Transocean Ltd.
Form 10-K
February 25, 2016
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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, 2015

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	1214

Vernier, Switzerland	
(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
	SIX Swiss Exchange

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

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, 2015, 363,461,097 shares were outstanding and the aggregate market value of shares held by non affiliates was approximately $5.9 billion (based on the reported closing market price of the shares of Transocean Ltd. on June 30, 2015 of $16.12 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 16, 2016, 364,113,962 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, 2015, for its 2016 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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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, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"). 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;
§ 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;
§ any potential reduction to the amount of cash and cash equivalents we reserve for working capital and other needs related to the operation of our business;
§ 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, 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 impact of regulatory changes;
- the cancellation of drilling contracts currently included in our reported contract backlog;
- 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 11, 2016, we owned or had partial ownership interests in and operated 61 mobile offshore drilling units. As of February 11, 2016, our fleet consisted of 28 ultra deepwater floaters, seven harsh environment floaters, five deepwater floaters, 11 midwater floaters and 10 high specification jackups. At February 11, 2016, we also had six 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 (“NYSE”) under the symbol “RIG” and on the SIX Swiss Exchange (“SIX”) under the symbol “RIGN” (see “—Recent Developments”). For information about th 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 22—Operating Segments, Geographical Analysis and Major Customers.”

Recent Developments

On November 23, 2015, we announced our intent to delist our shares from the SIX, and on December 17, 2015, we announced that the SIX listing authorities approved our application to delist our shares. Such delisting is expected to become effective on March 31, 2016, with the last trading day scheduled to be March 30, 2016. Our shares will continue to be listed and traded on the NYSE.

On October 29, 2015, shareholders at our extraordinary general meeting 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 par value reduction became effective as of January 7, 2016 upon registration in the commercial register.

On August 5, 2014, we completed an initial public offering to sell a noncontrolling interest in Transocean Partners LLC (“Transocean Partners”), a consolidated Marshall Islands limited liability company, which trades on the NYSE under the ticker symbol “RIGP”. Through Transocean Partners Holdings Limited, a Cayman Islands company and our wholly owned subsidiary, we hold the controlling interest with 21.3 million common units and 27.6 million subordinated units and all of the incentive distribution rights. See “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Noncontrolling Interest.”

Drilling Fleet

Fleet overview—Most of our drilling equipment is suitable for both exploration and development drilling, and we normally engage in both types of drilling activity. Likewise, 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. Our drilling fleet can be generally characterized as follows: (1) floaters, including drillships and semisubmersibles, and (2) jackups.

Drillships are generally self propelled vessels, shaped like conventional ships, and are the most mobile of the major rig types. All of our high specification drillships are 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. Drillships 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 13 ultra deepwater drillships in operation that are, and six 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, four of our six newbuild drillships under construction will be outfitted to accommodate a future upgrade to a 20,000 pounds per square inch (“psi”) blowout preventer.

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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 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, which are designed for mild environments and are equipped with the unique tri act derrick. The tri act derrick was designed to reduce overall well construction costs, as 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. Additionally, five of our 30 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 11, 2016, we owned and operated a fleet of 61 rigs, excluding rigs under construction, as follows:

§ 28 ultra deepwater floaters;
§ Seven harsh environment floaters;
§ Five deepwater floaters;
§ 11 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 30 to 60 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 11, 2016, 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 11, 2016, 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 (11)

Name	Type	Expected completion	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Ultra-deepwater floaters					
Deepwater Proteus	HSD	2Q 2016	12,000	40,000	To be determined
Deepwater Pontus	HSD	4Q 2017	12,000	40,000	To be determined
Deepwater Poseidon	HSD	1Q 2018	12,000	40,000	To be determined
Deepwater Conqueror	HSD	4Q 2016	12,000	40,000	U.S. Gulf
Ultra-Deepwater drillship TBN1	HSD	2Q 2019	12,000	40,000	To be determined
Ultra-Deepwater drillship TBN2	HSD	1Q 2020	12,000	40,000	To be determined
High-specification jackups					
Transocean Cassiopeia	Jackup	1Q 2018	400	35,000	To be determined
Transocean Centaurus	Jackup	3Q 2018	400	35,000	To be determined
Transocean Cepheus	Jackup	1Q 2019	400	35,000	To be determined
Transocean Cetus	Jackup	3Q 2019	400	35,000	To be determined
Transocean Circinus	Jackup	1Q 2020	400	35,000	To be determined

"HSD" means high specification drillship.

Ultra deepwater floaters (28)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Deepwater Thalassa (b) (c) (d) (e)	HSD	2016	12,000	40,000	U.S. Gulf
Deepwater Asgard (b) (c) (d)	HSD	2014	12,000	40,000	U.S. Gulf
Deepwater Invictus (b) (c) (d)	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)	HSD	2010	12,000	40,000	U.S. Gulf
Discoverer India (b) (c) (d)	HSD	2010	12,000	40,000	U.S. Gulf
Discoverer Americas (b) (c) (d)	HSD	2009	12,000	40,000	Idle
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	Idle
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	Myanmar
Deepwater Pathfinder (b)	HSD	1998	10,000	30,000	Stacked
Cajun Express (b) (g)	HSS	2001	8,500	35,000	Ivory Coast
Deepwater Nautilus (h)	HSS	2000	8,000	30,000	U.S. Gulf
Discoverer Luanda (b) (c) (d) (h)	HSD	2010	7,500	40,000	Angola
Development Driller III (b) (c) (f)	HSS	2009	7,500	37,500	U.S. Gulf
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	Angola
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) Owned through our 71 percent interest in Transocean Partners.
(g) Express class rig.
(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
Transocean Spitsbergen (b) (c)	HSS	2010	10,000	30,000	Norwegian N. Sea
Transocean Barents (b) (c)	HSS	2009	10,000	30,000	Idle
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 floaters.

Deepwater floaters (5)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Transocean Marianas (b)	HSS	1979/1998	7,000	30,000	Idle
Sedco 706 (c)	HSS	1976/2008	6,500	25,000	Brazil
Sedco 702 (c)	HSS	1973/2007	6,500	25,000	Nigeria
Jack Bates (b)	HSS	1986/1997	5,400	30,000	Australia
M.G. Hulme, Jr. (b)	HSS	1983/1996	5,000	25,000	Idle

“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) Moored floaters.
(c) Dynamically positioned.

Midwater floaters (11)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location

Transocean Driller	OS	1991	3,000	25,000	Brazil
GSF Rig 140	OS	1983	2,800	25,000	India
Sedco 711	OS	1982	1,800	25,000	Stacked
Transocean John Shaw	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	Idle
Transocean Prospect	OS	1983/1992	1,500	25,000	Stacked
Transocean Searcher	OS	1983/1988	1,500	25,000	Stacked
Transocean Winner	OS	1983	1,500	25,000	Norwegian N. Sea
Sedco 704	OS	1974/1993	1,000	25,000	U.K. N. Sea

"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
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 (b)	2012	400	30,000	Angola
GSF Constellation II	2004	400	30,000	Gabon
GSF Constellation I	2003	400	30,000	United Arab Emirates
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.
(b) Owned through our 70 percent interest in Transocean Drilling Services Offshore Inc. ("TDSOI").

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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 11, 2016, our drilling fleet was located in the U.K. North Sea (13 units), U.S. Gulf of Mexico (10 units), Trinidad (seven units), Norway (five units), Brazil (four units), Angola (three units), Thailand (three units), India (two units), Malaysia (two units), Nigeria (two units), Australia (one unit), Canada (one unit), Gabon (one unit), Ivory Coast (one unit), Myanmar (one unit), Romania (one unit), Singapore (one unit), South Africa (one unit), Spain (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 associated 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.

At present, the industry is experiencing a cyclical downturn. Sustained weak commodity pricing has resulted in our customers delaying investment decisions and postponing exploration and production programs. Oil and natural gas 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 seen a sharp decline in the execution of drilling contracts for the global offshore drilling fleet and an unprecedented level of early drilling contract terminations. We currently expect very few drilling contracts to be awarded in 2016, 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, 2015 and 2014, we sold 17 and two drilling units, respectively, for scrap value, and at December 31, 2015, we have five additional rigs 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 meet global demand for hydrocarbons replacing reserves. 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. Many of 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 exploration and production companies operating in deeper water depths or other challenging environments or with complex well designs.

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,		
	2015	2014	2013
Operating revenues			
U.S.	$ 1,891	$ 2,289	$ 2,382
U.K.	1,139	1,194	1,181
Norway	650	1,036	1,208
Other countries (a)	3,706	4,655	4,478
Total operating revenues	$ 7,386	$ 9,174	$ 9,249

(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.

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

	December 31, 2015	December 31, 2014
Long-lived assets		
U.S.	$ 7,452	$ 7,080
Korea	2,048	1,535
Other countries (a)	11,318	12,923
Total long-lived assets	$ 20,818	$ 21,538

(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, 2015, the contract backlog was approximately $16.0 billion, representing a decrease of 29 percent and 43 percent, respectively, compared to the contract backlog at December 31, 2014 and 2013, which was $22.5 billion and $28.2 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 with customers 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 their obligations 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."

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 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

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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 14—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, 2015, our most significant customers were Chevron Corporation (together with its affiliates, "Chevron") and Royal Dutch Shell plc (together with its affiliates, "Shell"), representing approximately 14 percent and 10 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, 2015. Additionally, as of February 11, 2016, the customers with the most significant aggregate amount of contract backlog associated with our drilling contracts were Shell and Chevron, representing approximately 51 percent and 21 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 financial results."

Employees

We require highly skilled personnel to operate our drilling units. Consequently, we conduct extensive personnel recruiting, training and safety programs. At December 31, 2015, we had approximately 9,100 employees associated with our continuing operations, including approximately 500 persons engaged through contract labor providers. Approximately 30 percent of our total workforce, working primarily in Angola, the U.K., Nigeria, Norway, Australia and Brazil 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.

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.

Joint Venture, Agency and Sponsorship Relationships and Other Investments

As of December 31, 2015, we held a 70.9 percent limited liability company interest in Transocean Partners. On August 5, 2014, we completed the initial public offering of 20.1 million common units of Transocean Partners, which trades on the NYSE under the ticker symbol "RIGP." During the year ended December 31, 2015, Transocean Partners repurchased 91,500 common units under its unit repurchase program, and at December 31, 2015, 20.0 million publicly traded common units remained outstanding. We hold the remaining 21.3 million common units and 27.6 million subordinated units of Transocean Partners and all of its incentive distribution rights.

Additionally, 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. Some of the joint ventures in which we participate are 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. Beginning January 31, 2016, Angco Cayman Limited will have 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 70 percent interest in TDSOI, a consolidated British Virgin Islands joint venture company formed to own Transocean Honor, which operates in Angola. Our local partner, Angco II, a Cayman Islands company, holds the remaining 30 percent interest in TDSOI. Under certain circumstances, Angco II will have 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 jackup, 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 and Nigeria that have been formed to perform certain management services and other onshore support services for our operations.

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Technological Innovation

We are a leading international provider of offshore contract drilling services for oil and gas wells. We specialize in technically demanding sectors of the global offshore drilling business. Our fleet is considered one of the most versatile in the world with a particular focus on deepwater and harsh environment drilling capabilities. 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. In recent years, we have repeatedly achieved the world water depth record, holding the current world record at 10,411 feet. Eighteen rigs in our existing fleet are, and six of our rigs that are currently 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 unique 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 will include industry leading hookload capability, compensated cranes for performing subsea installations, hybrid power systems and reduced emissions and advanced generator protection. The newbuild drillships will also be outfitted with two blowout preventers and triple liquid mud systems and are 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 expect to continue to develop technology internally, through partnerships, such as our collaboration with a customer to develop a fault resistant and fault tolerant blowout preventer control system, or to acquire technology through strategic acquisitions.

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 as part of our wider corporate responsibility effort. 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 U.S. Securities and Exchange Commission (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 section of 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 Eastern Europe 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 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 worsen. Since December 31, 2014, the price of crude oil as reported on the New York Mercantile Exchange has declined by approximately 50 percent. 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 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

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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. 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 six 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 over supplied 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.

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 year ended December 31, 2015, our customers early terminated or cancelled contracts for Discoverer Americas, Polar Pioneer, Sedco 714, Sedco Energy and Transocean Spitsbergen, and these rigs currently remain idle. Subsequent to December 31, 2015, we received notices of early termination or cancellation of drilling contracts for Deepwater Champion, Deepwater Millennium, Discoverer Deep Seas, GSF Constellation II, GSF Development Driller I and Transocean John Shaw. 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 11, 2016, the contract backlog associated with our continuing operations was approximately $15.5 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"). 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, in order to execute our growth plan, 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 statements of financial condition, results of operations and cash flows.

§ 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.

Certain credit rating agencies have recently downgraded the credit ratings of our non credit enhanced senior unsecured long term debt (“Debt Rating”). In February 2015, Moody’s Investors Service downgraded our Debt Rating to below investment grade and, in October 2015, further downgraded our Debt Rating, and recently announced that our Debt Rating is again under review for further downgrade. In March 2015, Standard & Poor’s downgraded our Debt Rating to below investment grade and recently further downgraded our Debt Rating with negative outlook. In October 2015, Fitch Ratings downgraded our Debt Rating to below investment grade and recently further downgraded our Debt Rating with negative outlook.

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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, and we may lose the ability to obtain future financing and suffer competitive disadvantages.

At December 31, 2015 and 2014, our overall debt level was approximately $8.5 billion and $10.1 billion, respectively. 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 unable to meet financial ratios or satisfy certain other conditions included in our bank credit agreements, which could result in our inability to meet requirements for borrowings under our bank credit agreements or a default under these agreements and trigger cross default provisions in our other debt instruments; 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.

§ 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 financial results.

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, 2015, our most significant customers were Chevron and Shell, accounting for approximately 14 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. As of February 11, 2016, the customers with the most significant aggregate amount of contract backlog associated with our drilling contracts were Shell and Chevron, representing approximately 51 percent and 21 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, financial condition and results of operations.

§ 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.

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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 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 as portions of the crew may be required to prepare rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. 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 11, 2016, we had six ultra deepwater floater and five high specification jackup newbuild rig projects. 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 result in delay in 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.

§ 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 14—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 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. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 14—Commitments and Contingencies—Macondo well incident commitments and contingencies—EPA Agreement."

§ 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.

New governmental safety and environmental requirements applicable to both deepwater and shallow water operations have been adopted for drilling in the U.S. Gulf of Mexico following the Macondo well incident. 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. We are unable to predict the impact that the continuing effects of the enhanced regulations will have on our operations.

§ 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. 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 (“GHGs”), 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

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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 foreign 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

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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 foreign 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 foreign 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 hurt 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 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.

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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 unless contractually required, 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 our 2015 annual general meeting our shareholders for the first time approved in a binding “say on pay” vote the compensation of members of our executive management and board of directors. At the 2016 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 2016 annual general meeting and the 2017 annual general meeting and (2) our executive management team for the year ending December 31, 2017. 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, such as our initial public offering of and investment in Transocean Partners LLC, 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:

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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.

§ We may be required to guarantee certain obligations or provide funding to Transocean Partners through a $300 million revolving credit facility between us and Transocean Partners which may impact our liquidity of ability to borrow the full amount of capacity under our existing credit facilities.

§ 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 level of our personnel as a result of any increased turnover and ongoing staff reduction initiatives, which could lead to higher downtime and

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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 30 percent of our total workforce, working primarily in Angola, the U.K., Nigeria, Norway, Australia and Brazil 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 foreign 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, commonly referred to as greenhouse gases ("GHGs") and including 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 GHG emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide.

Legislation to regulate emissions of GHGs has been introduced in the U.S. Congress. Some of the proposals would require industries to meet stringent new standards that may require substantial reductions in carbon emissions. Such reductions could be costly and difficult to implement. In addition, efforts have 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 the U.S., the EPA has undertaken efforts to regulate GHG emissions and has finalized motor vehicle GHG emissions standards, the effect of which could reduce demand for motor fuels refined from crude oil, and has also issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs commencing when

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the motor vehicle standards took effect on January 2, 2011. To the extent that our operations are subject to the EPA's GHG regulations, we may face increased capital and operating costs.

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 GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, 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 also subject to a number of significant tax disputes, including trials on civil charges that commenced in Norway in 2012. 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 have significant carrying amounts of long lived assets that are subject to impairment testing.
At December 31, 2015, the carrying amount of our property and equipment was $20.8 billion, representing 79 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, 2015, we recognized an aggregate loss of $1,175 million associated with the impairment of our deepwater floater and midwater floater asset groups. In the year ended December 31, 2014, we recognized a loss of $788 million associated with the impairment of our deepwater floater asset group. 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., 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. Additionally, members of the U.S. Congress have repeatedly introduced proposals which would disallow any deduction for otherwise tax deductible payments relating to any incident resulting in the discharge of oil into navigable waters, such as the Macondo well incident. 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.

In Switzerland, tax legislative proposals intending to abolish certain cantonal tax privileges to the extent such provisions treat Swiss and non Swiss income differently as well as implement other significant changes to existing tax laws and practices have been raised. These proposals are in response to certain guidance and demands from both the European Union and the Organization for Economic Co operation and Development (the “OECD”). These issues, plus other tax legislative matters, are expected to be considered by Switzerland during the next 12 months. 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.

In December 2013, the U.K. Treasury released draft proposals that would cap the amount a U.K. based contractor would be able to claim as a deductible expense for charter payments made to related companies. A ring fence was also proposed to ensure that the profits from activities in relation to the chartering of rigs from affiliates are not reduced by tax relief from any unconnected activities. On July 17, 2014, the U.K. legislation received Royal Assent with retroactive application effective as of April 2014. In December 2014, the U.K. Treasury released additional draft legislative proposals that would impose tax on certain aggressive tax planning techniques used by multinational entities to divert profits from the U.K. The draft legislation would tax companies that had structured its operations to avoid a permanent establishment in the U.K. and as a result of the structure the U.K. tax liability was reduced by 20 percent. The draft legislation would also apply to transactions lacking economic substance that occur between common controlled entities and the resulting transaction reduces the U.K. tax liability by 20 percent. The draft legislation would apply a 25 percent tax on companies that utilized theses aggressive techniques. The legislation became effective on April 1, 2015.

In December 2014, a special commission issued recommendations for significant tax reform in Norway. These recommendations included consideration of a decrease in the corporate income tax rate, as well as a cap on the tax deduction for charter payments made to related companies and a withholding tax on certain charter payments to related companies. 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.

Similarly, the OECD issued an action plan in July 2013 that called for member states to take action to prevent “base erosion and profit shifting” in situations where payments are made between affiliates from a jurisdiction with high tax rates to a jurisdiction with lower tax rates. A number of specific tax reform changes were proposed and publicly debated. In October 2015, the OECD issued its final package of measures. Some of these proposals may 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. 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 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.

§ 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 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 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

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15 percent tax rate on “qualified dividend income,” which applies to dividends paid to non corporate shareholders prior to 2011, 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.

Our ability to benefit from our deferred tax assets depends on us having sufficient future earnings to utilize our net operating loss carryforwards before they expire. We have established a valuation allowance against the future tax benefit for a number of our non U.S. net operating loss carryforwards, and we could be required to record an additional valuation allowance against our non U.S. or 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 carryforwards are subject to review and potential disallowance upon audit by the tax authorities of the jurisdictions where the net operating losses 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 2014 annual general meeting, our shareholders approved an authorized share capital, which will expire on May 16, 2016. Our current authorized share capital is limited to approximately six percent of our registered share capital. Unless our shareholders approve a new authorized share capital at our 2016 annual general meeting, we will generally need to obtain shareholder approval in the event we need to raise common equity 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. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. On May 24, 2013, we received approval from the Swiss authorities for the continuation of the share repurchase program for an additional three year repurchase period through May 23, 2016. Upon the delisting of our shares from the SIX becoming effective, which we expect to occur on March 31, 2016, the authorization of any new share repurchase program and the continuation of the share repurchase program approved at the 2009 annual general meeting will no longer be subject to approval requirements from Swiss authorities. 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 and other 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.

§ 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

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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 16, 2016, 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 45 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.

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Item 1B.Unresolved Staff Comments

None.

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; Cayman Islands and Luxembourg.

Our remaining offices and bases are located in various countries in North America, South America, Europe, Africa, the Middle East, India, the Far East and Australia. 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 14—Commitments and Contingencies" and "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Commitments and contingencies—Macondo well incident commitments and contingencies" in this annual report on Form 10 K for the year ended December 31, 2015. We are also involved in various tax matters as described in "Part II. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 6—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, 2015. All such actions, claims, tax and other matters are incorporated herein by reference.

