.11%	6.41 %	7.14%	6.66%	8.10%	7.59 %		
Fixed rate (NOK)	$ 98	$ 25	$ —	$ —	$ —	$ —	$ 123	$ 125
Average interest rate	4.15%	4.15 %	— %	— %	— %	— %		

(a) Expected maturity amounts are based on the face value of debt.

Interest rate risk—At December 31, 2016 and 2015, the fair value of our debt was $8.2 billion and $6.3 billion, respectively. During the year ended December 31, 2016, the fair value of our debt increased by $1.9 billion due to the following: (a) an increase of approximately $2.6 billion resulting from the issuance of $2.5 billion aggregate principal amount of new debt during 2016, (b) a decrease of approximately $1.9 billion resulting from the repurchase or redemption of $2.3 billion aggregate principal amount of debt and (c) an increase of approximately $1.2 billion resulting from the increased fair value of our outstanding debt.

A large portion of our cash investments is subject to variable interest rates and would earn commensurately higher rates of return if interest rates increase. Based upon the amounts of our cash investments as of December 31, 2016 and 2015, a hypothetical one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $31 million and $23 million, respectively.

Currency exchange rate risk—We are exposed to currency exchange rate risk associated with our international operations and with some of our long term and short term debt.

For our international operations, our primary currency exchange rate risk management strategy involves structuring customer contracts to provide for payment in both U.S. dollars, which is our functional currency, and local currency. The payment portion denominated in local currency is based on our anticipated local currency needs over the contract term. Due to various factors, including customer contract terms, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual local currency needs may vary, resulting in exposure to currency exchange rate risk. The effect of fluctuations in currency exchange rates caused by our international operations generally has not had a material impact on our overall operating results.

At December 31, 2016, we had NOK 1.1 billion aggregate principal amount of debt obligations, all of which were secured by a corresponding amount of restricted cash investments that were also denominated in Norwegian kroner. These corresponding restricted cash investments form an economic hedge of our exposure to currency exchange rate risk associated with these debt obligations.

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Item 8.Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Transocean Ltd. (the "Company" or "our") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a 15(e) and 15d 15(e) under the Securities Exchange Act of 1934. The Company's internal control system was designed to provide reasonable assurance to the Company's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with United States ("U.S.") generally accepted accounting principles.

Internal control over financial reporting includes the controls themselves, monitoring (including internal auditing practices), and actions taken to correct deficiencies as identified.

There are inherent limitations to the effectiveness of internal control over financial reporting, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a system of internal control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria for internal control over financial reporting described in Internal Control Integrated Framework, as published in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of the Company's internal control over financial reporting and testing of the operating effectiveness of its internal control over financial reporting.

Management reviewed the results of its assessment with the audit committee of the Company's board of directors. Based on this assessment, management has concluded that, as of December 31, 2016, the Company's internal control over financial reporting was not effective. Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2016, our internal control over financial reporting was not effective due to a material weakness in our controls over income tax accounting. Specifically, the execution of the controls over the application of the accounting literature to the measurement of deferred taxes did not operate effectively in relation to: (1) the remeasurement of certain nonmonetary assets in Norway, (2) the analysis of our U.S. defined benefit pension plans liability and associated other comprehensive income and (3) the realizability of our deferred tax assets and the need for a valuation allowance. As a result of the significance of the accounting errors resulting from the deficient controls, the accompanying financial statements for 2015 and 2014 have been revised notwithstanding that management does not believe that such errors were material for these years. The matter was discovered during the course of the 2016 external audit of the accounts and related controls.

The Company's independent auditors, Ernst & Young LLP, a registered public accounting firm, are appointed by the audit committee of the Company's board of directors, subject to ratification by our shareholders. Ernst & Young LLP has audited and reported on the consolidated financial statements of Transocean Ltd. and Subsidiaries, and the Company's internal control over financial reporting. The reports of the independent auditors are contained in this annual report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Transocean Ltd.

We have audited Transocean Ltd. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Transocean Ltd. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment. Management has identified a material weakness in controls related to the Company's income tax process. We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Transocean Ltd. and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2016. This material weakness was considered in determining the nature, timing and extent of audit tests applied in our audit of the 2016 financial statements, and this report does not affect our report dated March 6, 2017 which expressed an unqualified opinion on those financial statements.

In our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Transocean Ltd. and subsidiaries has not maintained effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

/s/ Ernst & Young LLP

Houston, Texas

March 6, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Transocean Ltd.

We have audited the accompanying consolidated balance sheets of Transocean Ltd. and subsidiaries (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's Board of Directors and management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Transocean Ltd. and subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Transocean Ltd. and subsidiaries’ internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 6, 2017 expressed an adverse opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

March 6, 2017

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share data)

	Years ended December 31, 2016	2015	2014
Operating revenues			
Contract drilling revenues	$ 3,705	$ 6,802	$ 8,963
Other revenues	456	584	222
	4,161	7,386	9,185
Costs and expenses			
Operating and maintenance	1,875	2,955	5,100
Depreciation	893	963	1,129
General and administrative	172	192	234
	2,940	4,110	6,463
Loss on impairment	(93)	(1,875)	(4,043)
Gain (loss) on disposal of assets, net	4	(36)	(26)
Operating income (loss)	1,132	1,365	(1,347)
Other income (expense), net			
Interest income	20	22	20
Interest expense, net of amounts capitalized	(409)	(432)	(483)
Gain (loss) on retirement of debt	148	23	(13)
Other, net	43	37	35
	(198)	(350)	(441)
Income (loss) from continuing operations before income tax expense	934	1,015	(1,788)
Income tax expense	107	120	92
Income (loss) from continuing operations	827	895	(1,880)
Income (loss) from discontinued operations, net of tax	—	2	(20)
Net income (loss)	827	897	(1,900)
Net income (loss) attributable to noncontrolling interest	49	32	(61)
Net income (loss) attributable to controlling interest	$ 778	$ 865	$ (1,839)