As of December 31, 2015, 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 Petrobras 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, 2016, 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, 2016
Jeremy D. Thigpen (a)	President and Chief Executive Officer	41
Terry B. Bonno	Senior Vice President, Marketing	58
Howard E. Davis	Executive Vice President, Chief Administrative Officer and Chief Information Officer	57
Brady K. Long	Senior Vice President and General Counsel	43
Mark L. Mey (a)	Executive Vice President, Chief Financial Officer	52
John B. Stobart (a)	Executive Vice President, Chief Operating Officer	61
David Tonnel	Senior Vice President, Supply Chain and Corporate Controller	46

(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 board of directors of the Company. 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, Marketing, of the Company. Before being named to her current position in August 2011, Ms. Bonno served as 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 as Vice President - General Counsel and Secretary of Ensco plc since May 2011, when Ensco plc 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. Mr. Long previously practiced corporate and securities law for BJ Services Company and 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 served as Senior Vice President and Chief Financial Officer of Scorpion Offshore Ltd. from August 2005 to July 2010. Prior to 2005, he held various senior financial and other roles in the drilling and financial services industries, including 12 years with Noble Corporation. Mr. Mey 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, he 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

Markets for Shares of Our Common Equity

Our shares are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “RIG” and on the SIX Swiss Exchange (“SIX”) under the symbol “RIGN.” On November 23, 2015, we announced our intent to delist our shares from the SIX. On December 17, 2015, we announced that the SIX listing authorities approved our application to delist our shares, and such delisting is expected to become effective on March 31, 2016, with the last trading day scheduled to be March 30, 2016. The following table presents the intraday high and low per share sales prices as reported on the NYSE and the SIX for the periods indicated.

	NYSE Stock Price				SIX Stock Price			
	2015		2014		2015		2014	
	High	Low	High	Low	High	Low	High	Low
First quarter	$ 20.65	$ 13.28	$ 49.58	$ 38.47	CHF 18.88	CHF 11.83	CHF 44.72	CHF 33.30
Second quarter	21.90	14.44	46.12	39.41	19.50	13.85	41.31	34.62
Third quarter	16.20	11.26	45.21	31.76	15.42	10.55	40.18	30.47
Fourth quarter	17.19	11.95	32.41	15.97	17.00	11.91	31.04	15.32

On February 16, 2016, the last reported sales price of our shares on the NYSE and the SIX was $8.66 per share and CHF 8.57 per share, respectively. On such date, there were 6,557 holders of record of our shares and 364,113,962 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 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, shareholders approved the cancellation of the third and fourth installments of the distribution at our extraordinary general meeting.

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.

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 of $0.56 per outstanding share, subject to certain limitations. On June 19, September 18 and December 18, 2013, we paid the first three installments, in the aggregate amount of $606 million, to shareholders of record as of May 31, August 23 and November 15, 2013, respectively. 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 do 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."

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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 relation to a reduction of par value are exempt from Swiss withholding tax. Since January 1, 2011, distributions to shareholders out of qualifying additional paid in capital for Swiss statutory purposes are also exempt from the Swiss withholding tax. On December 31, 2015, the aggregate amount of par value of our outstanding shares was CHF 5.6 billion, equivalent to $5.6 billion, and the aggregate amount of qualifying additional paid in capital of our outstanding shares was CHF 8.9 billion, equivalent to $8.9 billion, at an exchange rate of $1.00 to CHF 1.00 on December 31, 2015. 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. The procedures for claiming treaty refunds, and the time frame required for obtaining a refund, may differ from country to country.

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.

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 needs to be filled out 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.

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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.

We expect the delisting of our shares on the SIX to become effective on March 31, 2016. Thereafter, 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 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.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (2) (in millions)
October 2015	1,502	$ 16	—	$ 3,253
November 2015	—	—	—	3,253
December 2015	255	13	—	3,253
Total	1,757	$ 16	—	$ 3,253

(a) Total number of shares purchased in the fourth quarter of 2015 consists of 1,757 shares withheld by us through a broker arrangement and limited to statutory tax in satisfaction of withholding taxes due upon the vesting of restricted shares granted to our employees under our Long Term Incentive Plan.

(b) In May 2009, at the annual general meeting of Transocean Ltd., 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, which is equivalent to approximately $3.5 billion at an exchange rate as of December 31, 2015 of USD 1.00 to CHF 1.00. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. On May 24, 2013, we received approval from the Swiss authorities for the continuation of the share repurchase program for an additional three year repurchase period through May 23, 2016. Upon the delisting of our shares from the SIX becoming effective, which we expect to occur on March 31, 2016, the authorization of any new share repurchase program and the continuation of the share repurchase program approved at the 2009 annual general meeting will no longer be subject to approval requirements from Swiss authorities. 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. Through December 31, 2015, we have repurchased a total of 2,863,267 of our shares under this share repurchase program at a total cost of $240 million, equivalent to an average cost of $83.74 per share. On October 29, 2015, shareholders at our extraordinary general meeting approved the cancellation of all shares that have been 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. See "—Sources and uses of liquidity."

Item 6.Selected Financial Data

The selected financial data as of December 31, 2015 and 2014 and for each of the three years in the period ended December 31, 2015 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, 2013, 2012 and 2011, and for each of the two years in the period ended December 31, 2012 have been derived from our accounting records. The following data should be read in conjunction with "Item 7. Management's

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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."

	Years ended December 31,				
	2015	2014 (a)	2013	2012	2011 (b)
	(In millions, except per share data)				
Statement of operations data					
Operating revenues	$ 7,386	$ 9,174	$ 9,249	$ 8,945	$ 7,598
Operating income (loss)	1,380	(1,378)	2,217	1,600	(4,802)
Income (loss) from continuing operations	824	(1,946)	1,398	832	(5,801)
Net income (loss)	826	(1,966)	1,407	(211)	(5,677)
Net income (loss) attributable to controlling interest	791	(1,913)	1,407	(219)	(5,754)
Per share earnings (loss) from continuing operations					
Basic	$ 2.16	$ (5.23)	$ 3.85	$ 2.32	$ (18.27)
Diluted	$ 2.16	$ (5.23)	$ 3.85	$ 2.32	$ (18.27)
Balance sheet data (at end of period)					
Total assets	$ 26,329	$ 28,571	$ 32,658	$ 34,368	$ 35,052
Debt due within one year	1,093	1,032	323	1,365	2,181
Long-term debt	7,397	9,019	10,329	11,035	11,300
Total equity	14,808	13,982	16,685	15,730	15,627
Other financial data					
Cash provided by operating activities	$ 3,445	$ 2,220	$ 1,918	$ 2,708	$ 1,825
Cash used in investing activities	(1,932)	(1,828)	(1,658)	(389)	(1,896)
Cash provided by (used in) financing activities	(1,809)	(1,000)	(2,151)	(1,202)	734
Capital expenditures	2,001	2,165	2,238	1,303	974
Distributions of qualifying additional paid-in capital	381	1,018	606	276	759
Per share distributions of qualifying additional paid-in capital	$ 0.30	$ 2.81	$ 1.68	$ 0.79	$ 2.37

(a) 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, to own, operate and acquire modern, technologically advanced offshore drilling rigs.

(b) In October 2011, we completed our acquisition of Aker Drilling ASA ("Aker Drilling") and applied the acquisition method of accounting for the business combination. The balance sheet data as of December 31, 2011 represents the consolidated statement of financial position of the combined company. The statement of operations and other financial data for the year ended December 31, 2011 include approximately three months of operating results and cash flows for the combined company.

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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 16, 2016, we owned or had partial ownership interests in and operated 61 mobile offshore drilling units, including 28 ultra deepwater floaters, seven harsh environment floaters, five deepwater floaters, 11 midwater floaters, and 10 high specification jackups. At February 16, 2016, we also had six 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.

On August 5, 2014, we completed an initial public offering to sell a noncontrolling interest in Transocean Partners LLC ("Transocean Partners"), a Marshall Islands limited liability company, which was formed on February 6, 2014, by Transocean Partners Holdings Limited, a Cayman Islands company and our wholly owned subsidiary, to own, operate and acquire modern, technologically advanced offshore drilling rigs. See Notes to Consolidated Financial Statements—Note 15—Noncontrolling Interest.

In February 2014, in connection with our efforts to discontinue non strategic operations, we completed the sale of Applied Drilling Technology International Limited ("ADTI"), a U.K. company, which performs drilling management services in the North Sea. See Notes to Consolidated Financial Statements—Note 7—Discontinued Operations.

Significant Events

Macondo well incident litigation and settlements and insurance recoveries—On May 20, 2015, we entered into a confidential settlement agreement with BP to settle various disputes remaining between the parties with respect to the Macondo well incident (the "BP Settlement Agreement"). On May 29, 2015, together with the Plaintiff's Steering Committee (the "PSC"), we filed a settlement agreement (the "PSC Settlement Agreement") with the U.S. District Court for the Eastern District of Louisiana (the "MDL Court") through which we have agreed to pay, subject to the MDL Court approval, a total of $212 million, plus up to $25 million for partial reimbursement of attorneys' fees. On 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. In the year ended December 31, 2015, in connection with such settlements, we recognized income of $788 million ($735 million, net of tax), recorded as a net reduction to operating and maintenance costs and expenses, including $538 million associated with recoveries from insurance for our previously incurred losses, $125 million associated with partial reimbursement from BP for our previously incurred legal costs, and $125 million associated with a net reduction to certain related contingent liabilities. In the year ended December 31, 2015, we received cash proceeds of $538 million associated with recoveries from insurance, we received cash proceeds of $125 million associated with the partial reimbursement from BP for previously incurred legal costs, we made a cash deposit of $212 million into an escrow account associated with the pending court approval of our settlement with the PSC and we made an aggregate cash payment of $35 million to the States. See “—Operating Results,” “—Liquidity and Capital Resources—Sources and uses of liquidity” and “—Contingencies and Uncertainties—Macondo well incident.”

Norway tax investigations and trial—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. See “—Contingencies and Uncertainties—Tax matters.”

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Debt redemption and repurchases—On July 30, 2015, we redeemed the aggregate principal amount of $893 million of the outstanding 4.95% Senior Notes with an aggregate cash payment of $904 million for the full redemption of the notes, and we recognized a loss of $10 million associated with the retirement of the debt. During the year ended December 31, 2015, we made an aggregate cash payment of $468 million and recognized an aggregate net gain of $33 million associated with the open market repurchases of an aggregate principal amount of $503 million of certain of our publicly traded debt securities. See "—Liquidity and Capital Resources—Sources and uses of liquidity".

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. 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, shareholders at our extraordinary general meeting approved the cancellation of the third and fourth installments of the dividend.

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. 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.

See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Impairments of long lived assets—During the year ended December 31, 2015, we identified indicators that our deepwater floater and midwater floater asset groups may not be recoverable. As a result of our impairment testing, in the year ended December 31, 2015, we recognized a loss of $1.2 billion ($1.1 billion, net of tax) associated with the impairment of these held and used assets. See "—Operating Results" and Notes to Consolidated Financial Statements—Note 5—Impairments.

In the year ended December 31, 2015, we recognized an aggregate loss of $692 million ($578 million, net of tax) associated with the impairment of the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Deepwater Navigator, Discoverer Seven Seas, GSF Celtic Sea, Sedco 707 and Transocean Rather and the midwater floaters GSF Aleutian Key, GSF Arctic III, GSF Grand Banks, GSF Rig 135, Transocean Amirante and Transocean Legend along with related equipment, which were classified as assets held for sale at the time of the impairment. See "—Operating Results", "—Liquidity and Capital Resources—Drilling fleet" and Notes to Consolidated Financial Statements—Note 5—Impairments.

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, 2015, we recognized revenues of $505 million and received aggregate cash proceeds of $400 million associated with early terminated or cancelled drilling contracts for Discoverer Americas, Polar Pioneer, Sedco 714, Sedco Energy and Transocean Spitsbergen. Subsequent to December 31, 2015, we received notices of early termination or cancellation of drilling contracts for Deepwater Champion, Deepwater Millennium, Discoverer Deep Seas, GSF Constellation II, GSF Development Driller I and Transocean John Shaw. See "—Outlook," "—Operating Results" and "—Liquidity and Capita

Resources—Sources and uses of cash."

Dispositions—During the year ended December 31, 2015, we completed the sale of the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Discoverer Seven Seas, GSF Celtic Sea, Sedco 707, Sedco 710, Sovereign Explorer and Transocean Rather and the midwater floaters C. Kirk Rhein, Jr., GSF Aleutian Key, GSF Arctic I, GSF Arctic III, J.W. McLean, Sedco 601, Sedco 700, Transocean Amirante and Transocean Legend along with related equipment, and we received net cash proceeds of $35 million. See "—Liquidity and Capital Resources—Drilling fleet."

Markets for our shares—Our shares are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "RIG" and on the SIX Swiss Exchange ("SIX") under the symbol "RIGN." On November 23, 2015, we announced our intent to delist our shares from the SIX. On December 17, 2015 we announced that the SIX listing authorities approved our application to delist our shares, and such delisting is expected to become effective on March 31, 2016, with the last trading day scheduled to be March 30, 2016. Our shares will continue to be listed and traded on the NYSE.

Par value reduction—On October 29, 2015, shareholders at our extraordinary general meeting 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. See Notes to Consolidated Financial Statements—Note 16—Shareholders' Equity and Note 25—Subsequent Events.

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Outlook

Drilling market—Although our long term view of the offshore drilling market remains positive, particularly for high specification assets, we expect the near to medium term to be especially challenging. The sustained weak commodity pricing, coupled with our customers' focus on reducing costs, spending within their cash flow and maintaining capital allocation policies are resulting in the delay of many exploration and development programs. Oil and natural gas 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 seen a sharp decline in the execution of drilling contracts for the global offshore drilling fleet and an increase in the early termination or cancellation of drilling contracts. We currently expect very few drilling contracts to be awarded in 2016, exacerbating the excess rig capacity and placing continued downward pressure on dayrates. 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. Then, subsequent to December 31, 2015, we received notices of early termination or cancellation of drilling contracts for Deepwater Champion, Deepwater Millennium, Discoverer Deep Seas, GSF Constellation II, GSF Development Driller I and Transocean John Shaw. 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, 2015 and 2014, we sold 17 and two drilling units, respectively, for scrap value, and at December 31, 2015, we had five additional rigs classified as held for sale for scrap value. As of February 11, 2016, our contract backlog was $15.5 billion compared to $16.9 billion as of October 26, 2015.

Fleet status—We present 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 11, 2016, uncommitted fleet rates for each of the five years in the period ending December 31, 2020 were as follows:

	2016		2017		2018		2019		2020	
Uncommitted fleet rate										
Ultra-deepwater floaters	52	%	63	%	72	%	77	%	82	%
Harsh environment floaters	64	%	70	%	86	%	92	%	100	%
Deepwater floaters	70	%	80	%	83	%	100	%	100	%
Midwater floaters	78	%	100	%	100	%	100	%	100	%
High-specification jackups	47	%	77	%	93	%	100	%	100	%

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:

Contract backlog	February 11, 2016	October 26, 2015	February 17, 2015
	(In millions)		
Ultra-deepwater floaters	$ 13,539	$ 14,444	$ 16,529
Harsh environment floaters	920	1,146	1,591
Deepwater floaters	320	222	673
Midwater floaters	261	530	1,613
High-specification jackups	467	595	834
Total contract backlog	$ 15,507	$ 16,937	$ 21,240

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

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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.

At February 11, 2016, the contract backlog and average contractual dayrates for our fleet were as follows:

		For the years ending December 31,				
	Total	2016	2017	2018	2019	Thereafter
Contract backlog	(In millions, except average dayrates)					
Ultra-deepwater floaters	$ 13,539	$ 2,294	$ 2,062	$ 1,700	$ 1,450	$ 6,033
Harsh environment floaters	920	385	340	152	43	—
Deepwater floaters	320	145	94	81	—	—
Midwater floaters	261	261	—	—	—	—
High-specification jackups	467	271	148	48	—	—
Total contract backlog	$ 15,507	$ 3,356	$ 2,644	$ 1,981	$ 1,493	$ 6,033
Average-contractual dayrates						
Ultra-deepwater floaters	$ 520,000	$ 508,000	$ 512,000	$ 527,000	$ 526,000	$ 525,000
Harsh environment floaters	$ 320,000	$ 346,000	$ 302,000	$ 306,000	$ 305,000	$ —
Deepwater floaters	$ 257,000	$ 248,000	$ 266,000	$ 266,000	$ —	$ —
Midwater floaters	$ 332,000	$ 332,000	$ —	$ —	$ —	$ —
High-specification jackups	$ 149,000	$ 151,000	$ 148,000	$ 140,000	$ —	$ —
Total fleet average	$ 455,000	$ 382,000	$ 406,000	$ 453,000	$ 515,000	$ 525,000

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.

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,		
	2015	2014	2013
Average daily revenue			
Ultra-deepwater floaters	$ 513,900	$ 538,400	$ 500,200
Harsh environment floaters	$ 542,600	$ 470,500	$ 451,700
Deepwater floaters	$ 354,400	$ 378,300	$ 353,300
Midwater floaters	$ 349,200	$ 347,200	$ 311,100
High-specification jackups	$ 172,900	$ 168,500	$ 164,400
Total fleet average daily revenue	$ 400,500	$ 408,200	$ 382,300

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.

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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,					
	2015		2014		2013	
Revenue efficiency						
Ultra-deepwater floaters	95	%	94	%	89	%
Harsh environment floaters	98	%	96	%	97	%
Deepwater floaters	97	%	96	%	91	%
Midwater floaters	95	%	93	%	94	%
High-specification jackups	99	%	97	%	98	%
Total fleet average revenue efficiency	96	%	95	%	92	%

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,					
	2015		2014		2013	
Rig utilization						
Ultra-deepwater floaters	65	%	82	%	92	%
Harsh environment floaters	64	%	91	%	100	%
Deepwater floaters	73	%	62	%	68	%
Midwater floaters	77	%	64	%	61	%
High-specification jackups	83	%	93	%	91	%
Total fleet average rig utilization	71	%	76	%	79	%

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.

For the year ended December 31, 2015, our rig utilization for deepwater floaters and midwater floaters increased as a result of removing stacked and idled rigs from our drilling fleet.

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Operating Results

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

The following is an analysis of our operating results. 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	$ 8,952	$ (2,150)	(24) %
Other revenues	584	222	362	n/m
	7,386	9,174	(1,788)	(19) %
Operating and maintenance expense	(2,955)	(5,110)	2,155	42 %
Depreciation expense	(963)	(1,139)	176	15 %
General and administrative expense	(193)	(234)	41	18 %
Loss on impairment	(1,867)	(4,043)	2,176	54 %
Loss on disposal of assets, net	(28)	(26)	(2)	(8) %
Operating income (loss)	1,380	(1,378)	2,758	n/m
Other income (expense), net				
Interest income	22	39	(17)	(44) %
Interest expense, net of amounts capitalized	(432)	(483)	51	11 %
Other, net	60	22	38	n/m
Income (loss) from continuing operations before income tax expense	1,030	(1,800)	2,830	n/m
Income tax expense	(206)	(146)	(60)	(41) %
Income (loss) from continuing operations	$ 824	$ (1,946)	$ 2,770	n/m

"n/m" 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 for early termination or cancellation fees.

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, 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 two newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2014 and (c) approximately $35 million of increased depreciation resulting from our completion of other construction projects.

General and administrative expense decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to due to the following: (a) approximately $21 million of reduced personnel costs and (b) approximately $13 million of reduced legal and professional fees.

Losses on impairments and disposals—In the year ended December 31, 2015, we recognized a loss on impairment related to the following: (a) a loss of $507 million associated with the impairment of our deepwater floater asset group, (b) a loss of $668 million associated with the impairment of our midwater floater asset group and (c) an aggregate loss of $692 million associated with the impairment of certain assets classified as held for sale. 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.

In the year ended December 31, 2015, we recognized an aggregate net gain of $14 million associated with the sale of two ultra deepwater floaters, six deepwater floaters and nine midwater floaters, along with related equipment. In the year ended December 31, 2014, we recognized an aggregate net loss of $1 million associated with the sale of a deepwater floater, a midwater floater and two high specification jackups along with related equipment. In the years ended December 31, 2015 and 2014, we recognized an aggregate net loss of $42 million and $25 million, respectively, associated with the disposal of assets unrelated to rig sales.

Other income and expense—In the year ended December 31, 2015, we recognized other income, net, primarily related to the following: (a) a gain of $35 million associated with income from license fees and royalties for our dual activity patent and (b) a gain of $23 million associated with the early retirement of debt, including the redemption of the 4.95% Senior Notes due November 2015 (the “4.95% Senior Notes”) and repurchases of other public debt in the open market. In the year ended December 31, 2014, we recognized other income, net primarily related to the following: (a) a gain of $18 million associated with currency exchange, (b) a gain of $7 million associated with the prepayment of certain notes receivable, (c) a gain of $7 million associated with settlement of litigation related to our dual activity patent, partially offset by (d) an aggregate loss of $13 million associated with the early retirement of debt, including the partial redemption of the 4.95% Senior Notes and the termination of our former three year secured revolving credit facility.

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, the annual effective tax rates were 16.4 percent and 18.7 percent, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as losses on impairment, and gains and losses on certain asset disposals. During the year ended December 31, 2015, our annual effective tax rate decreased due to changes in the relative blend of income from operations among certain jurisdictions and changes in the jurisdictional and operating structure for certain rigs, which had an effect on our deferred tax assets. This decrease was partially offset by an increase from changes in currency exchange rates. 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. For the year ended December 31, 2015 and 2014, the effect of the various discrete period tax items was a net tax benefit of $35 million and $138 million, respectively. For the year ended December 31, 2015 and 2014, these discrete tax items, coupled with the excluded income and expense items noted above, resulted in effective tax rates of 20.0 percent and (8.1) 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 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. 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 annual 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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Year ended December 31, 2014 compared to the year ended December 31, 2013

The following is an analysis of our operating results. See "—Performance and Other Key Indicators" for definitions of operating days, average daily revenue, revenue efficiency and rig utilization.

	Years ended December 31,			
	2014	2013	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	21,893	23,687	(1,794)	(8) %
Average daily revenue	$ 408,200	$ 382,300	$ 25,900	7 %
Revenue efficiency	95 %	92 %		
Rig utilization	76 %	79 %		
Contract drilling revenues	$ 8,952	$ 9,070	$ (118)	(1) %
Other revenues	222	179	43	24 %
	9,174	9,249	(75)	(1) %
Operating and maintenance expense	(5,110)	(5,563)	453	8 %
Depreciation expense	(1,139)	(1,109)	(30)	(3) %
General and administrative expense	(234)	(286)	52	18 %
Loss on impairment	(4,043)	(81)	(3,962)	n/m
Gain (loss) on disposal of assets, net	(26)	7	(33)	n/m
Operating income (loss)	(1,378)	2,217	(3,595)	n/m
Other income (expense), net				
Interest income	39	52	(13)	(25) %
Interest expense, net of amounts capitalized	(483)	(584)	101	17 %
Other, net	22	(29)	51	n/m
Income (loss) from continuing operations before income tax expense	(1,800)	1,656	(3,456)	n/m
Income tax expense	(146)	(258)	112	43 %
Income (loss) from continuing operations	$ (1,946)	$ 1,398	$ (3,344)	n/m

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the following: (a) approximately $500 million of decreased revenues resulting from a greater number of idle rigs, (b) approximately $245 million of decreased revenues resulting from rigs that were sold or classified as held for sale and (c) approximately $210 million of decreased revenues resulting from increased time dedicated to mobilization between contracts, shipyard projects and rig certifications. These decreases were partially offset by the following: (a) approximately $290 million of increased revenues resulting from improved dayrates, (b) approximately $285 million of increased revenues resulting from improved revenue efficiency and (c) approximately $265 million of increased revenues associated with our three newbuild high specification jackups that commenced operations during the year ended December 31, 2013 and our two newbuild ultra deepwater drillships that commenced operations in the year ended December 31, 2014.

Other revenues increased for the year ended December 31, 2014 compared to the year ended December 31, 2013, primarily due to increased revenues associated with reimbursable items.

Costs and expenses—Operating and maintenance expense decreased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the following: (a) approximately $195 million of decreased costs and expenses due to rigs that were sold or classified as held for sale in the year ended December 31, 2014, (b) approximately $190 million of decreased costs and expenses, net of insurance recoveries, associated with the Macondo well incident and (c) approximately $130 million of decreased costs and expenses associated with stacked and idle rigs. These decreases were partially offset by approximately $70 million of increased costs and expenses due to our newbuild rigs placed in service.

General and administrative expense decreased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to due to the following: (a) $24 million of decreased personnel costs primarily associated with reduced wages and salaries, and (b) $21 million of decreased legal and professional fees, primarily related to litigation and the 2013 proxy campaign.

Losses on impairments and disposals—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 the deepwater floater asset group and (c) an aggregate loss of $268 million associated with the impairment of certain assets classified as held for sale. In the year ended December 31, 2013, we recognized an aggregate loss of $64 million associated with the impairment of certain assets classified as held for sale and a loss of $17 million associated with the impairment of certain corporate assets.

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In the year ended December 31, 2014, we recognized an aggregate net loss of $1 million associated with the sale of a deepwater floater, a midwater floater and two high specification jackups along with related equipment. In the year ended December 31, 2013, we recognized a net gain of $33 million associated with the sale of a deepwater floater along with related equipment. In the years ended December 31, 2014 and 2013, we recognized an aggregate net loss of $25 million and $26 million, respectively, associated with the disposal of assets unrelated to rig sales.

Other income and expense—Interest expense, net of amounts capitalized, decreased in the year ended December 31, 2014 compared to the year ended December 31, 2013, primarily due to approximately $55 million of increased interest capitalization associated with our newbuild construction program and $34 million of decreased interest expense associated with debt repaid in the year ended December 31, 2014.

In the year ended December 31, 2014, we recognized other income, net, primarily related to the following: (a) a gain of $18 million associated with currency exchange, (b) a gain of $7 million associated with the prepayment of certain notes receivable and (c) a gain of $7 million associated with settlement of litigation related to our dual activity patent, partially offset by (d) an aggregate loss of $13 million associated with the early retirement of debt, including the partial redemption of the 4.95% Senior Notes and the early termination of our former three year secured revolving credit facility. In the year ended December 31, 2013, we recognized other expense, net, primarily related to the following: (a) a loss of $11 million associated with currency exchange, (b) a loss of $10 million associated with the sale of an investment in preference shares and (c) a loss of $9 million associated with the early termination of interest rate swaps designated as a cash flow hedge of borrowings under a former credit facility.

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, 2014 and 2013, our annual effective tax rates were 18.7 percent and 20.1 percent, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as expenses for litigation matters, losses on impairment, and gains and losses on certain asset disposals. 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 are all treated as discrete period tax expenses or benefits. For the years ended December 31, 2014 and 2013, the effect of the various discrete period tax items was a net tax benefit of $138 million and $82 million, respectively. For the years ended December 31, 2014 and 2013, these discrete tax items, together with the excluded income and expense items noted above, resulted in effective tax rates of (8.1) percent and 15.6 percent, respectively, based on income from continuing operations before income tax expense, including these discrete tax items, together with the excluded income and expense items noted above.

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 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. 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. In the year ended December 31, 2014 compared to the year ended December 31, 2013, the annual effective tax rate decreased to 18.7 percent from 20.1 percent primarily due to changes in the blend of income that is taxed based on gross revenues versus income before taxes, the effect of higher income before income taxes offset by the impact of new U.K. legislation and the currency exchange effect of the weakened Norwegian krone relative to the U.S. dollar. With respect to the annual effective tax rate calculation for the year ended December 31, 2014, 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, Australia 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, 2015, we had $2.3 billion in cash and cash equivalents. At any given time, we may require a significant portion of our cash and cash equivalents for working capital and other needs related to the operation of our business. At December 31, 2015, we estimate the amount of cash required for these purposes, which is not generally available to us for other uses, was approximately $1.3 billion. We expect to reduce this required amount to approximately $800 million as an outcome of our ongoing organizational efficiency initiatives and in the event our industry stabilizes.

In the year ended December 31, 2015, 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 and proceeds from insurance recoveries and litigation settlements; net proceeds from restricted cash investments and proceeds from asset disposals. Our primary uses of cash were capital expenditures, primarily associated with our newbuild construction projects; repayments of debt; payments of installments to our shareholders for distributions of qualifying paid in capital and payment of our Macondo well incident settlement obligations.

	Years ended December 31,		
	2015	2014	Change
	(In millions)		
Cash flows from operating activities			
Net income (loss)	$ 826	$ (1,966)	$ 2,792
Depreciation	963	1,139	(176)
Loss on impairment	1,867	4,043	(2,176)
Loss on disposal of assets, net	27	36	(9)
Other non-cash items, net	126	51	75
Changes in Macondo well incident assets and liabilities, net	(426)	(498)	72
Changes in other operating assets and liabilities, net	62	(585)	647
	$ 3,445	$ 2,220	$ 1,225

Net cash provided by operating activities increased primarily due to cash proceeds of $400 million from customers that executed early terminations or cancellations of drilling contracts and other changes in working capital, including (a) an increase of $639 million associated with cash proceeds from insurance recoveries related to the Macondo well incident and (b) a decrease of $208 million associated with cash payments of scheduled installments for our Macondo well incident settlement obligations. Partially offsetting these items was a cash deposit of $212 million into an escrow account pending court approval of our settlement with the PSC with no comparable activity in the prior year.

	Years ended December 31,		
	2015	2014	Change
	(In millions)		
Cash flows from investing activities			
Capital expenditures	$ (2,001)	$ (2,165)	$ 164

Proceeds from disposal of assets, net	54	250	(196)
Proceeds from repayment of notes receivable	15	101	(86)
Other, net	—	(14)	14
	$ (1,932)	$ (1,828)	$ (104)

Net cash used in investing activities increased primarily due to a reduction of proceeds from disposal of assets and from repayment of loans and notes receivable. Partially offsetting the increased use of cash was a decrease in capital expenditures associated with the timing of milestone payments for our major construction projects and other shipyard projects.

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	Years ended December 31, 2015	2014	Change
	(In millions)		
Cash flows from financing activities			
Repayments of debt	$ (1,506)	$ (539)	$ (967)
Proceeds from restricted cash investments, net	110	156	(46)
Distributions of qualifying additional paid-in capital	(381)	(1,018)	637
Proceeds from sale of noncontrolling interest	—	443	(443)
Other, net	(32)	(42)	10
	$ (1,809)	$ (1,000)	$ (809)

Net cash used in financing activities increased primarily due to (a) increased cash used to redeem or repurchase debt and (b) cash proceeds from the sale of noncontrolling interest in Transocean Partners with no comparable activity in the year ended December 31, 2015. Partially offsetting these items was a reduction in cash used to pay installments to our shareholders for distributions of qualifying additional paid in capital.

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.

In the years ended December 31, 2015 and 2014, we made capital expenditures and other capital additions, such as capitalized interest, of $2.0 billion and $2.2 billion, respectively, including $1.6 billion and $1.4 billion, respectively, for our major construction projects. For the year ending December 31, 2016, we expect total capital expenditures and other capital additions, such as capitalized interest, to be approximately $1.4 billion, including approximately $1.3 billion for our major construction projects.

As of December 31, 2015, 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, 2015	For the years ending December 31, 2016	2017	2018	2019	2020	Total
	(In millions)						
Deepwater Thalassa (a)	$ 861	$ 59	$ —	$ —	$ —	$ —	$ 920
Deepwater Proteus (b)	765	75	—	—	—	—	840
Deepwater Conqueror (c)	372	478	—	—	—	—	850
Deepwater Pontus (d)	459	333	83	—	—	—	875
Deepwater Poseidon (d)	450	322	74	39	—	—	885
Transocean Cassiopeia (e)	54	6	15	195	—	—	270
Transocean Centaurus (e)	53	5	9	203	—	—	270

Transocean Cepheus (e)	53	5	9	14	194	—	275
Ultra-Deepwater drillship TBN1 (f)	204	19	60	50	467	—	800
Transocean Cetus (e)	52	5	8	10	205	—	280
Transocean Circinus (e)	51	5	9	9	19	197	290
Ultra-Deepwater drillship TBN2 (f)	157	15	61	27	72	458	790
Total	$ 3,531	$ 1,327	$ 328	$ 547	$ 957	$ 655	$ 7,345

(a) The ultra deepwater floater Deepwater Thalassa commenced operations in February 2016.

(b) Deepwater Proteus, a newbuild ultra deepwater drillship, was delivered from the shipyard and is expected to commence operations in the second quarter of 2016 following completion of mobilization, sea trials, operational readiness testing and customer acceptance.

(c) Deepwater Conqueror, a newbuild ultra deepwater drillship under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, is expected to commence operations in the fourth quarter of 2016.

(d) 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.

(e) 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 2018, the third quarter of 2018, the first quarter of 2019, the third quarter of 2019 and the first quarter of 2020, respectively.

(f) 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 second quarter of 2019 and the first quarter of 2020, respectively.

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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 new 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, as described below, 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 year ended December 31, 2015, we identified 22 such drilling units that we intend to sell or have sold for scrap value, including the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Deepwater Navigator, Discoverer Seven Seas, GSF Celtic Sea, Sedco 707, Sedco 710, Sovereign Explorer and Transocean Rather and the midwater floaters C. Kirk Rhein, Jr., Falcon 100, GSF Aleutian Key, GSF Arctic I, GSF Arctic III, GSF Grand Banks, GSF Rig 135, J.W. McLean, Sedco 601, Sedco 700, Sedneth 701, Transocean Amirante and Transocean Legend. 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, 2015, in connection with our efforts to dispose of non strategic assets, we completed the sale of the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Discoverer Seven Seas, GSF Celtic Sea, Sedco 707, Sedco 710, Sovereign Explorer and Transocean Rather and the midwater floaters C. Kirk Rhein, Jr., GSF Aleutian Key, GSF Arctic I, GSF Arctic III, J.W. McLean, Sedco 601, Sedco 700, Transocean Amirante and Transocean Legend 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 the deepwater floater Sedco 709, the midwater floater Sedco 703 and the high specification jackups GSF Magellan and GSF Monitor, along with related equipment, and we received aggregate net cash proceeds of $185 million.

Sources and uses of liquidity

Overview—We expect to use existing cash balances, internally generated cash flows, borrowings under our bank credit agreements, proceeds from the disposal of assets or proceeds from the issuance of debt to fulfill anticipated obligations, such as capital expenditures, scheduled debt maturities or other payments, repayment of debt due within one year, payments of our Macondo well incident settlement obligations, working capital and other needs in our operations. We may also consider establishing additional credit facilities under bank credit agreements, using proceeds from additional issuances of debt, or using proceeds from any sale of additional noncontrolling interests in or the issuance of debt of Transocean Partners. However, current market conditions may make any such transaction challenging. 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.

At any given time, we may require a significant portion of our cash on hand for working capital and other needs related to the operation of our business. We currently estimate this amount to be approximately $1.3 billion. We expect to reduce this required amount to approximately $800 million as an outcome of our ongoing organizational efficiency initiatives and in the event our industry stabilizes. As a result, this portion of cash is not generally available to us for other uses. From time to time, we may also use borrowings under our bank credit agreement to maintain liquidity for short term cash needs.

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, and subsequent to December 31, 2015, one of the credit rating agencies further downgraded our Debt Rating and another rating agency placed us on review for further downgrade. Such downgrades have caused, and any further downgrades may cause, us to experience increased fees under our credit facility and interest rates under agreements governing certain of our senior notes and may limit our ability to access debt markets. 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.

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,

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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 May 29, and August 25, 2015. On October 29, 2015, shareholders at our extraordinary general meeting 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 do 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 to settle various disputes remaining between the parties with respect to the Macondo well incident. Pursuant to the terms of the agreement, among other things, BP made 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 recognized income of $538 million, recorded as a reduction of operating and maintenance costs and expenses, associated with insurance proceeds for recovery of previously incurred losses.

On May 29, 2015, together with the PSC, we filed a 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. This PSC settlement is subject to approval by the MDL Court and acceptance by a minimum number of plaintiffs. In August 2015, we made a cash deposit of $212 million into an escrow account pending approval of the settlement by the MDL Court.

Effective October 13, 2015, we finalized a settlement agreement with 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 the years ended December 31, 2015 and 2014, we made an aggregate cash payment of $60 million in each year. On February 12, 2016, we made an aggregate cash payment of $60 million. At February 16, 2016, the remaining balance of our Plea Agreement obligations was $60 million, which is due on or before February 14, 2017.

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 paid the final two installments of $204 million and $412 million, respectively, including interest.

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 trade 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 hold 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. We may consider selling additional noncontrolling interests in or debt securities of Transocean Partners to provide additional sources of liquidity, although current market conditions may make such offerings challenging.

In February 2016, Transocean Partners declared and paid an aggregate distribution of $25 million, of which $7 million was paid to holders of noncontrolling interest and $18 million was paid to us and was eliminated in consolidation. 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 and $71 million was paid to us and was eliminated in consolidation. 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 and $11 million was paid to us and was eliminated in consolidation.

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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. Subject to market conditions, Transocean Partners may repurchase units from time to time in the open market or in privately negotiated transactions. It may suspend or discontinue the program at any time. The common units repurchased under the program will be cancelled. As of February 16, 2016, Transocean Partners had repurchased 306,967 of its publicly held common units for an aggregate purchase price of $3 million. At February 16, 2016, we held a 71.1 percent limited liability company interest in Transocean Partners.

Debt redemptions and repurchases—In September 2010, we issued $1.1 billion aggregate principal amount of 4.95% Senior Notes. On November 17, 2014, we made an aggregate cash payment of $216 million to redeem an aggregate principal amount of $207 million of the outstanding 4.95% Senior Notes. On July 30, 2015, we made an aggregate cash payment of $904 million to redeem the remaining aggregate principal amount of $893 million of the 4.95% Senior Notes. In the year ended December 31, 2015, we also made an aggregate cash payment of $468 million for open market repurchases of an aggregate principal amount of $503 million of certain of our publicly traded debt securities.

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, 2015, 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 depending on our Debt Rating. At February 16, 2016, based on our Debt Rating on that date, the Five Year Revolving Credit Facility Margin was 1.75 percent and the facility fee was 0.275 percent. At February 16, 2016, 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.

Eksportfinans Loans—We have outstanding borrowings under the Loan Agreement dated September 12, 2008 ("Eksportfinans Loan A") and outstanding borrowings under the Loan Agreement dated November 18, 2008 ("Eksportfinans Loan B," and together with Eksportfinans Loan A, the "Eksportfinans Loans"), between one of our subsidiaries and Eksportfinans ASA, which were established to finance the construction and delivery of the harsh environment ultra deepwater semisubmersibles Transocean Spitsbergen and Transocean Barents. Eksportfinans

Loan A and Eksportfinans Loan B bear interest at a fixed rate of 4.15 percent and require semi annual installments of principal and interest through September 2017 and January 2018, respectively. At February 16, 2016, aggregate borrowings of approximately $196 million were outstanding under Eksportfinans Loan A and Eksportfinans Loan B.

The Eksportfinans Loans require restricted cash investments to be held at a certain financial institution through expiration (the "Eksportfinans Restricted Cash Investments"). The Eksportfinans Restricted Cash Investments bear interest at a fixed rate of 4.15 percent with semi annual installments that correspond with those of the Eksportfinans Loans. At February 16, 2016, the aggregate principal amount of the Eksportfinans Restricted Cash Investments was $196 million.

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, which is equivalent to approximately $3.5 billion at an exchange rate as of the close of trading on February 16, 2016 of $1.00 to CHF 0.99. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. We intend to fund any repurchases using available cash balances and cash from operating activities. On May 24, 2013, we received approval from the Swiss authorities for the continuation of the share repurchase program for an additional three year repurchase period through May 23, 2016. Upon the delisting of our shares from the SIX becoming effective, which we expect to occur on March 31, 2016, the authorization of any new share repurchase program and the continuation of the share repurchase program approved at the 2009 annual general meeting will no longer be subject to approval requirements from the Swiss authorities. In the year ended December 31, 2015, we did not purchase shares under our share repurchase program.

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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 ratings 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 will be made from time to time based upon these factors.

Any shares repurchased under this program are expected to be purchased from time to time, from market participants that have acquired those shares on the open market and that can fully recover Swiss withholding tax resulting from the share repurchase. Repurchases could also be made by tender offer, in privately negotiated transactions or by any other share repurchase method. The share repurchase program could be suspended or discontinued by our board of directors or company management, as applicable, at any time. Any repurchased shares would be held by us for cancellation by the shareholders at a future general meeting of shareholders. On October 29, 2015, shareholders at our extraordinary general meeting approved the cancellation of all shares that have been repurchased to date under our share repurchase program. The shares repurchased under our share repurchase program were cancelled as of January 7, 2016 upon registration of the cancellation in the commercial register.

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 16, 2016, Transocean Inc., our wholly owned subsidiary, held as treasury shares approximately two percent of our issued shares. At the annual general meeting in May 2009, the shareholders approved the release of CHF 3.5 billion of additional paid in capital to other reserves, or freely available reserves as presented on our Swiss statutory balance sheet, to create the freely available reserve necessary for the CHF 3.5 billion share repurchase program for the purpose of the cancellation of shares (the "Currently Approved Program"). At the May 2011 annual general meeting, our shareholders approved the reallocation of CHF 3.2 billion, which is the remaining amount authorized under the share repurchase program, from free reserve to legal reserve, reserve from capital contributions. This amount will continue to be available for Swiss federal withholding tax free share repurchases. We may only repurchase shares to the extent freely distributable reserves are available. 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 eight 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.

Contractual obligations—At December 31, 2015, our contractual obligations stated at face value, were as follows:

		For the years ending December 31,			
	Total	2016	2017 - 2018	2019 - 2020	Thereafter
	(in millions)				
Contractual obligations					
Debt	$ 7,918	$ 1,063	$ 1,724	$ 900	$ 4,231

Interest on debt	4,452	489	784	677	2,502
Capital lease obligation (a)	974	71	143	144	616
Plea Agreement obligations	120	60	60	—	—
Operating lease obligations	121	15	25	19	62
Purchase obligations	2,964	968	608	1,388	—
Total (b)	$ 16,549	$ 2,666	$ 3,344	$ 3,128	$ 7,411

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

(b) As of December 31, 2015, our defined benefit pension and other postretirement plans represented an aggregate liability of $407 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 13—Postemployment Benefit Plans.

As of December 31, 2015, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of $405 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 6—Income Taxes.

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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 a number of committed and uncommitted bank credit facilities. The obligations that are the subject of these standby letters of credit and surety bonds are primarily geographically concentrated in Nigeria and 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, 2015, these obligations stated in U.S. dollar equivalents and their time to expiration were as follows:

	For the years ended December 31,				
	Total	2016	2017 - 2018	2019 - 2020	Thereafter
	(in millions)				
Other commercial commitments					
Standby letters of credit	$ 153	$ 114	$ 39	$ —	$ —
Surety bonds	30	6	24	—	—
Total	$ 183	$ 120	$ 63	$ —	$ —

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, 2015, the cash investments held by the captive insurance company totaled $192 million, and the amount of such cash investments is expected to range from $100 million to $225 million by December 31, 2016. 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.

Derivative instruments

Our board of directors has approved policies and procedures for derivative instruments that require the approval of our Chief Financial Officer prior to entering into any derivative instruments. From time to time, we may enter into a variety of derivative instruments in connection with the management of our exposure to fluctuations in interest rates or currency exchange rates. We do not enter into derivative transactions for speculative purposes; however, we may enter into certain transactions that do not meet the criteria for hedge accounting. See Notes to Consolidated Financial Statements—Note 12—Derivatives and Hedging and Note 25—Subsequent Events.

Pension Plans and Other Postretirement Benefit Plans

Overview—In connection with actions taken by us prior to December 31, 2015, benefits under all of our remaining U.S. defined benefit pension plans had ceased accruing or were scheduled to cease accruing by March 31, 2016. We will continue to maintain the respective pension obligations under such plans until they have been fully satisfied. As of December 31, 2015, we maintained one funded qualified benefit plan, which primarily covers employees on the U.S. payroll that work outside of the U.S., that will cease to accrue benefits, effective March 31, 2016. Effective January 1, 2015, we formalized amendments to cease accruing benefits under our funded qualified defined benefit pension plan, which previously covered substantially all of our U.S. employees, and a supplemental benefit plan, which previously provided certain eligible employees with benefits in excess of those allowed under the funded qualified defined benefit plan. We also maintain one funded and two unfunded defined benefit plans that had previously ceased accruing benefits. We refer to these plans, collectively, as the “U.S. Plans.”

As of December 31, 2015, we maintain a defined benefit plan in the U.K. (the “U.K. Plan”), which covers certain current and former employees in the U.K. In January 2016, we and the plan trustees mutually agreed to cease accruing benefits under the U.K. Plan, effective March 31, 2016. We also maintain six 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”). Additionally, we maintain certain unfunded defined benefit plans that provide retirement and severance benefits for certain eligible Nigerian and Indonesian employees. We also previously maintained an end of service benefit plan for certain of our Egyptian employees, for which we satisfied all obligations in the year ended December 31, 2015. We refer to the U.K. Plan, the Norway Plans and the plans in Nigeria, Indonesia and Egypt, 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 have several unfunded contributory and noncontributory other postretirement employee benefit plans (the “OPEB Plans”) covering substantially all of our U.S. employees. On August 25, 2015, we announced amendments to our OPEB Plans that provide for declining benefits to eligible participants during a phase out period ending December 31, 2025.

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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, 2015				Year ended December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Net periodic benefit costs (a)	$ (3)	$ 30	$ (1)	$ 26	$ 37	$ 36	$ 2	$ 75
Other comprehensive income (loss) (b)	(20)	80	29	89	(63)	(85)	(5)	(153)
Employer contributions	13	21	5	39	43	56	2	101
At end of period:								
Accumulated benefit obligation	$ 1,523	$ 458	$ 24	$ 2,005	$ 1,588	$ 553	$ 59	$ 2,200
Projected benefit obligation	1,523	502	24	2,049	1,592	629	59	2,280
Fair value of plan assets	1,198	439	—	1,637	1,271	488	—	1,759
Funded status	(325)	(63)	(24)	(412)	(321)	(141)	(59)	(521)
Accumulated comprehensive income (loss) (b)	(281)	(119)	25	(375)	(261)	(199)	(4)	(464)
Weighted-Average Assumptions								
-Net periodic benefit costs								
Discount rate (c)	4.16 %	3.26 %	3.86 %	3.95 %	5.04 %	4.41 %	4.54 %	4.85 %
Long-term rate of return (d)	7.79 %	5.93 %	n/a	7.33 %	7.18 %	6.07 %	n/a	6.88 %
Compensation trend rate (c)	0.21 %	3.83 %	n/a	1.04 %	4.13 %	4.25 %	n/a	4.16 %
Health care cost trend rate-initial	n/a	n/a	7.81 %	7.81 %	n/a	n/a	7.81 %	7.81 %
Health care cost trend rate-ultimate (e)	n/a	n/a	5.00 %	5.00 %	n/a	n/a	5.00 %	5.00 %
-Benefit obligations								
Discount rate (c)	4.55 %	3.59 %	3.13 %	4.30 %	4.15 %	3.13 %	3.86 %	3.86 %
Compensation trend rate (c)	3.82 %	3.77 %	n/a	3.79 %	3.82 %	3.72 %	n/a	3.74 %

“n/a” means not applicable.

(a) In the years ended December 31, 2015 and 2014, net periodic benefit costs were reduced by expected returns of $115 million and $103 million, respectively, from plan assets.
(b) Amounts presented before tax.
(c) Weighted average based on relative average projected benefit obligation for the year.
(d) Weighted average based on relative average fair value of plan assets for the year.
(e) Ultimate health care trend rate is expected to be reached in 2023.

Net periodic benefit cost—In the year ended December 31, 2015, net periodic benefit costs decreased $49 million and, in the year ending December 31, 2016, we expect net periodic benefit costs to decrease by approximately $25 million, primarily as a result of our decision to cease accruing benefits under the U.S. Plans.

Plan assets—We review our investment policies at least annually and our plan assets and asset allocations at least quarterly to evaluate performance relative to specified objectives. In determining our asset allocation strategies for the U.S. Plans, we review results of regression models to assess the most appropriate target allocation for each plan, given the plan's status, demographics, and duration. For the U.K. Plan, the plan trustees establish the asset allocation strategies consistent with the regulations of the U.K. pension regulators and in consultation with financial advisors and company representatives. Investment managers for the U.S. Plans and the U.K. Plan are given established ranges within which the investments may deviate from the target allocations. For the Norway Plans, we establish minimum returns under the terms of investment contracts with insurance companies.

In the year ended December 31, 2015, 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, 2015, the fair value of the investments in the funded Transocean Plans decreased by $122 million, or seven percent, due to the following: (a) approximately $74 million resulting from funding contributions, net of benefits paid, (b) approximately $39 million resulting from currency appreciation in connection with our funded Non U.S. Plans, and (c) approximately $9 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 U.S. Plans, 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 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

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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, 2015, we contributed $39 million and participants contributed $4 million to the Transocean Plans and the OPEB Plans. In the year ended December 31, 2014, we contributed $101 million and participants contributed $3 million to the Transocean Plans and the OPEB Plans.

For the year ending December 31, 2016, we expect to contribute $52 million to the Transocean Plans and $3 million to the OPEB Plans. These estimated contributions for the Transocean Plans are comprised of $45 million to meet the funding requirements for the funded Non U.S. Plans, and approximately $7 million to fund expected benefit payments for the unfunded U.S. Plans and unfunded Non U.S. Plans.

Benefit payments—Our projected benefit payments for the Transocean Plans and the OPEB Plans are as follows (in millions):

	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Years ending December 31,				
2016	$ 58	$ 12	$ 3	$ 73
2017	62	9	3	74
2018	66	9	3	78
2019	70	10	3	83
2020	73	11	3	87
2021 - 2025	407	88	12	507

Contingencies and Uncertainties

Macondo well incident

On April 22, 2010, the ultra deepwater floater Deepwater Horizon sank after a blowout of the Macondo well caused a fire and explosion on the rig off the coast of Louisiana. At the time of the explosion, Deepwater Horizon was contracted to an affiliate of BP plc (together with its affiliates, “BP”). Litigation commenced shortly after the incident, and most claims against us were consolidated by the U.S. Judicial Panel on Multidistrict Litigation and transferred to the MDL Court. 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, the PSC and the States. We believe the remaining most notable claims against us arising from the Macondo well incident are the potential 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 14—Commitments and Contingencies.

Tax matters

We are a Swiss corporation, and we operate through our various subsidiaries in a number of countries throughout the world. Our provision for income taxes is based on the tax laws and rates applicable in the jurisdictions in which we operate and earn income. The relationship between our provision for or benefit from income taxes and our income or loss before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues rather than income before taxes, (c) rig movements between taxing jurisdictions and (d) our rig operating structures. Generally, our annual marginal tax rate is lower than our annual effective tax rate.

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.

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.

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See Notes to Consolidated Financial Statements—Note 6—Income Taxes and Note 25—Subsequent Events.

Regulatory matters

For a description of regulatory and environmental matters relating to the Macondo well incident, please see "—Macondo well incident."

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, 2015.

Related Party Transactions

As of December 31, 2015, 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 prepared 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. On an ongoing basis, we evaluate our estimates, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, investments, property and equipment, income taxes, defined benefit pension plans and other postretirement employee benefits, contingent liabilities and share based compensation. 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.

We consider the following to be our critical accounting policies and estimates, and 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.

Income taxes—We are a Swiss corporation, operating through our various subsidiaries in a number of countries throughout the world. We have provided 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 ultimate tax liabilities in the various jurisdictions are 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, 2015, the liability for estimated tax exposures in our jurisdictions of operation was approximately $405 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 consider the earnings of certain of our subsidiaries to be indefinitely reinvested. As such, we have not provided for taxes on these unremitted earnings. At December 31, 2015, the amount of indefinitely reinvested earnings was approximately $2.2 billion. Should we make a distribution from the unremitted earnings of these subsidiaries, we would 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, 2015.

We have recognized deferred taxes related to the earnings of certain subsidiaries that are not permanently 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 position, results of operations or cash flows.

Estimates, judgments and assumptions are required in determining whether deferred tax assets will be fully or partially realized. 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, 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 years ended December 31, 2014 and 2013, we did not make any significant changes to our valuation allowance against deferred tax assets.

See Notes to Consolidated Financial Statements—Note 6—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, 2015 and 2014, the carrying amount of our property and equipment was $20.8 billion and $21.5 billion, representing 79 percent and 75 percent of our total assets, respectively.

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, 2015, 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 $41 million and a hypothetical one year decrease would cause an increase in our annual depreciation expense of approximately $61 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, Transocean Partners ultra deepwater floaters, harsh environment floaters, deepwater floaters, midwater floaters, and high specification jackups.

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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 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.

During the three months ended March 31, 2015, we identified indicators that the asset groups in our contract drilling services reporting unit may not be recoverable. Such indicators included a reduction in the number of new contract opportunities, recent low dayrate fixtures and contract terminations. Our deepwater floater asset group, in particular, experienced further declines in projected dayrates and utilization partly caused by more technologically advanced drilling units aggressively competing with less capable drilling units. During the three months ended June 30, 2015, we identified additional indicators that the asset groups in our contract drilling services reporting unit may not be recoverable. Such indicators included additional customer suspensions of drilling programs and cancellations of contracts, and further reduction in the number of new contract opportunities, resulting in reduced dayrate fixtures. Our midwater floater asset group, specifically, experienced further declines in projected dayrates and utilization as drilling activity has sharply declined in the United Kingdom ("U.K.") and Norwegian North Sea, which has accelerated the marginalization of some of the less capable drilling units in this asset group. As a result of our testing, we determined that the carrying amounts of the deepwater floater and the midwater floater asset groups were impaired. In the year ended December 31, 2015, we recognized a loss 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, including a loss of $52 million associated with construction in progress. In each case, we measured the fair value of the asset group by applying a combination of income and cost approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. Our estimates of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates.

During the year ended December 31, 2014, we identified indicators that our asset groups in our contract drilling services reporting unit may be impaired as a result of recent market developments, including recent low dayrate fixtures, partly caused by more technologically advanced drilling units competing with less capable drilling units, and projected declines in dayrates and utilization, particularly for the deepwater floater asset group. We conducted testing for impairment, and as a result, we determined that the carrying amount of the deepwater floater asset group exceeded its fair value. In the year ended December 31, 2014, we recognized a loss of $788 million ($693 million, net of tax) associated with the impairment of these long lived assets. Our estimates of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates. If we experience increasingly unfavorable changes to actual or anticipated dayrates or other impairment indicators, or if we are unable to secure new or extended contracts for our active units or the reactivation of any of our stacked units, we may be required to recognize additional losses in future periods as a result of impairments of the carrying amount of one or more of our asset groups.

See Notes to Consolidated Financial Statements—Note 5 Impairments.

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, 2015 and 2014, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $250 million and $426 million, respectively, recorded in other current liabilities.

See Notes to Consolidated Financial Statements—Note 14—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, including retiree life insurance and medical benefits, are actuarially determined and are affected by assumptions, including long term rate of return, discount rates, mortality rates, compensation increases, employee turnover rates and health care cost trend rates. The two most critical assumptions are the long term rate of return and the discount rate. 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."

Long term rate of return—We develop our assumptions regarding the estimated rate of return on plan assets based on historical experience and projected long term investment returns, considering each plan's target asset allocation and long term asset class expected returns. We regularly review our actual asset allocation and periodically rebalance plan assets as appropriate. At December 31, 2015, a hypothetical percentage point decrease of the expected long term rate of return assumption would result in an increase to net periodic benefit costs of approximately $16 million.

Discount rate—As a basis for determining the discount rate, we utilize a yield curve approach based on Aa rated corporate bonds and the expected timing of future benefit payments. At December 31, 2015, a hypothetical one half percentage point decrease of the discount rate would result in an increase to net periodic benefit costs of approximately $2 million.

See Notes to Consolidated Financial Statements—Note 13—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, our long term and short term debt and our derivative instruments. 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. For our derivative instruments, the following table presents the notional amounts and weighted average interest rates by contractual maturity dates.

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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)							
	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Restricted cash investments								
Fixed rate (NOK)	$ 88	$ 88	$ 41	$ —	$ —	$ —	$ 217	$ 223
Average interest rate	4.15 %	4.15%	4.15 %	— %	— %	— %		
Debt								
Fixed rate (USD)	$ 1,000	$ 598	$ 1,055	$ 32	$ 935	$ 4,672	$ 8,292	$ 6,068
Average interest rate	5.85 %	3.22%	6.36 %	7.76%	6.55%	6.79 %		
Fixed rate (NOK)	$ 89	$ 88	$ 40	$ —	$ —	$ —	$ 217	$ 223
Average interest rate	4.15 %	4.15%	4.15 %	— %	— %	— %		
Interest rate swaps								
Fixed to variable (USD)	$ —	$ —	$ 750	$ —	$ —	$ —	$ 750	$ 2
Average receive rate	— %	— %	6.00 %	— %	— %	— %		
Average pay rate	— %	— %	5.09 %	— %	— %	— %		

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

Interest rate risk—At December 31, 2015 and 2014, the notional amount of our variable rate instruments was approximately $750 million and $1.5 billion, which represented nine percent and 15 percent of the aggregate principal amount of our total debt, respectively, including the effect of our hedging activities. At December 31, 2015 and 2014, we were exposed to the variable interest rates associated with our interest rate swaps. Based upon variable rate notional amounts outstanding as of December 31, 2015 and 2014, a hypothetical one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of approximately $8 million and $15 million, respectively.

At December 31, 2015 and 2014, the fair value of our debt was $6.3 billion and $9.8 billion, respectively. During the year ended December 31, 2015, the fair value of our debt decreased by $3.5 billion due to the following: (a) a decrease of approximately $1.5 billion resulting from the repurchase or redemption of $1.5 billion aggregate principal amount of debt and (b) a decrease of approximately $2.0 billion resulting from the reduced 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, 2015 and 2014, a hypothetical one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $23 million and $26 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. We may engage in hedging activities to mitigate our exposure to currency exchange risk in certain instances through the use of currency exchange derivative instruments, including forward exchange contracts, or spot purchases. A forward exchange contract obligates us to exchange predetermined amounts of specified currencies at a stated exchange rate on a stated date or to make a U.S. dollar payment equal to the value of such exchange.

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 acceptance, local banking laws, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual local currency needs may vary from those anticipated in the customer contracts, resulting in partial exposure to currency exchange rate risk. The effect of fluctuations in currency exchange rates caused by our international operations generally has not had a material impact on our overall operating results. In situations where local currency receipts do not equal local currency requirements, we may use currency exchange derivative instruments, including forward exchange contracts, or spot purchases, to mitigate our currency exchange risk.

At December 31, 2015, we had NOK 1.9 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 an 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, 2015. 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, 2015, the Company's internal control over financial reporting was effective.

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, 2015, 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.

In our opinion, Transocean Ltd. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

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, 2015 and 2014, 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, 2015, and our report dated February 24, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 24, 2016

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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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, 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 February 24, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 24, 2016

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share data)

	Years ended December 31,		
	2015	2014	2013
Operating revenues			
Contract drilling revenues	$ 6,802	$ 8,952	$ 9,070
Other revenues	584	222	179
	7,386	9,174	9,249
Costs and expenses			
Operating and maintenance	2,955	5,110	5,563
Depreciation	963	1,139	1,109
General and administrative	193	234	286
	4,111	6,483	6,958
Loss on impairment	(1,867)	(4,043)	(81)
Gain (loss) on disposal of assets, net	(28)	(26)	7
Operating income (loss)	1,380	(1,378)	2,217
Other income (expense), net			
Interest income	22	39	52
Interest expense, net of amounts capitalized	(432)	(483)	(584)
Other, net	60	22	(29)
	(350)	(422)	(561)
Income (loss) from continuing operations before income tax expense	1,030	(1,800)	1,656
Income tax expense	206	146	258
Income (loss) from continuing operations	824	(1,946)	1,398
Income (loss) from discontinued operations, net of tax	2	(20)	9
Net income (loss)	826	(1,966)	1,407
Net income (loss) attributable to noncontrolling interest	35	(53)	—
Net income (loss) attributable to controlling interest	$ 791	$ (1,913)	$ 1,407
Earnings (loss) per share-basic			
Earnings (loss) from continuing operations	$ 2.16	$ (5.23)	$ 3.85
Earnings (loss) from discontinued operations	—	(0.06)	0.02
Earnings (loss) per share	$ 2.16	$ (5.29)	$ 3.87
Earnings (loss) per share-diluted			
Earnings (loss) from continuing operations	$ 2.16	$ (5.23)	$ 3.85
Earnings (loss) from discontinued operations	—	(0.06)	0.02
Earnings (loss) per share	$ 2.16	$ (5.29)	$ 3.87
Weighted-average shares outstanding			
Basic	363	362	360

Diluted	363	362	360

See accompanying notes.

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)

	Years ended December 31, 2015		2014		2013	
Net income (loss)	$	826	$	(1,966)	$	1,407
Net income (loss) attributable to noncontrolling interest		35		(53)		—
Net income (loss) attributable to controlling interest		791		(1,913)		1,407
Other comprehensive income (loss) before reclassifications						
Components of net periodic benefit costs		63		(170)		198
Loss on derivative instruments		—		—		(5)
Reclassifications to net income						
Components of net periodic benefit costs		23		17		49
(Gain) loss on derivative instruments		—		(2)		18
Other comprehensive income (loss) before income taxes		86		(155)		260
Income taxes related to other comprehensive income (loss)		(16)		13		2
Other comprehensive income (loss)		70		(142)		262
Other comprehensive income attributable to noncontrolling interest		—		—		3

Other comprehensive income (loss) attributable to controlling interest		70		(142)		259
Total comprehensive income (loss)		896		(2,108)		1,669
Total comprehensive income (loss) attributable to noncontrolling interest		35		(53)		3
Total comprehensive income (loss) attributable to controlling interest	$	861	$	(2,055)	$	1,666

See accompanying notes.

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In millions, except share data)

	December 31, 2015	December 31, 2014
Assets		
Cash and cash equivalents	$ 2,339	$ 2,635
Accounts receivable, net		
Trade	1,343	2,084
Other	36	36
Materials and supplies, net	635	818
Assets held for sale	8	25
Restricted cash	340	114
Other current assets	84	128
Total current assets	4,785	5,840
Property and equipment	26,274	28,516
Less accumulated depreciation	(5,456)	(6,978)
Property and equipment, net	20,818	21,538
Deferred income taxes, net	316	360
Other assets	410	833
Total assets	$ 26,329	$ 28,571
Liabilities and equity		
Accounts payable	$ 448	$ 784
Accrued income taxes	82	131
Debt due within one year	1,093	1,032
Other current liabilities	1,046	1,822
Total current liabilities	2,669	3,769
Long-term debt	7,397	9,019
Deferred income taxes, net	339	436
Other long-term liabilities	1,108	1,354
Total long-term liabilities	8,844	10,809
Commitments and contingencies		
Redeemable noncontrolling interest	8	11
Shares, CHF 15.00 par value, 396,260,487 authorized, 167,617,649 conditionally authorized, 373,830,649 issued at December 31, 2015 and 2014 and 364,035,397 and 362,279,530 outstanding at December 31, 2015 and 2014, respectively.	5,193	5,169
Additional paid-in capital	5,739	5,797
Treasury shares, at cost, 2,863,267 held at December 31, 2015 and 2014	(240)	(240)
Retained earnings	4,140	3,349

Accumulated other comprehensive loss	(334)	(404)
Total controlling interest shareholders' equity	14,498	13,671
Noncontrolling interest	310	311
Total equity	14,808	13,982
Total liabilities and equity	$ 26,329	$ 28,571

See accompanying notes.

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(In millions)

	Years ended December 31,			Years ended December 31,		
	2015	2014	2013	2015	2014	2013
	Quantity			Amount		
Shares						
Balance, beginning of period	362	361	360	$ 5,169	$ 5,147	$ 5,130
Issuance of shares under share-based compensation plans	2	1	1	24	22	17
Balance, end of period	364	362	361	$ 5,193	$ 5,169	$ 5,147
Additional paid-in capital						
Balance, beginning of period				$ 5,797	$ 6,784	$ 7,521
Share-based compensation				67	98	113
Issuance of shares under share-based compensation plans				(24)	(21)	(34)
Reclassification of obligation for distribution of qualifying additional paid-in capital				(109)	(1,088)	(808)
Allocated capital for transactions with holders of noncontrolling interest				9	33	(6)
Other, net				(1)	(9)	(2)
Balance, end of period				$ 5,739	$ 5,797	$ 6,784
Treasury shares, at cost						
Balance, beginning of period				$ (240)	$ (240)	$ (240)
Balance, end of period				$ (240)	$ (240)	$ (240)
Retained earnings						
Balance, beginning of period				$ 3,349	$ 5,262	$ 3,855
Net income (loss) attributable to controlling interest				791	(1,913)	1,407
Balance, end of period				$ 4,140	$ 3,349	$ 5,262
Accumulated other comprehensive loss						
Balance, beginning of period				$ (404)	$ (262)	$ (521)
Other comprehensive income (loss) attributable to controlling interest				70	(142)	259
Balance, end of period				$ (334)	$ (404)	$ (262)
Total controlling interest shareholders’ equity						
Balance, beginning of period				$ 13,671	$ 16,691	$ 15,745
Total comprehensive income (loss) attributable to controlling interest				861	(2,055)	1,666
Share-based compensation				67	98	113
Issuance of shares under share-based compensation plans				—	1	(17)
				(109)	(1,088)	(808)

Reclassification of obligation for distribution of qualifying additional paid-in capital			
Allocated capital for transactions with holders of noncontrolling interest	9	33	(6)
Other, net	(1)	(9)	(2)
Balance, end of period	$ 14,498	$ 13,671	$ 16,691
Noncontrolling interest			
Balance, beginning of period	$ 311	$ (6)	$ (15)
Total comprehensive income (loss) attributable to noncontrolling interest	38	(62)	3
Sale of noncontrolling interest, net of issue costs	—	417	—
Reacquired noncontrolling interest	(1)	—	—
Distributions to holders of noncontrolling interest	(29)	(5)	—
Allocated capital for transactions with holders of noncontrolling interest	(9)	(33)	6
Balance, end of period	$ 310	$ 311	$ (6)
Total equity			
Balance, beginning of period	$ 13,982	$ 16,685	$ 15,730
Total comprehensive income (loss)	899	(2,117)	1,669
Share-based compensation	67	98	113
Issuance of shares under share-based compensation plans	—	1	(17)
Reclassification of obligation for distribution of qualifying additional paid-in capital	(109)	(1,088)	(808)
Sale of noncontrolling interest, net of issue costs	—	417	—
Reacquired noncontrolling interest	(1)	—	—
Distributions to holders of noncontrolling interest	(29)	(5)	—
Other, net	(1)	(9)	(2)
Balance, end of period	$ 14,808	$ 13,982	$ 16,685

See accompanying notes.

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TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years ended December 31,		
	2015	2014	2013
Cash flows from operating activities			
Net income (loss)	$ 826	$ (1,966)	$ 1,407
Adjustments to reconcile to net cash provided by operating activities:			
Amortization of drilling contract intangibles	(15)	(15)	(15)
Depreciation	963	1,139	1,109
Share-based compensation expense	67	98	113
Loss on impairment	1,867	4,043	81
Loss on impairment of assets in discontinued operations	—	—	14
(Gain) loss on disposal of assets, net	28	26	(7)
(Gain) loss on disposal of assets in discontinued operations, net	(1)	10	(54)
Deferred income tax benefit	(78)	(142)	(9)
Other, net	66	52	99
Changes in deferred revenue, net	(90)	106	(78)
Changes in deferred expenses, net	176	(48)	74
Changes in operating assets and liabilities	(364)	(1,083)	(816)
Net cash provided by operating activities	3,445	2,220	1,918
Cash flows from investing activities			
Capital expenditures	(2,001)	(2,165)	(2,238)
Proceeds from disposal of assets, net	51	215	174
Proceeds from disposal of assets in discontinued operations, net	3	35	204
Proceeds from sale of preference shares	—	—	185
Proceeds from repayment of notes and loans receivable	15	101	17
Investment in loans receivable	—	(15)	—
Other, net	—	1	—
Net cash used in investing activities	(1,932)	(1,828)	(1,658)
Cash flows from financing activities			
Repayments of debt	(1,506)	(539)	(1,692)
Proceeds from restricted cash investments	110	176	298
Deposits to restricted cash investments	—	(20)	(119)
Proceeds from sale of noncontrolling interest	—	443	—
Issue costs for sale of noncontrolling interest	—	(26)	—
Distributions of qualifying additional paid-in capital	(381)	(1,018)	(606)
Distributions to holders of noncontrolling interest	(29)	(5)	—
Other, net	(3)	(11)	(32)
Net cash used in financing activities	(1,809)	(1,000)	(2,151)
Net increase (decrease) in cash and cash equivalents	(296)	(608)	(1,891)

Cash and cash equivalents at beginning of period	2,635	3,243	5,134
Cash and cash equivalents at end of period	$ 2,339	$ 2,635	$ 3,243

See accompanying notes.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business

Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean," "we," "us" or "our") is a leading international provider of offshore contract drilling services for oil and gas wells. We specialize in technically demanding sectors of the offshore drilling business with a particular focus on deepwater and harsh environment drilling services. Our mobile offshore drilling fleet is considered one of the most versatile fleets in the world. We contract our drilling rigs, related equipment and work crews predominantly on a dayrate basis to drill oil and gas wells. At December 31, 2015, we owned or had partial ownership interests in and operated 60 mobile offshore drilling units, including 27 ultra deepwater floaters, seven harsh environment floaters, five deepwater floaters, 11 midwater floaters and 10 high specification jackups. At December 31, 2015, we also had seven ultra deepwater drillships and five high specification jackups under construction or under contract to be constructed. See Note 9—Drilling Fleet.

On October 29, 2015, shareholders at our extraordinary general meeting 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. See Note 16—Shareholders' Equity and Note 25—Subsequent Events.

On August 5, 2014, we completed an initial public offering to sell a noncontrolling interest in Transocean Partners LLC ("Transocean Partners"), a Marshall Islands limited liability company, which was formed on February 6, 2014, by Transocean Partners Holdings Limited, a Cayman Islands company and our wholly owned subsidiary, to own, operate and acquire modern, technologically advanced offshore drilling rigs. See Note 15—Noncontrolling Interest.

In February 2014, in connection with our efforts to discontinue non strategic operations, we completed the sale of Applied Drilling Technology International Limited ("ADTI"), a United Kingdom ("U.K.") company, which performs drilling management services in the North Sea. In March 2012, we announced our intent to discontinue drilling management operations in the shallow waters of the U.S. Gulf of Mexico, upon completion of our then existing contracts. In December 2012, we completed the final project of our drilling management services operations in the U.S. Gulf of Mexico and discontinued offering our drilling management services in this region. See Note 7—Discontinued Operations.

Note 2—Significant Accounting Policies

Accounting estimates—To prepare financial statements in accordance with accounting principles generally accepted in the U.S., we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates and assumptions, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, property and equipment, assets held for sale, income taxes, contingencies, share based compensation, defined benefit pension plans and other postretirement benefits. We base our estimates and assumptions on historical experience and on various other factors 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 could differ from such estimates.

Fair value measurements—We estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation techniques require inputs that we categorize using a three level hierarchy, from highest to lowest level of observable inputs, as follows: (1) significant observable inputs, including unadjusted quoted prices for identical assets or liabilities in active markets (“Level 1”), (2) significant other observable inputs, including direct or indirect market data for similar assets or liabilities in active markets or identical assets or liabilities in less active markets (“Level 2”) and (3) significant unobservable inputs, including those that require considerable judgment for which there is little or no market data (“Level 3”). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Consolidation—We consolidate entities in which we have a majority voting interest and entities that meet the criteria for variable interest entities for which we are deemed to be the primary beneficiary for accounting purposes. We eliminate intercompany transactions and accounts in consolidation. We apply the equity method of accounting for an investment in an entity if we have the ability to exercise significant influence over the entity that (a) does not meet the variable interest entity criteria or (b) meets the variable interest entity criteria, but for which we are not deemed to be the primary beneficiary. We apply the cost method of accounting for an investment in an entity if we do not have the ability to exercise significant influence over the unconsolidated entity. We separately present within equity on our consolidated balance sheets the ownership interests attributable to parties with noncontrolling interests in our consolidated subsidiaries, and we separately present net income attributable to such parties on our consolidated statements of operations. See Note 4—Variable Interest Entities and Note 15—Noncontrolling interest.

Discontinued operations—Under accounting standards previously in effect, we presented as discontinued operations the operating results of components of our business that either had been disposed of or were classified as held for sale when both of the following conditions were met: (a) the operations and cash flows of the component had been or would be eliminated from our ongoing operations as a result of the disposal transaction and (b) we would not have any significant continuing involvement in the operations of the disposed component. Under the former accounting standards, we considered a component of our business to be one that comprises operations and

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cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of our business. See Note 3—New Accounting Pronouncements and Note 7—Discontinued Operations.

Operating revenues and expenses—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. In connection with drilling contracts, we may receive revenues for preparation and mobilization of equipment and personnel or for capital improvements to rigs. We defer the revenues earned and incremental costs incurred that are directly related to contract preparation and mobilization and recognize such revenues and costs over the primary contract term of the drilling project using the straight line method. We amortize contract drilling intangible revenues based on the cash flows projected over the respective contract period and include such revenues in contract drilling revenues on our consolidated statements of operations (see Note 10—Intangible Liabilities). We amortize, in operating and maintenance costs and expenses, the fees related to contract preparation and mobilization on a straight line basis over the estimated firm period of drilling, which is consistent with the general pace of activity, level of services being provided and dayrates being earned over the life of the contract. For contractual daily rate contracts, we recognize the losses for loss contracts as such losses are incurred. We recognize the costs of relocating drilling units without contracts to more promising market sectors as such costs are incurred. Upon completion of drilling contracts, we recognize in earnings any demobilization fees received and expenses incurred. We defer capital upgrade revenues received and recognize such revenues over the primary contract term of the drilling project. We depreciate the actual costs incurred for the capital upgrade on a straight line basis over the estimated useful life of the asset. We defer the periodic survey and drydock costs incurred in connection with obtaining regulatory certification to operate our rigs and well control systems on an ongoing basis, and we recognize such costs over the period until the next survey using the straight-line method.

Our other revenues represent those derived from customer contract terminations and customer reimbursable items. We recognize revenues from contract terminations as we fulfill our obligations for such terminations and when all contingencies have expired. We recognize customer reimbursable revenues as we bill our customers for reimbursement of costs associated with certain equipment, materials and supplies, subcontracted services, employee bonuses and other expenditures, resulting in little or no net effect on operating income since such recognition is concurrent with the recognition of the respective reimbursable costs in operating and maintenance expense.

Share based compensation—For service awards, we recognize compensation expense on a straight line basis over the service period through the date the employee or non employee director is no longer required to provide service to earn the award. For performance awards with graded vesting conditions, we recognize compensation expense on a straight line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards. We recognize share based compensation expense net of a forfeiture rate that we estimate at the time of grant based on historical experience and future expectations, and we adjust the estimated forfeiture rate, if necessary, in subsequent periods based on actual forfeitures or changed expectations.

To measure the fair values of stock options and stock appreciation rights granted or modified, we use the Black Scholes Merton option pricing model and apply assumptions for the expected life, risk free interest rate, dividend yield and expected volatility. The expected life is based on historical information of past employee behavior regarding exercises and forfeitures of options. The risk free interest rate is based upon the published U.S. Treasury yield curve in effect at the time of grant or modification for instruments with a similar life. The dividend yield is based on our history and expectation of dividend payouts. The expected volatility is based on a blended rate with an equal weighting of the (a) historical volatility based on historical data for an amount of time approximately equal to the expected life and (b) implied volatility derived from our at the money, long dated call options. To measure the fair values of granted or modified service based restricted share units, we use the market price of our shares on the grant date or modification date. To measure the fair values of restricted share units that are subject to performance targets, we use the market price of our shares on the measurement date for the projected number of shares expected to be earned at the end of the performance period. To measure the fair values of granted or modified restricted share units that are subject to market factors, we use a Monte Carlo simulation model and, in addition to the assumptions applied for the Black Scholes Merton option pricing model, we apply assumptions using a risk neutral approach and an average price at the performance start date. The risk neutral approach assumes that all peer group stocks grow at the risk free rate. The average price at the performance start date is based on the average stock price for the preceding 30 trading days.

We recognize share based compensation expense in the same financial statement line item as cash compensation paid to the respective employees or non employee directors. We recognize cash flows resulting from the tax deduction benefits for awards in excess of recognized compensation costs as financing cash flows. In the years ended December 31, 2015, 2014 and 2013, share based compensation expense was $67 million, $98 million and $113 million, respectively. In the years ended December 31, 2015, 2014 and 2013, income tax benefit on share based compensation expense was $11 million, $15 million and $17 million, respectively. See Note 17—Share Based Compensation Plans.

Capitalized interest—We capitalize interest costs for qualifying construction and upgrade projects. In the years ended December 31, 2015, 2014 and 2013, we capitalized interest costs of $140 million, $133 million and $78 million, respectively, for our construction work in progress.

Foreign currency—We consider the U.S. dollar to be the functional currency for all of our operations since the majority of our revenues and expenditures are denominated in U.S. dollars, which limits our exposure to currency exchange rate fluctuations. We recognize foreign currency exchange gains and losses in other, net. In the years ended December 31, 2015, 2014 and 2013, we recognized net foreign currency exchange gains (losses) of less than $1 million, $18 million and $(11) million, respectively. See Note 12—Derivatives and Hedging.

Income taxes—We provide for income taxes based upon the tax laws and rates in effect in the countries in which operations are conducted and income is earned. There is little or no expected relationship between the provision for or benefit from income taxes and income or loss before income taxes because the countries in which we operate have taxation regimes that vary not only with respect to nominal rate, but also in terms of the availability of deductions, credits and other benefits. Variations also arise because income earned and taxed in any particular country or countries may fluctuate from year to year.

We recognize deferred tax assets and liabilities for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of our assets and liabilities using the applicable jurisdictional tax rates in effect at year end. We record a valuation allowance for deferred tax assets when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We also record a valuation allowance for deferred tax assets resulting from net operating losses incurred during the year in certain jurisdictions and for other deferred tax assets where, in our opinion, it is more likely than not that the financial statement benefit of these losses will not be realized. Additionally, we record a valuation allowance for foreign tax credit carryforwards to reflect the possible expiration of these benefits prior to their utilization.

We maintain liabilities for estimated tax exposures in our jurisdictions of operation, and we recognize the provisions and benefits resulting from changes to those liabilities in our income tax expense or benefit along with related interest and penalties. Tax exposure items include potential challenges to permanent establishment positions, intercompany pricing, disposition transactions, and withholding tax rates and their applicability. These tax 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. See Note 6—Income Taxes.

Cash and cash equivalents—We consider cash equivalents to include highly liquid debt instruments with original maturities of three months or less such as time deposits with commercial banks that have high credit ratings, U.S. Treasury and government securities, Eurodollar time deposits, certificates of deposit and commercial paper. We may also invest excess funds in no load, open ended, management investment trusts. Such management trusts invest exclusively in high quality money market instruments.

We maintain restricted cash balances and investments that are either pledged for debt service, as required under certain bank credit agreements, or held in accounts that are subject to restrictions due to legislation, regulation or court order. We classify such restricted cash investment balances in other current assets if the restriction is expected to expire or otherwise be resolved within one year and in other assets if the restriction is expected to expire or otherwise be resolved in greater than one year. At December 31, 2015, the aggregate carrying amount of our restricted cash investments was $467 million, of which $340 million and $127 million was classified in other current assets and other assets, respectively. At December 31, 2014, the aggregate carrying amount of our restricted cash investments was $377 million, of which $114 million and $263 million was classified in other current assets and other assets, respectively. See Note 11—Debt and Note 14—Commitments and Contingencies.

Accounts receivable—We earn our revenues by providing our drilling services to international oil companies and government owned or government controlled oil companies. We evaluate the credit quality of our customers on an ongoing basis, and we do not generally require collateral or other security to support customer receivables. We establish an allowance for doubtful accounts on a case by case basis, considering changes in the financial position of a customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. At December 31, 2015 and 2014, the allowance for doubtful accounts was less than \$1 million and \$14 million, respectively.

Materials and supplies—We record materials and supplies at their average cost less an allowance for obsolescence. We estimate the allowance for obsolescence based on historical experience and expectations for future use of the materials and supplies. At December 31, 2015 and 2014, the allowance for obsolescence was \$148 million and \$109 million, respectively.

Assets held for sale—We classify an asset as held for sale when the facts and circumstances meet the criteria for such classification, including the following: (a) we have committed to a plan to sell the asset, (b) the asset is available for immediate sale, (c) we have initiated actions to complete the sale, including locating a buyer, (d) the sale is expected to be completed within one year, (e) the asset is being actively marketed at a price that is reasonable relative to its fair value, and (f) the plan to sell is unlikely to be subject to significant changes or termination. At December 31, 2015 and 2014, the aggregate carrying amount of our assets held for sale was \$8 million and \$25 million, respectively. See Note 7—Discontinued Operations and Note 9—Drilling Fleet.

Property and equipment—The carrying amounts of our property and equipment, consisting primarily of offshore drilling rigs and related equipment, are based on our estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values of our rigs. These estimates, assumptions and judgments reflect both historical experience and expectations regarding future industry conditions and operations. At December 31, 2015, the aggregate carrying amount of our property and equipment represented approximately 79 percent of our total assets.

We capitalize expenditures for newbuilds, renewals, replacements and improvements, including capitalized interest, if applicable, and we recognize the expense for maintenance and repair costs as incurred. For newbuild construction projects, we also capitalize the initial

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preparation, mobilization and commissioning costs incurred until the drilling unit is placed into service. Upon sale or other disposition of an asset, we recognize a net gain or loss on disposal of the asset, which is measured as the difference between the net carrying amount of the asset and the net proceeds received. We compute depreciation using the straight line method after allowing for salvage values.

The estimated original useful lives of our drilling units range from 18 to 35 years, our buildings and improvements range from 10 to 30 years and our machinery and equipment range from four to 20 years. 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.

As of December 31, 2014, we adjusted the salvage values of certain drilling units due to existing market conditions. In the year ended December 31, 2015, the changes in estimated salvage values resulted in an increase in depreciation expense of approximately $51 million ($48 million, or $0.13 per diluted share, net of tax). During the year ended December 31, 2013, we adjusted the useful lives for five rigs, extending the estimated useful lives from between 29 and 40 years to between 35 and 44 years. We deemed the life extensions appropriate for each of these rigs based on the respective contracts under which the rigs were operating and the additional life extending work, upgrades and inspections we performed on the rigs. In year ended December 31, 2013, the changes in estimated useful lives of these rigs resulted in a reduction in annual depreciation expense of $3 million ($0.01 per diluted share), which had no tax effect.

Long lived asset impairment—We review the carrying amounts of long lived assets, principally property and equipment, for potential impairment when events occur or circumstances change that indicate that the carrying amount of such assets may not be recoverable.

For assets classified as held and used, we determine recoverability by evaluating the estimated undiscounted future net cash flows based on projected dayrates and utilization of the asset group under review. We consider our asset groups to be ultra deepwater floaters, Transocean Partners ultra deepwater floaters, harsh environment floaters, deepwater floaters, midwater floaters and high specification jackups. When an impairment of one or more of our asset groups is indicated, we measure the impairment as the amount by which the asset group's carrying amount exceeds its estimated fair value. We measure the fair values of our contract drilling asset groups by applying a variety of valuation methods, incorporating a combination of cost, income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. For an asset classified as held for sale, we consider the asset to be impaired to the extent its carrying amount exceeds its estimated fair value less cost to sell.

In the year ended December 31, 2015, we determined that the carrying amount of the deepwater floater asset group and the midwater floater asset group each exceeded its fair value, and we recognized a loss of $507 million ($481 million, or $1.31 per diluted share, net of tax) and $668 million ($654 million, or $1.78 per diluted share, net of tax) associated with the impairment of the deepwater floater asset group and the midwater floater asset group, respectively, including a loss of $52 million associated with construction in progress related to the asset groups. In the year ended December 31, 2014, we determined that the carrying amount of the deepwater floater asset group exceeded its fair value, and we recognized a loss of $788 million ($693 million, or $1.91 per diluted share, net of tax) associated with the impairment of these long lived assets. If we experience increasingly unfavorable changes to actual or anticipated dayrates or other impairment indicators, or if we are unable to secure new or extended contracts for our active units or the reactivation of any of our stacked units, we may be required to recognize additional losses in future periods as a result of impairments of the carrying amount of one or more of our asset groups. See Note 5—Impairments.

Goodwill impairment—Prior to the full impairment of our goodwill, we conducted impairment testing annually as of October 1 and more frequently, on an interim basis, when an event occured or circumstances changed that indicated that the fair value of our reporting unit may have declined below its carrying value. We tested goodwill at the reporting unit level, which is defined as an operating segment or one level below an operating segment that constitutes a business for which financial information is available and is regularly reviewed by management. We determined that we had a single reporting unit for this purpose.

We estimate the fair value of our reporting unit using projected discounted cash flows, publicly traded company multiples and acquisition multiples. To develop the projected cash flows associated with our reporting unit, which are based on estimated future dayrates and rig utilization, we consider key factors that include assumptions regarding future commodity prices, credit market conditions and the effect these factors may have on our contract drilling operations and the capital expenditure budgets of our customers. We discount the projected cash flows using a long term, risk adjusted weighted average cost of capital, which is based on our estimate of the investment returns that market participants would require for each of our reporting units. We derive publicly traded company multiples for companies with operations similar to our reporting units using observable information related to shares traded on stock exchanges and, when available, observable information related to recent acquisitions. If the reporting unit's carrying amount exceeds its fair value, we consider goodwill impaired and perform a second step to measure the amount of the impairment loss, if any.

In the year ended December 31, 2014, as a result of interim goodwill tests, we recognized an aggregate loss of $3.0 billion, which had no tax effect, associated with the full impairment of the carrying amount of our goodwill, of which $2.9 billion ($8.02 per diluted share) was attributable to controlling interest and $74 million was attributable to noncontrolling interest. In the year ended December 31, 2013, as a result of our annual goodwill impairment test, we concluded that our goodwill was not impaired. See Note 5—Impairments.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Derivatives and hedging—From time to time, we may enter into a variety of derivative financial instruments in connection with the management of our exposure to variability in interest rates and currency exchange rates. We record derivatives on our consolidated balance sheet, measured at fair value. For derivatives that do not qualify for hedge accounting, we recognize the gains and losses associated with changes in the fair value in current period earnings.

We may enter into cash flow hedges to manage our exposure to variability of the expected future cash flows of recognized assets or liabilities or of unrecognized forecasted transactions. For a derivative that is designated and qualifies as a cash flow hedge, we initially recognize the effective portion of the gains or losses in other comprehensive income and subsequently recognize the gains and losses in earnings in the period in which the hedged forecasted transaction affects earnings. We recognize the gains and losses associated with the ineffective portion of the hedges in interest expense in the period in which they are realized.

We may enter into fair value hedges to manage our exposure to changes in fair value of recognized assets or liabilities, such as fixed rate debt, or of unrecognized firm commitments. For a derivative that is designated and qualifies as a fair value hedge, we simultaneously recognize in current period earnings the gains or losses on the derivative along with the offsetting losses or gains on the hedged item attributable to the hedged risk. The resulting ineffective portion, which is measured as the difference between the change in fair value of the derivative and the hedged item, is recognized in current period earnings. See Note 12—Derivatives and Hedging, Note 20—Financial Instruments and Note 21—Risk Concentration.

Pension and other postretirement benefits—We use a measurement date of January 1 for determining net periodic benefit costs and December 31 for determining plan benefit obligations and the fair values of plan assets. We determine our net periodic benefit costs based on a market related value of assets that reduces year to year volatility by including investment gains or losses subject to amortization over a five year period from the year in which they occur. Investment gains or losses for this purpose are measured as the difference between the expected return calculated using the market related value of assets and the actual return based on 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.

We measure our actuarially determined obligations and related costs for our defined benefit pension and other postretirement benefit plans, retiree life insurance and medical benefits, by applying assumptions, including long term rate of return on plan assets, discount rates, mortality rates, compensation increases, employee turnover rates and health care cost trend rates. The two most critical assumptions are the long term rate of return on plan assets and the discount rate.

For the long term rate of return, we develop our assumptions regarding the expected rate of return on plan assets based on historical experience and projected long term investment returns, and we weight the assumptions based on each plan's asset allocation. For the discount rate, we base our assumptions on a yield curve approach using Aa rated corporate bonds and the expected timing of future benefit payments. For the projected compensation trend rate, we consider short term and long term compensation expectations for participants, including salary increases and performance bonus payments. For the health care cost trend rate for other postretirement benefits, we establish our assumptions for health care cost trends, applying an initial trend rate that reflects both our recent historical experience and broader national statistics with an ultimate trend rate that assumes that the portion of gross domestic product devoted to health care eventually becomes constant.

At December 31, 2015 and 2014, our pension and other postretirement benefit plan obligations represented an aggregate liability of $412 million and $521 million, respectively, representing the amount of their net underfunded status. In the years ended December 31, 2015, 2014 and 2013, net periodic benefit costs were $26 million, $75 million and $132 million, respectively. See Note 13—Postemployment Benefit Plans.

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 those 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 expense for legal costs as they are incurred, and we recognize a corresponding asset for such legal costs only if we expect such legal costs to be recovered through insurance.

Reclassifications—We have made certain reclassifications, such as those related to our adoption of updates to accounting standards for interest and income taxes, which did not have an effect on net income, to prior period amounts to conform with the current year's presentation. These reclassifications did not have a material effect on our consolidated statement of financial position, results of operations or cash flows.

Subsequent events—We evaluate subsequent events through the time of our filing on the date we issue our financial statements. See Note 25—Subsequent Events.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Note 3—New Accounting Pronouncements

Recently adopted accounting standards

Presentation of financial statements—Effective January 1, 2015, we adopted the accounting standards update that changes the criteria for reporting discontinued operations. The update expands the disclosures for discontinued operations and requires new disclosures related to the disposal of individually significant components of an entity that do not qualify for discontinued operations. The update is effective for interim and annual periods beginning on or after December 15, 2014 and does not apply to components, such as our discontinued operations, that have been evaluated and reported as discontinued operations under previous guidance. Our adoption did not have an effect on our consolidated financial statements or the disclosures contained in our notes to consolidated financial statements.

Interest—Effective December 31, 2015, we elected to early adopt the accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The update is effective for interim and annual periods beginning after December 15, 2015 and early adoption is permitted. At December 31, 2014, as a result of our adoption, we reclassified $41 million of debt issuance costs to our recognized debt liabilities from other assets on our consolidated balance sheet.

Income taxes—Effective December 31, 2015, we elected to early adopt, on a retrospective basis, the accounting standards update that requires deferred tax liabilities and assets to be classified as noncurrent in a classified statement of financial position. The update is effective for interim and annual periods beginning after December 15, 2016 and early adoption is permitted. We elected to apply the accounting standards update to the prior year on a retrospective basis for comparability purposes. At December 31, 2014, as a result of our adoption, we reclassified $161 million of deferred income taxes to noncurrent assets and long term liabilities from current assets on our consolidated balance sheet.

Recently issued accounting standards

Presentation of financial statements—Effective with our annual report for the year ending December 31, 2016, we will adopt the accounting standards update that requires us to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about our ability to continue as a going concern within one year after the date that the financial statements are issued. The update is effective for the annual period ending after December 15, 2016 and for interim and annual periods thereafter. We do not expect that our adoption will have a material effect on the disclosures contained in our notes to consolidated financial statements.

Revenue from contracts with customers—Effective January 1, 2018, we will adopt the accounting standards update that requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The update was originally effective for interim and annual periods beginning on or after December 15, 2016, but has since been approved for a one year deferral, effective for interim and annual periods beginning on or after December 15, 2017, and permits adoption as early as the original effective date. We are evaluating the requirements to determine the effect such requirements may have on our revenue recognition policies.

Note 4—Variable Interest Entities

Consolidated variable interest entities—The carrying amounts associated with our consolidated variable interest entities, after eliminating the effect of intercompany transactions, were as follows (in millions):

	Years ended December 31,	
	2015	2014
Assets	$ 1,157	$ 1,257
Liabilities	49	74
Net carrying amount	$ 1,108	$ 1,183

Angola Deepwater Drilling Company Limited (“ADDCL”), a consolidated Cayman Islands company, and Transocean Drilling Services Offshore Inc. (“TDSOI”), a consolidated British Virgin Islands Company, were joint venture companies formed to own and operate certain drilling units. We determined that each of these joint venture companies met the criteria of a variable interest entity for accounting purposes because its equity at risk was insufficient to permit it to carry on its activities without additional subordinated financial support from us. We also determined, in each case, that we were the primary beneficiary for accounting purposes since (a) we had the power to direct the construction, marketing and operating activities, which are the activities that most significantly impact each entity’s economic performance, and (b) we had the obligation to absorb losses or the right to receive a majority of the benefits that could be potentially significant to the variable interest entity. As a result, we consolidated ADDCL and TDSOI in our consolidated financial statements, we eliminated intercompany transactions, and we presented the interests that were not owned by us as noncontrolling interest on our consolidated balance sheets.

In October 2012, Angco II, a Cayman Islands company, acquired a 30 percent interest in TDSOI, a British Virgin Islands joint venture company formed to own and operate Transocean Honor. We hold the remaining 70 percent interest in TDSOI. Under certain

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circumstances, Angco II will have 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 high specification jackup, subject to certain adjustments.

Unconsolidated variable interest entities—We previously held two notes receivable, which represented a variable interest in Awilco Drilling plc (“Awilco”), a U.K. company listed on the Oslo Stock Exchange. The notes receivable were originally accepted in exchange for, and were secured by, two drilling units. The notes receivable had stated interest rates of nine percent and were payable in scheduled quarterly installments of principal and interest through maturity in January 2015. In April 2014, Awilco prepaid the notes, liquidating our variable interest, and we received aggregate cash proceeds of $98 million and recognized a gain of $7 million, recorded in other income, associated with the prepayment.

Note 5—Impairments

Assets held and used—During the three months ended March 31, 2015, we identified indicators that the asset groups in our contract drilling services reporting unit may not be recoverable. Such indicators included a reduction in the number of new contract opportunities, recent low dayrate fixtures and contract terminations. Our deepwater floater asset group, in particular, experienced further declines in projected dayrates and utilization partly caused by more technologically advanced drilling units aggressively competing with less capable drilling units. During the three months ended June 30, 2015, we identified additional indicators that the asset groups in our contract drilling services reporting unit may not be recoverable. Such indicators included additional customer suspensions of drilling programs and cancellations of contracts, and further reduction in the number of new contract opportunities, resulting in reduced dayrate fixtures. Our midwater floater asset group, specifically, experienced further declines in projected dayrates and utilization as drilling activity has sharply declined in the United Kingdom (“U.K.”) and Norwegian North Sea, which has accelerated the marginalization of some of the less capable drilling units in this asset group. As a result of our testing, we determined that the carrying amounts of the deepwater floater and the midwater floater asset groups were impaired. In the year ended December 31, 2015, we recognized a loss of $507 million ($481 million, or $1.31 per diluted share, net of tax) and $668 million ($654 million, or $1.78 per diluted share, net of tax) associated with the impairment of the deepwater floater asset group and the midwater floater asset group, respectively, including a loss of $52 million associated with construction in progress related to the asset groups. In each case, we measured the fair value of the asset group by applying a combination of income and cost approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. Our estimates of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates.

During the year ended December 31, 2014, we identified indicators that our asset groups in our contract drilling services reporting unit may be impaired as a result of recent market developments, including recent low dayrate fixtures, partly caused by more technologically advanced drilling units competing with less capable drilling units, and projected declines in dayrates and utilization, particularly for the deepwater floater asset group. We conducted testing for impairment, and as a result, we determined that the carrying amount of the deepwater floater asset group exceeded its fair value. In the year ended December 31, 2014, we recognized a loss of $788 million ($693 million, or $1.91 per diluted share from continuing operations, net of tax) associated with the impairment of these long lived assets. We measured the fair value of the asset group by applying a combination of income, market and cost approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. Our estimate of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rigs availability and dayrates.

In the year ended December 31, 2013, we recognized a loss of $17 million associated with the impairment of certain corporate assets under construction. We estimated the fair value of the assets using significant other observable inputs, representative of a Level 2 fair value measurement, including comparable market data for the corporate assets.

If we experience increasingly unfavorable changes to actual or anticipated dayrates or other impairment indicators, or if we are unable to secure new or extended contracts for our active units or the reactivation of any of our stacked units, we may be required to recognize additional losses in future periods as a result of impairments of the carrying amount of one or more of our asset groups.

Assets held for sale—In the year ended December 31, 2015, we recognized an aggregate loss of $692 million ($578 million, or $1.58 per diluted share, net of tax) associated with the impairment of the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Deepwater Navigator, Discoverer Seven Seas, GSF Celtic Sea, Sedco 707 and Transocean Rather and the midwater floaters GSF Aleutian Key, GSF Arctic III, GSF Grand Banks, GSF Rig 135, Transocean Amirante and Transocean Legend, along with related equipment, which were classified as assets held for sale at the time of impairment. We measured the impairment of the drilling units and related equipment as the amount by which the carrying amount exceeded the estimated fair value less costs to sell. We estimated the fair value of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including indicative market values for the drilling units and related equipment to be sold for scrap value.

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In the year ended December 31, 2014, we recognized an aggregate loss of $268 million ($221 million, or $0.60 per diluted share from continuing operations, net of tax) associated with the impairment of the deepwater floaters Discoverer Seven Seas, Sedco 709, Sedco 710 and Sovereign Explorer, the midwater floaters C. Kirk Rhein, Jr., Falcon 100, GSF Arctic I, J.W. McLean, Sedco 601, Sedco 700, Sedco 703 and Sedneth 701 and the high specification jackups GSF Magellan and GSF Monitor, along with related equipment, which were classified as assets held for sale at the time of impairment. We measured the impairments of the drilling units and related equipment as the amount by which the carrying amount exceeded the estimated fair value less costs to sell. We estimated the fair value of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including, in the case of GSF Magellan and GSF Monitor, binding sale and purchase agreements for the drilling units and related equipment or, in the case of Sedco 710, Sovereign Explorer, GSF Arctic I, J.W. McLean, Sedco 601 and Sedco 700, indicative market values for the drilling units and related equipment to be sold for scrap value.

In the year ended December 31, 2013, we recognized an aggregate loss of $64 million ($0.17 per diluted share), which had no tax effect, associated with the impairment of the deepwater floater Sedco 709, the midwater floaters C. Kirk Rhein, Jr. and Sedco 703 and the high specification jackup GSF Monitor, all of which were classified as assets held for sale at the time of impairment. We measured the impairments of the drilling units and related equipment as the amount by which the carrying amounts exceeded the estimated fair values less costs to sell. We estimated the fair values of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including, in the case of GSF Monitor, a binding sale and purchase agreement, or, in the case of Sedco 709, C. Kirk Rhein, Jr. and Sedco 703, nonbinding sale and purchase agreements for the drilling units and related equipment.

If we commit to plans to sell additional rigs for values below the respective carrying amounts, we may be required to recognize additional losses in future periods associated with the impairment of such assets.

Goodwill—During the year ended December 31, 2014, we noted rapid and significant declines in the market value of our stock, oil and natural gas prices and actual and projected declines in dayrates and utilization. We identified these as indicators that the fair value of our goodwill could have fallen below its carrying amount. As a result, we performed interim goodwill impairment tests and determined that the goodwill associated with our contract drilling services reporting unit was fully impaired. In the year ended December 31, 2014, we recognized an aggregate loss of $3.0 billion associated with the full impairment of the carrying amount of our goodwill, which had no tax effect. We determined that, of the $3.0 billion aggregate loss, $2.9 billion ($8.02 per diluted share) was attributable to controlling interest and $74 million was attributable to noncontrolling interest. We estimated the implied fair value of the goodwill using a variety of valuation methods, including the income and market approaches. Our estimate of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our contract drilling services reporting unit, such as future oil and natural gas prices, projected demand for our services, rig availability and dayrates. As a result of our annual impairment test, performed as of October 1, 2013, we determined that our goodwill was not impaired.

Note 6—Income Taxes

Tax rate—Transocean Ltd., a holding company and Swiss resident, is exempt from cantonal and communal income tax in Switzerland, but is subject to Swiss federal income tax. At the federal level, qualifying net dividend income and net capital gains on the sale of qualifying investments in subsidiaries are exempt from Swiss federal income tax. Consequently, Transocean Ltd. expects dividends from its subsidiaries and capital gains from sales of investments in its subsidiaries to be exempt from Swiss federal income tax.

Our provision for income taxes is based on the tax laws and rates applicable in the jurisdictions in which we operate and earn income. The relationship between our provision for or benefit from income taxes and our income or loss before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues rather than income before taxes, (c) rig movements between taxing jurisdictions and (d) our rig operating structures. Generally, our annual marginal tax rate is lower than our annual effective tax rate.

Effective April 1, 2015, the U.K introduced the diverted profits tax within its Summer Finance Bill 2015, which imposes tax on groups that use certain tax planning techniques that are perceived as diverting profits from the U.K. The change in the law did not affect our existing annual income tax rate or deferred tax balances. In the years ended December 31, 2015, 2014 and 2013, our annual effective tax rate was 16.4 percent, 18.7 percent and 20.1 percent, respectively.

On December 18, 2015, Norwegian authorities reduced the corporate income tax rate to 25 percent from 27 percent, effective January 1, 2016. We have applied this change in determining our annual effective tax rate. The change in Norwegian tax law resulted in a decrease of $11 million to income tax expense resulting from the application of the newly enacted tax rate to our existing deferred tax balances.

The components of our provision (benefit) for income taxes were as follows (in millions):

	Years ended December 31,		
	2015	2014	2013
Current tax expense	$ 284	$ 288	$ 267
Deferred tax benefit	(78)	(142)	(9)
Income tax expense	$ 206	$ 146	$ 258

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

The following is a reconciliation of the differences between the income tax expense for our continuing operations computed at the Swiss holding company federal statutory rate of 7.83 percent and our reported provision for income taxes (in millions):

	Years ended December 31,		
	2015	2014	2013
Income tax expense at the Swiss federal statutory rate	$ 80	$ (141)	$ 130
Taxes on earnings subject to rates different than the Swiss federal statutory rate	54	88	185
Taxes on impairment losses subject to rates different than the Swiss federal statutory rate	(8)	174	5
Taxes on revaluation of Norwegian assets	50	69	—
Taxes on litigation matters subject to rates different than the Swiss federal statutory rate	(9)	5	(33)
Changes in unrecognized tax benefits, net	19	(119)	(62)
Change in valuation allowance	34	93	37
Benefit from foreign tax credits	(10)	(23)	(18)
Other, net	(4)	—	14
Income tax expense	$ 206	$ 146	$ 258

Deferred taxes—The significant components of our deferred tax assets and liabilities were as follows (in millions):

	December 31,	
	2015	2014
Deferred tax assets		
Net operating loss carryforwards	$ 293	$ 315
Tax credit carryforwards	23	14
Accrued payroll expenses not currently deductible	83	113
Deferred income	139	125
Loss contingencies	72	66
Professional fees	2	94
U.K. charter limitation	69	28
Other	36	28
Valuation allowance	(374)	(340)
Total deferred tax assets	343	443
Deferred tax liabilities		
Depreciation and amortization	(332)	(483)
Other	(34)	(37)
Total deferred tax liabilities	(366)	(520)
Net deferred tax liabilities	$ (23)	$ (77)

At December 31, 2015 and 2014, our deferred tax assets included U.S. foreign tax credit carryforwards of $23 million and $14 million, respectively, which will expire between 2017 and 2025. The deferred tax assets related to our net operating losses were generated in various worldwide tax jurisdictions. At December 31, 2015, the tax effect of our Norwegian and Brazilian net operating losses, which do not expire, was $77 million and $17 million, respectively, and the tax effect of our U.S. net operating loss, which expires in 2035 was $42 million. At December 31, 2014, the tax effect of our Norwegian and Brazilian net operating losses, which do not expire, was $108 million and $40 million, respectively.

The valuation allowance for our deferred tax assets was as follows (in millions):

	December 31,	
	2015	2014
Valuation allowance for deferred tax assets	$ 374	$ 340

Our deferred tax liabilities include taxes related to the earnings of certain subsidiaries that are not permanently reinvested or that will not be permanently reinvested in the future. Should our expectations change regarding future tax consequences, we may be required to record additional deferred taxes that could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

We consider the earnings of certain of our subsidiaries to be indefinitely reinvested. As such, we have not provided for taxes on these unremitted earnings. Should we make a distribution from the unremitted earnings of these subsidiaries, we would be subject to taxes payable to various jurisdictions. At December 31, 2015, the amount of indefinitely reinvested earnings was approximately $2.2 billion. If all of these indefinitely reinvested earnings were distributed, we would be subject to estimated taxes of $200 million to $250 million.

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Unrecognized tax benefits—The changes to our liabilities related to unrecognized tax benefits, excluding interest and penalties that we recognize as a component of income tax expense, were as follows (in millions):

	Years ended December 31,		
	2015	2014	2013
Balance, beginning of period	$ 265	$ 326	$ 382
Additions for current year tax positions	36	25	24
Additions for prior year tax positions	24	3	10
Reductions for prior year tax positions	(27)	(19)	(72)
Settlements	(5)	(47)	(6)
Reductions related to statute of limitation expirations	(6)	(23)	(12)
Balance, end of period	$ 287	$ 265	$ 326

The liabilities related to our unrecognized tax benefits, including related interest and penalties that we recognize as a component of income tax expense, were as follows (in millions):

	December 31,	
	2015	2014
Unrecognized tax benefits, excluding interest and penalties	$ 287	$ 265
Interest and penalties	118	120
Unrecognized tax benefits, including interest and penalties	$ 405	$ 385

In the years ended December 31, 2015, 2014 and 2013, we recognized income of $1 million, $57 million and $23 million, respectively, recorded as a component of income tax expense, related to previously recognized interest and penalties associated with our unrecognized tax benefits. As of December 31, 2015, if recognized, $405 million of our unrecognized tax benefits, including interest and penalties, would favorably impact our effective tax rate.

It is reasonably possible that our existing liabilities for unrecognized tax benefits may increase or decrease in the year ending December 31, 2016, primarily due to the progression of open audits and the expiration of statutes of limitation. However, we cannot reasonably estimate a range of potential changes in our existing liabilities for unrecognized tax benefits due to various uncertainties, such as the unresolved nature of various audits.

Tax returns—We file federal and local tax returns in several jurisdictions throughout the world. With few exceptions, we are no longer subject to examinations of our U.S. and non U.S. tax matters for years prior to 2010.

Our tax returns in the major jurisdictions in which we operate, other than the U.S., Norway and Brazil, which are mentioned below, are generally subject to examination for periods ranging from three to six years. We have agreed to extensions beyond the statute of limitations in two major jurisdictions for up to 20 years. 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. While we cannot predict or provide assurance as to the timing or the 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 statement of cash flows.

U.S. tax investigations—In January 2014, we received a draft assessment from the U.S. tax authorities related to our 2010 and 2011 U.S. federal income tax returns. The significant issue raised in the assessment relates to transfer pricing for certain charters of drilling rigs between our subsidiaries. This issue, if successfully challenged, would result in net adjustments of approximately $290 million of additional taxes, excluding interest and penalties. We believe our U.S. federal income tax returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims to the contrary. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Furthermore, if the authorities were to continue to pursue these positions with respect to subsequent years and were successful in such assertions, our effective tax rate on worldwide earnings with respect to years following 2011 could increase substantially, and could have a material adverse effect on our consolidated results of operations or cash flows.

Norway tax investigations and trial—Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 1999, 2001 and 2002 as well as the actions of certain employees of our former external tax advisors on these transactions. At December 31, 2015, outstanding civil tax assessments were as follows: (a) NOK 412 million, equivalent to approximately $47 million, plus interest, related to a 2001 dividend payment and (b) NOK 43 million, equivalent to approximately $5 million, plus interest, related to certain foreign exchange deductions and dividend withholding tax. On June 26, 2014, the Norwegian district court in Oslo ruled that our subsidiary was liable for the civil tax assessment of NOK 412 million, equivalent to approximately $47 million, but waived all penalties and interest. On September 12, 2014, we appealed the ruling. We intend to take all other appropriate action to continue to support our position that our Norwegian tax returns are materially correct as filed.

In June 2011, the Norwegian authorities issued criminal indictments against two of our subsidiaries alleging misleading or incomplete disclosures in Norwegian tax returns for the years 1999 through 2002, as well as inaccuracies in Norwegian statutory financial statements for the years ended December 31, 1996 through 2001. The Norwegian authorities subsequently extended a criminal indictment against a third subsidiary in April 2012. The Norwegian authorities also issued criminal indictments against two employees of our former external tax advisors related to the disclosures in our tax returns, and our former external Norwegian tax attorney related to certain of our restructuring transactions and the 2001 dividend payment. On July 2, 2014, the District Court acquitted all subsidiaries and the employees of our former external tax advisors and our former external Norwegian tax attorney. On July 16, 2014, the Norwegian authorities filed appeals on three criminal charges but formally dropped all claims related to two criminal charges. At December 31, 2015, the outstanding criminal charges were with respect to the following matters: (a) disclosures in our Norwegian tax returns related to a dividend payment in 2001, (b) disclosures in our Norwegian tax returns related to an intercompany rig sale in 1999 and (c) certain inaccuracies in Norwegian statutory financial statements for the years ended December 31, 1996 through 2001. We believe our Norwegian tax returns are materially correct as filed, and we intend to continue to vigorously contest any assertions to the contrary by the Norwegian civil and criminal authorities in connection with the various transactions being investigated. An unfavorable outcome on the Norwegian civil and criminal tax matters could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. See Note 25—Subsequent Events.

Brazil tax investigations—Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. In December 2005, the Brazilian tax authorities issued an aggregate tax assessment of BRL 762 million, equivalent to approximately $192 million, including penalties and interest. On January 25, 2008, we filed a protest letter with the Brazilian tax authorities, and we are currently engaged in the appeals process. On May 19, 2014, with respect to our Brazilian income tax returns for the years 2009 and 2010, the Brazilian tax authorities issued an aggregate tax assessment of BRL 132 million, equivalent to approximately $33 million, including penalties and interest. On June 18, 2014, we filed a protest letter with the Brazilian tax authorities. We believe our returns are materially correct as filed, and we are vigorously contesting these assessments. An unfavorable outcome on these proposed assessments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other 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, employee contribution requirements 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.

Note 7—Discontinued Operations

Summarized results of discontinued operations

The summarized results of operations included in income from discontinued operations were as follows (in millions):

Years ended December 31,

	2015	2014	2013
Operating revenues	$ —	$ 166	$ 1,031
Operating and maintenance expense	(3)	(162)	(1,022)
Loss on impairment of assets in discontinued operations	—	—	(14)
Gain (loss) on disposal of assets in discontinued operations, net	1	(10)	54
Income (loss) from discontinued operations before income tax expense	(2)	(6)	49
Income tax benefit (expense)	4	(14)	(40)
Income (loss) from discontinued operations, net of tax	$ 2	$ (20)	$ 9

Standard jackup and swamp barge contract drilling services

Overview—In September 2012, in connection with our efforts to dispose of non strategic assets and to reduce our exposure to low specification drilling units, we committed to a plan to discontinue operations associated with the standard jackup and swamp barge asset groups, components of our contract drilling services operating segment.

Impairments—In the year ended December 31, 2013, we recognized an aggregate loss of $14 million ($0.04 per diluted share), which had no tax effect, associated with the impairment of the standard jackups GSF Rig 127 and GSF Rig 134. We measured the impairment of the drilling units and related equipment as the amount by which the carrying amounts exceeded the estimated fair values less costs to sell. We estimated the fair value of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including a binding sale and purchase agreement for the drilling units and related equipment.

Sale transactions with Shelf Drilling—In November 2012, we completed the sale of 38 drilling units to Shelf Drilling Holdings, Ltd. ("Shelf Drilling"). A portion of the proceeds from the sale were in the form of perpetual preference shares that had a stated value of $195 million. In June 2013, we sold the preference shares to an unaffiliated party for cash proceeds of $185 million and, in the year ended December 31, 2013, we recognized a loss of $10 million ($0.03 per diluted share), recorded in other expense, net, which had no tax effect, associated with the sale of the preference shares.

For a transition period following the completion of the sale transactions, we agreed to continue to operate a substantial portion of the standard jackups under operating agreements with Shelf Drilling and to provide certain other transition services to Shelf Drilling. Under the operating agreements, we agreed to remit the collections from our customers under the associated drilling contracts to Shelf Drilling, and Shelf Drilling agreed to reimburse us for our direct costs and expenses incurred while operating the standard jackups on behalf of Shelf Drilling with certain exceptions. Amounts due to Shelf Drilling under the operating agreements and transition services agreement may be contractually offset against amounts due from Shelf Drilling. The costs to us for providing such operating and transition services, including allocated indirect costs, exceeded the amounts we received from Shelf Drilling for providing such services.

Under the operating agreements, we agreed to operate the standard jackups on behalf of Shelf Drilling for periods ranging from nine months to 27 months, until expiration or novation of the underlying drilling contracts by Shelf Drilling, the last of which was completed in January 2015. Until the expiration or novation of such drilling contracts, we retained possession of the materials and supplies associated with the standard jackups that we operated under the operating agreements. In the years ended December 31, 2015, 2014 and 2013, we received cash proceeds of $3 million, $25 million and $64 million, respectively, associated with the sale of equipment and materials and supplies to Shelf Drilling upon expiration of the drilling contracts. In the year ended December 31, 2013, we recognized a net gain of $11 million ($0.03 per diluted share), which had no tax effect, associated with the sale of equipment and materials and supplies to Shelf Drilling upon expiration or novation of the drilling contracts.

For a period through November 2015, we agreed to provide to Shelf Drilling up to $125 million of financial support by maintaining letters of credit, surety bonds and guarantees for various contract bidding and performance activities associated with the drilling units sold to Shelf Drilling and in effect at the closing of the sale transactions. In November 2015, our commitment to provide such financial support expired, and at December 31, 2015, we had no remaining letters of credit outstanding in support of drilling units sold to Shelf Drilling. At December 31, 2014, we had $91 million of outstanding letters of credit, issued under our committed and uncommitted credit lines, in support of drilling units sold to Shelf Drilling. See Note 14—Commitments and Contingencies.

Other dispositions—During the year ended December 31, 2013, we completed the sale of the standard jackups D.R. Stewart, GSF Adriatic VIII, GSF Rig 127, GSF Rig 134, Interocean III, Trident IV A and Trident VI, along with related equipment. In the year ended December 31, 2013, in connection with the disposal of these assets, we received aggregate net cash proceeds of $140 million and recognized an aggregate net gain of $44 million ($0.12 per diluted share), which had no tax effect. In the years ended December 31, 2015, 2014 and 2013, we recognized an aggregate net gain of $1 million and $2 million and an aggregate net loss of $1 million, respectively, associated with the disposal of assets unrelated to rig sales.

Drilling management services

In February 2014, in connection with our efforts to discontinue non strategic operations, we completed the sale of ADTI, which performs drilling management services in the North Sea. As a result of the sale, we reclassified the results of operations of our drilling management services operating segment to discontinued operations for all periods presented. In the year ended December 31, 2014, we received net cash proceeds of $10 million and recognized a net loss of $12 million ($0.03 per diluted share), which had no tax effect, associated with the sale of the drilling management services business. We agreed to provide a $15 million working capital line of credit to the buyer through March 2016. At December 31, 2014, ADTI owed to us borrowings of $15 million outstanding under the working capital line of credit, recorded in other assets. In May 2015, ADTI repaid the borrowings and terminated the credit agreement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Note 8—Earnings (Loss) Per Share

The numerator and denominator used for the computation of basic and diluted per share earnings from continuing operations were as follows (in millions, except per share data):

	Years ended December 31,					
	2015		2014		2013	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
Numerator for earnings (loss) per share						
Income (loss) from continuing operations attributable to controlling interest	$ 789	$ 789	$ (1,893)	$ (1,893)	$ 1,398	$ 1,398
Undistributed earnings allocable to participating securities	(7)	(7)	—	—	(12)	(12)
Income (loss) from continuing operations available to shareholders	$ 782	$ 782	$ (1,893)	$ (1,893)	$ 1,386	$ 1,386
Denominator for earnings (loss) per share						
Weighted-average shares outstanding	363	363	362	362	360	360
Effect of stock options and other share-based awards	—	—	—	—	—	—
Weighted-average shares for per share calculation	363	363	362	362	360	360
Per share earnings (loss) from continuing operations	$ 2.16	$ 2.16	$ (5.23)	$ (5.23)	$ 3.85	$ 3.85

In the years ended December 31, 2015, 2014 and 2013, we excluded from the calculation 3.3 million, 2.5 million and 1.4 million share based awards, respectively, since the effect would have been anti dilutive.

Note 9—Drilling Fleet

Construction work in progress—For each of the three years ended December 31, 2015, the changes in our construction work in progress, including capital expenditures and other capital additions, such as capitalized interest, were as follows (in millions):

	Years ended December 31,		
	2015	2014	2013
Construction work in progress, at beginning of period	$ 2,451	$ 2,710	$ 2,010
Capital additions			
Newbuild construction program	1,622	1,436	1,379
Other equipment and construction projects	379	729	859

Total capital expenditures	2,001	2,165	2,238
Changes in accrued capital additions	(15)	(43)	44
Impairment of construction work in progress	(52)	—	(17)
Property and equipment placed into service			
Newbuild construction program	—	(1,522)	(720)
Other property and equipment	(649)	(859)	(845)
Construction work in progress, at end of period	$ 3,736	$ 2,451	$ 2,710

Dispositions—During the year ended December 31, 2015, in connection with our efforts to dispose of non strategic assets, we completed the sale of the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Discoverer Seven Seas, GSF Celtic Sea, Sedco 707, Sedco 710, Sovereign Explorer and Transocean Rather and the midwater floaters C. Kirk Rhein, Jr., GSF Aleutian Key, GSF Arctic I, GSF Arctic III, J.W. McLean, Sedco 601, Sedco 700, Transocean Amirante and Transocean Legend, along with related equipment. In the year ended December 31, 2015, we received aggregate net cash proceeds of $35 million and recognized an aggregate net gain of $14 million ($11 million or $0.02 per diluted share, net of tax) associated with the disposal of these assets. In the year ended December 31, 2015, we received cash proceeds of $16 million and recognized an aggregate net loss of $42 million associated with the disposal of assets unrelated to rig sales.

During the year ended December 31, 2014, we completed the sale of the deepwater floater Sedco 709, the midwater floater Sedco 703 and the high specification jackups GSF Magellan and GSF Monitor, along with related equipment. In the year ended December 31, 2014, we received aggregate net cash proceeds of $185 million and recognized an aggregate net loss of $1 million associated with the disposal of these assets. In the year ended December 31, 2014, we received cash proceeds of $30 million and recognized an aggregate net loss of $25 million associated with the disposal of assets unrelated to rig sales.

During the year ended December 31, 2013, we completed the sale of the deepwater floater Transocean Richardson along with related equipment. In the year ended December 31, 2013, we received net cash proceeds of $142 million and recognized a net gain of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

$33 million ($22 million or $0.06 per diluted share, net of tax) associated with the disposal of these assets. In the year ended December 31, 2013, we received cash proceeds of $32 million and recognized an aggregate net loss of $26 million associated with the disposal of assets unrelated to rig sales.

During the year ended December 31, 2015, we committed to a plan to sell the ultra deepwater floaters Deepwater Expedition and GSF Explorer, the deepwater floaters Deepwater Navigator, GSF Celtic Sea, Sedco 707, and Transocean Rather and the midwater floaters GSF Aleutian Key, GSF Arctic III, GSF Grand Banks, GSF Rig 135, Transocean Amirante and Transocean Legend, along with related equipment. At December 31, 2015, the aggregate carrying amount of our assets held for sale was $8 million, including the deepwater floater Deepwater Navigator and the midwater floaters Falcon 100, GSF Grand Banks, GSF Rig 135 and Sedneth 701, along with related equipment, and certain corporate assets. At December 31, 2014, the aggregate carrying amount of our assets held for sale was $25 million, including an aggregate carrying amount of $23 million for the deepwater floaters Discoverer Seven Seas, Sedco 710 and Sovereign Explorer and the midwater floaters C. Kirk Rhein, Jr., Falcon 100, GSF Arctic I, J.W. McLean, Sedco 601, Sedco 700 and Sedneth 701, along with related equipment, and an aggregate carrying amount of $2 million for the then remaining assets associated with our discontinued operations.

See Note 5—Impairments.

Note 10—Intangible Liabilities

The gross carrying amounts of our drilling contract intangibles which we consider to be finite lived intangible liabilities, and accumulated amortization were as follows (in millions):

	Year ended December 31, 2015			Year ended December 31, 2014		
	Gross carrying amount	Accumulated amortization	Net carrying amount	Gross carrying amount	Accumulated amortization	Net carrying amount
Drilling contract intangible liabilities						
Balance, beginning of period	$ 1,410	$ (1,381)	$ 29	$ 1,410	$ (1,366)	$ 44
Amortization	—	(15)	(15)	—	(15)	(15)
Balance, end of period	$ 1,410	$ (1,396)	$ 14	$ 1,410	$ (1,381)	$ 29

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Note 11—Debt

Debt, net of debt related balances, including unamortized discounts, premiums, issue costs and fair value adjustments, was comprised of the following (in millions):

	December 31, 2015	December 31, 2014
4.95% Senior Notes due November 2015 (a)	$ —	$ 897
5.05% Senior Notes due December 2016 (a)	973	996
2.5% Senior Notes due October 2017 (a)	568	745
Eksportfinans Loans due January 2018	216	369
6.00% Senior Notes due March 2018 (a)	789	998
7.375% Senior Notes due April 2018 (a)	236	246
6.50% Senior Notes due November 2020 (a)	911	906
6.375% Senior Notes due December 2021 (a)	1,143	1,192
3.8% Senior Notes due October 2022 (a)	726	740
7.45% Notes due April 2027 (a)	94	97
8% Debentures due April 2027 (a)	57	57
7% Notes due June 2028	309	309
Capital lease contract due August 2029	591	615
7.5% Notes due April 2031 (a)	589	596
6.80% Senior Notes due March 2038 (a)	991	991
7.35% Senior Notes due December 2041 (a)	297	297
Total debt	8,490	10,051
Less debt due within one year		
4.95% Senior Notes due November 2015 (a)	—	897
5.05% Senior Notes due December 2016 (a)	973	—
Eksportfinans Loans due January 2018	97	114
Capital lease contract due August 2029	23	21
Total debt due within one year	1,093	1,032
Total long-term debt	$ 7,397	$ 9,019

(a) Transocean Inc., a 100 percent owned subsidiary of Transocean Ltd., is the issuer of the notes and debentures, which have been guaranteed by Transocean Ltd. Transocean Ltd. has also guaranteed borrowings under the Five Year Revolving Credit Facility. Transocean Ltd. and Transocean Inc. are not subject to any significant restrictions on their ability to obtain funds from their consolidated subsidiaries by dividends, loans or return of capital distributions. See Note 23—Condensed Consolidating Financial Information.

Scheduled maturities—At December 31, 2015, the scheduled maturities of our debt were as follows (in millions):

	Consolidated total

Years ending December 31,		
2016	$	1,089
2017		686
2018		1,095
2019		32
2020		935
Thereafter		4,672
Total debt, excluding debt-related balances		8,509
Total debt-related balances, net		(19)
Total debt	$	8,490

Five Year 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. Borrowings under the Five Year Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default, borrowings are guaranteed by Transocean Ltd. and may be prepaid in whole or in part without premium or penalty.

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 credit rating of our non credit enhanced senior unsecured long term debt (“Debt Rating”), or (2) the base rate specified in the credit agreement plus the

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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 depending on our Debt Rating. Effective March 19, 2015, as a result of a reduction of our Debt Rating, the Five Year Revolving Credit Facility Margin increased to 1.75 percent from 1.5 percent and the facility fee increased to 0.275 percent from 0.225 percent. At December 31, 2015, based on our Debt Rating on that date, the Five Year Revolving Credit Facility Margin was 1.75 percent and the facility fee was 0.275 percent. At December 31, 2015, we had no borrowings outstanding or letters of credit issued, and we had $3.0 billion of available borrowing capacity under the Five Year Revolving Credit Facility.

4.95% Senior Notes and 6.50% Senior Notes—In September 2010, we issued $1.1 billion aggregate principal amount of 4.95% Senior Notes due November 2015 (the “4.95% Senior Notes”) and $900 million aggregate principal amount of 6.50% Senior Notes due November 2020 (the “6.50% Senior Notes,” and together with the 4.95% Senior Notes, the “2010 Senior Notes”). We are required to pay interest on the 2010 Senior Notes on May 15 and November 15 of each year, beginning November 15, 2010. We may redeem some or all of the 2010 Senior Notes at any time at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make whole premium. The indenture pursuant to which the 2010 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions.

On November 17, 2014, we redeemed an aggregate principal amount of $207 million of the outstanding 4.95% Senior Notes with an aggregate payment of $216 million and we recognized a loss of $9 million associated with the partial redemption. On July 30, 2015, we redeemed the remaining aggregate principal amount of $893 million of the outstanding 4.95% Senior Notes with an aggregate cash payment of $904 million, and in the year ended December 31, 2015, we recognized a loss of $10 million associated with the retirement. At December 31, 2015 and 2014, the aggregate outstanding principal amount of the 6.50% Senior Notes was $900 million.

5.05% Senior Notes, 6.375% Senior Notes and 7.35% Senior Notes—In December 2011, we issued $1.0 billion aggregate principal amount of 5.05% Senior Notes due December 2016 (the “5.05% Senior Notes”), $1.2 billion aggregate principal amount of 6.375% Senior Notes due December 2021 (the “6.375% Senior Notes”) and $300 million aggregate principal amount of 7.35% Senior Notes due December 2041 (the “7.35% Senior Notes,” and collectively with the 5.05% Senior Notes and the 6.375% Senior Notes, the “2011 Senior Notes”). The interest rates for the notes are subject to adjustment from time to time upon a change to our Debt Rating. Effective June 15 and December 15, 2015, as a result of reductions of our Debt Rating, the interest rates on the 5.05% Senior Notes, the 6.375% Senior Notes and the 7.35% Senior Notes increased by an incremental 0.5 percent and 0.25 percent, respectively, from the stated rate to 5.80 percent, 7.125 percent and 8.10 percent, respectively. The indenture pursuant to which the 2011 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. We may redeem some or all of the 2011 Senior Notes at any time at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make whole premium.

In the year ended December 31, 2015, we repurchased an aggregate principal amount of $25 million of the 5.05% Senior Notes and $50 million of the 6.375% Senior Notes with aggregate cash payments of $25 million and $40 million, respectively, and recognized a gain of less than $1 million and $10 million, respectively, associated with the retirement of debt. At December 31, 2015, the aggregate outstanding principal amount of the 5.05% Senior Notes, the 6.375% Senior Notes and the 7.35% Senior Notes was $975 million, $1.2 billion and $300 million, respectively.

2.5% Senior Notes and 3.8% Senior Notes—In September 2012, we issued $750 million aggregate principal amount of 2.5% Senior Notes due October 2017 (the "2.5% Senior Notes") and $750 million aggregate principal amount of 3.8% Senior Notes due October 2022 (the "3.8% Senior Notes," and together with the 2.5% Senior Notes, the "2012 Senior Notes"). The interest rates for the notes are subject to adjustment from time to time upon a change to our Debt Rating. Effective April 15, 2015, as a result of a reduction of our Debt Rating, the interest rates on the 2.5% Senior Notes and the 3.8% Senior Notes increased 0.5 percent from the stated rate to 3.0 percent and 4.3 percent, respectively. The indenture pursuant to which the 2012 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. We may redeem some or all of the 2012 Senior Notes at any time prior to maturity at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, together with a make whole premium unless, in the case of the 3.8% Senior Notes, such redemption occurs on or after July 15, 2022, in which case no such make whole premium will apply.

In the year ended December 31, 2015, we repurchased an aggregate principal amount of $180 million of the 2.5% Senior Notes and $16 million of the 3.8% Senior Notes with an aggregate cash payment of $170 million and $11 million, respectively, and recognized an aggregate gain of $9 million and $5 million, respectively, associated with the retirement of debt. At December 31, 2015, the aggregate outstanding principal amount of the 2.5% Senior Notes and the 3.8% Senior Notes was $570 million and $734 million, respectively.

5.25% Senior Notes, 6.00% Senior Notes and 6.80% Senior Notes—In December 2007, we issued $500 million aggregate principal amount of 5.25% Senior Notes due March 2013 (the "5.25% Senior Notes"), $1.0 billion aggregate principal amount of 6.00% Senior Notes due March 2018 (the "6.00% Senior Notes") and $1.0 billion aggregate principal amount of 6.80% Senior Notes due March 2038 (the "6.80% Senior Notes"). The indenture pursuant to which the notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. We may redeem some or all of the notes at any time, at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make whole premium.

In the year ended December 31, 2015, we repurchased an aggregate principal amount of $211 million of the 6.00% Senior Notes with an aggregate cash payment of $205 million and recognized an aggregate gain of $5 million associated with the retirement of debt. On March 15, 2013, the stated maturity date of the 5.25% Senior Notes, we repaid the outstanding $500 million aggregate principal amount of the 5.25% Senior Notes. At December 31, 2015, the aggregate outstanding principal amount of the 6.00% Senior Notes and the 6.80% Senior Notes was $789 million and $1.0 billion, respectively.

Eksportfinans Loans—We have borrowings under the Loan Agreement dated September 12, 2008 ("Eksportfinans Loan A") and under the Loan Agreement dated November 18, 2008 ("Eksportfinans Loan B," and together with Eksportfinans Loan A, the "Eksportfinans Loans"). The Eksportfinans Loans bear interest at a fixed rate of 4.15 percent and require semi annual installments of principal and interest through September 2017 and January 2018 for Eksportfinans Loan A and Eksportfinans Loan B, respectively. At December 31, 2015 and 2014, the aggregate principal amount outstanding under the Eksportfinans Loans was NOK 1.9 billion and NOK 2.8 billion, equivalent to approximately $217 million and $370 million, respectively.

The Eksportfinans Loans require collateral to be held by a financial institution through expiration (the "Eksportfinans Restricted Cash Investments"). The Eksportfinans Restricted Cash Investments bear interest at a fixed rate of 4.15 percent with semi annual installments that correspond with those of the Eksportfinans Loans. At December 31, 2015 and 2014, the aggregate principal amount of the Eksportfinans Restricted Cash Investments was NOK 1.9 billion and NOK 2.8 billion, equivalent to approximately $217 million and $370 million, respectively.

7.375% Senior Notes—In March 2002, we issued $247 million principal amount of our 7.375% Senior Notes due April 2018 (the "7.375% Senior Notes"). The indenture pursuant to which the 7.375% Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. In the year ended December 31, 2015, we repurchased an aggregate principal amount of $10 million of the 7.375% Senior Notes with an aggregate cash payment of $9 million and recognized an aggregate gain of $1 million associated with the retirement of debt. At December 31, 2015, the aggregate outstanding principal amount of the 7.375% Senior Notes was $236 million.

7.45% Notes and 8% Debentures—In April 1997, a predecessor of Transocean Inc. issued $100 million aggregate principal amount of 7.45% Notes due April 2027 (the "7.45% Notes") and $200 million aggregate principal amount of 8% Debentures due April 2027 (the "8% Debentures"). The indenture pursuant to which the 7.45% Notes and the 8% Debentures were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. The 7.45% Notes and the 8% Debentures are redeemable at any time at our option subject to a make whole premium. In the year ended December 31, 2015, we repurchased an aggregate principal amount of $4 million of the 7.45% Senior Notes with an aggregate cash payment of $3 million and recognized an aggregate gain of $1 million associated with the retirement of debt. At December 31, 2015, the aggregate outstanding principal amount of the 7.45% Notes and the 8% Debentures was $96 million and $57 million, respectively.

7% Notes—One of our wholly owned subsidiaries is the obligor of the 7% Notes due 2028 (the "7% Notes"), and we have not guaranteed this obligation. The indenture related to the 7% Notes contains limitations on creating liens and sale/leaseback transactions. The obligor may redeem the 7% Notes in whole or in part at a price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make whole premium. At December 31, 2015, the outstanding principal amount of the 7% Notes was $300 million.

Capital lease contract—In August 2009, we accepted delivery of Petrobras 10000, an asset held under capital lease, and we recorded $716 million to property and equipment, net and a corresponding increase to long term debt. The capital lease contract has an implicit interest rate of 7.8 percent and requires scheduled monthly payments of $6 million through August 2029, after which we will have the right and obligation to acquire the drillship from the lessor for one dollar. See Note 14—Commitments and Contingencies.

7.5% Notes—In April 2001, we issued $600 million aggregate principal amount of 7.5% Notes due April 2031 (the "7.5% Notes"). The indenture pursuant to which the notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. In the year ended December 31, 2015, we repurchased an aggregate principal amount of $7 million of the 7.5% Senior Notes with an aggregate payment of $5 million and recognized an aggregate gain of $2 million associated with the retirement of debt. At December 31, 2015, the outstanding principal amount of the 7.5% Notes was $593 million.

ADDCL Credit Facility—ADDCL had a $704 million senior secured credit facility, established under a bank credit agreement dated June 2, 2008 that was scheduled to expire in December 2017 (the "ADDCL Credit Facility"), for which one of our subsidiaries provided the portion of the commitment for the facility. In February 2014, we made a cash payment of $614 million to repay the borrowings outstanding under the ADDCL Credit Facility, $451 million of which was paid to one of our subsidiaries and eliminated in consolidation. Upon repayment of all borrowings, we terminated the bank credit agreement under which the credit facility was established.

1.50% Series C Convertible Senior Notes—In December 2007, we issued $2.2 billion aggregate principal amount of the 1.50% Series C Convertible Senior Notes due December 2037 (the "Convertible Senior Notes"). On December 14, 2012, certain holders of the Series C Convertible Senior Notes exercised their option to require us to repurchase all or any part of such holders' notes, and as a result, we were required to repurchase an aggregate principal amount of $1.7 billion of the Series C Convertible Senior Notes for an aggregate cash payment of $1.7 billion. In February 2013, we redeemed the remaining $62 million aggregate principal amount of the Series C Convertible Senior Notes for an aggregate cash payment of $62 million.

Callable Bonds—We were the obligor for the FRN Aker Drilling ASA Senior Unsecured Callable Bond Issue 2011/2016 and the 11% Aker Drilling ASA Senior Unsecured Callable Bond Issue 2011/2016 (together, the "Callable Bonds"), which were publicly traded on the Oslo Stock Exchange. In March 2013, we made an aggregate cash payment of NOK 1,567 million, equivalent to $273 million, to redeem the aggregate outstanding principal amount of NOK 1,500 million, equivalent to $262 million. In the year ended December 31, 2013, we recognized a loss of $1 million associated with the retirement of debt.

TPDI Credit Facility—Transocean Pacific Drilling Inc. ("TPDI"), our wholly owned subsidiary, had a $1.265 billion secured credit facility, established under a bank credit agreement dated October 28, 2008, that was scheduled to expire in March 2015 (the "TPDI Credit Facility"), for which one of our subsidiaries provided a portion of the commitment for the facility. In June 2013, we made a cash payment of $735 million to repay the borrowings outstanding under the TPDI Credit Facility, $367 million of which was paid to one of our subsidiaries and eliminated in consolidation. Upon repayment of all borrowings, we terminated the bank credit agreement under which the credit facility was established and the related security agreement. In the year ended December 31, 2013, we recognized a loss of $1 million associated with the retirement of debt.

Note 12—Derivatives and Hedging

Derivatives designated as hedging instruments—During the year ended December 31, 2014, we entered into interest rate swaps, which are designated and qualify as a fair value hedge, to reduce our exposure to changes in the fair value of the 6.0% Senior Notes due March 2018 and the 6.5% Senior Notes due November 2020. The interest rate swaps have aggregate notional amounts equal to the corresponding face values of the hedged instruments and have stated maturities that coincide with those of the hedged instruments. We have determined that the hedging relationships qualify for, and we have applied, the shortcut method of accounting under which the interest rate swaps are considered to have no ineffectiveness and no ongoing assessment of effectiveness is required. Accordingly, changes in the fair value of the interest rate swaps recognized in interest expense offset the changes in the fair value of the hedged fixed rate notes. During the year ended December 31, 2015, we terminated the interest rate swaps previously designated as a fair value hedge of the 6.5% Senior Notes, and we received an aggregate net cash payment of $24 million in connection with the settlement.

At December 31, 2015, the aggregate notional amounts and the weighted average interest rates associated with our derivatives designated as hedging instruments were as follows (in millions, except weighted average rates):

	Pay			Receive		
	Aggregate notional amount	Fixed or variable rate	Weighted average rate	Aggregate notional amount	Fixed or variable rate	Weighted average rate
Interest rate swaps, fair value hedge	$ 750	Variable	5.09 %	$ 750	Fixed	6 %

At December 31, 2015 and 2014, the aggregate carrying amount of our derivatives designated as fair value hedges, measured at fair value and excluding accrued interest, was $2 million and $11 million, respectively, recorded in other assets. See Note 23—Subsequent Events.

We previously had interest rate swaps, which were designated and qualified as a cash flow hedge, to reduce the variability of cash interest payments associated with the variable rate borrowings under the TPDI Credit Facility. In June 2013, we repaid the borrowings under the TPDI Credit Facility, and we terminated these interest rate swaps. In the year ended December 31, 2013, we recognized a loss of $4 million, recorded in interest expense, net of capitalized amounts, associated with the effective portion of the cash flow hedges. In connection with the termination, we recognized a loss of $14 million, recorded in other, net, including $9 million that we reclassified from accumulated other comprehensive loss, and we made a net cash payment of $22 million.

Additionally, we had cross currency interest rate swaps, which were designated and qualified as a cash flow hedge, to reduce the variability of the cash interest payments and the final cash principal payment associated with the Callable Bonds resulting from the changes in the U.S. dollar to Norwegian krone exchange rate. In March 2013, in connection with our redemption of the Callable Bonds, we terminated these cross currency interest rate swaps and the related security agreement. As a result of the termination, in the year ended December 31, 2013, we made a cash payment of $128 million, we received a cash payment of NOK 705 million, which we applied to the redemption of the Callable Bonds, and we reclassified $5 million from accumulated other comprehensive loss to other expense, net.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Note 13—Postemployment Benefit Plans

Defined benefit pension plans and other postretirement employee benefit plans

Overview—In connection with actions taken by us in the year ended December 31, 2015, benefits under all of our remaining U.S. defined benefit pension plans had ceased accruing or were scheduled to cease accruing by March 31, 2016. We will continue to maintain the respective pension obligations under such plans until they have been fully satisfied. As of December 31, 2015, we maintained one funded qualified benefit plan, which primarily covers employees on the U.S. payroll that work outside of the U.S., that will cease to accrue benefits, effective March 31, 2016. Effective January 1, 2015, we formalized amendments to cease accruing benefits under our funded qualified defined benefit pension plan, which previously covered substantially all of our U.S. employees, and a supplemental benefit plan, which previously provided certain eligible employees with benefits in excess of those allowed under the funded qualified defined benefit pension plan. We also maintain one funded and two unfunded defined benefit plans that had previously ceased accruing benefits. We refer to these plans, collectively, as the "U.S. Plans."

As of December 31, 2015, we maintain a defined benefit plan in the U.K. (the "U.K. Plan"), which covers certain current and former employees in the U.K. (see Note 25—Subsequent Events). We also maintain six 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"). Additionally, we maintain certain unfunded defined benefit plans that provide retirement and severance benefits for certain eligible Nigerian and Indonesian employees. We also maintained an end of service benefit plan for certain eligible Egyptian employees, for which we have satisfied all obligations in the year ended December 31, 2015. We refer to the U.K. Plan, the Norway Plans and the plans in Nigeria, Indonesia and Egypt, 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 have several unfunded contributory and noncontributory other postretirement employee benefit plans (the "OPEB Plans") covering substantially all of our U.S. employees. On August 25, 2015, we announced amendments to our OPEB Plans that provide for declining benefits to eligible participants during a phase out period ending December 31, 2025.

Assumptions—We estimated our benefit obligations using the following weighted average assumptions:

	December 31, 2015			December 31, 2014		
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans
Discount rate	4.55 %	3.59 %	3.13 %	4.15 %	3.13 %	3.86 %
Compensation trend rate	3.82 %	3.77 %	n/a	3.82 %	3.72 %	n/a

We estimated our net periodic benefit costs using the following weighted average assumptions:

Year ended December 31, 2015			Year ended December 31, 2014			Year ended December 31, 2013	
U.S.	Non-U.S.	OPEB	U.S.	Non-U.S.	OPEB	U.S.	Non-U.S.

	Plans	Plans	Plans	Plans	Plans	Plans	Plans	Plans	OPEB Plans
Discount rate	4.16 %	3.26 %	3.86 %	5.04 %	4.41 %	4.54 %	4.19 %	5.13 %	3.39 %
Expected rate of return	7.79 %	5.93 %	n/a	7.18 %	6.07 %	n/a	7.48 %	5.79 %	n/a
Compensation trend rate	0.21 %	3.83 %	n/a	4.13 %	4.25 %	n/a	4.22 %	4.21 %	n/a
Health care cost trend rate									
-initial	n/a	n/a	7.81 %	n/a	n/a	7.81 %	n/a	n/a	8.07 %
-ultimate	n/a	n/a	5.00 %	n/a	n/a	5.00 %	n/a	n/a	5.00 %
-ultimate year	n/a	n/a	2023	n/a	n/a	2020	n/a	n/a	2020

"n/a" means not applicable.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Funded status—The changes in projected benefit obligation, plan assets and funded status and the amounts recognized on our consolidated balance sheets were as follows (in millions):

	Year ended December 31, 2015				Year ended December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Change in projected benefit obligation								
Projected benefit obligation, beginning of period	$ 1,592	$ 629	$ 59	$ 2,280	$ 1,380	$ 573	$ 53	$ 2,006
Actuarial (gains) losses, net	(71)	(83)	—	(154)	343	103	5	451
Service cost	5	26	1	32	39	29	1	69
Interest cost	65	19	2	86	64	27	2	93
Plan amendments	—	—	(33)	(33)	—	—	—	—
Currency exchange rate changes	—	(48)	—	(48)	—	(57)	—	(57)
Benefits paid	(65)	(44)	(8)	(117)	(48)	(48)	(4)	(100)
Participant contributions	—	1	3	4	—	1	2	3
Special termination benefits	—	—	—	—	1	—	—	1
Settlements and curtailments	(3)	2	—	(1)	(187)	1	—	(186)
Projected benefit obligation, end of period	1,523	502	24	2,049	1,592	629	59	2,280
Change in plan assets								
Fair value of plan assets, beginning of period	1,271	488	—	1,759	1,116	481	—	1,597
Actual return on plan assets	(21)	12	—	(9)	160	37	—	197
Currency exchange rate changes	—	(39)	—	(39)	—	(39)	—	(39)
Employer contributions	13	21	5	39	43	56	2	101
Participant contributions	—	1	3	4	—	1	2	3
Benefits paid	(65)	(44)	(8)	(117)	(48)	(48)	(4)	(100)
Fair value of plan assets, end of period	1,198	439	—	1,637	1,271	488	—	1,759

Funded status, end of period	$ (325)	$ (63)	$ (24)	$ (412)	$ (321)	$ (141)	$ (59)	$ (521)
Balance sheet classification, end of period:								
Pension asset, non-current	$ —	$ 2	$ —	$ 2	$ —	$ —	$ —	$ —
Accrued pension liability, current	(3)	(3)	(3)	(9)	(3)	—	(4)	(7)
Accrued pension liability, non-current	(322)	(62)	(21)	(405)	(318)	(141)	(55)	(514)
Accumulated other comprehensive income (loss) (a)	(281)	(119)	25	(375)	(261)	(199)	(4)	(464)

(a) Amounts are before income tax effect.

The aggregate projected benefit obligation and fair value of plan assets for plans with a projected benefit obligation in excess of plan assets were as follows (in millions):

	December 31, 2015				December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Projected benefit obligation	$ 1,523	$ 502	$ 24	$ 2,049	$ 1,592	$ 629	$ 59	$ 2,280
Fair value of plan assets	1,198	439	—	1,637	1,271	488	—	1,759

At December 31, 2015 and 2014, the accumulated benefit obligation for all defined benefit pension plans was $2.0 billion and $2.1 billion, respectively. The aggregate accumulated benefit obligation and fair value of plan assets for plans with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	December 31, 2015				December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Accumulated benefit obligation	$ 1,523	$ 374	$ 24	$ 1,921	$ 1,588	$ 553	$ 59	$ 2,200
Fair value of plan assets	1,198	352	—	1,550	1,271	488	—	1,759

Plan assets—We periodically review our investment policies, plan assets and asset allocation strategies to evaluate performance relative to specified objectives. In determining our asset allocation strategies for the U.S. Plans, we review the results of regression models to assess the most appropriate target allocation for each plan, given the plan's status, demographics and duration. For the U.K. Plan, the plan trustees establish the asset allocation strategies consistent with the regulations of the U.K. pension regulators and in consultation with financial advisors and company representatives. Investment managers for the U.S. Plans and the U.K. Plan are given established ranges within which the investments may deviate from the target allocations. For the Norway Plans, we establish minimum rates of return under the terms of investment contracts with insurance companies.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

As of December 31, 2015 and 2014, the weighted average target and actual allocations of the investments for our funded Transocean Plans were as follows:

	December 31, 2015				December 31, 2014			
	Target allocation		Actual allocation		Target allocation		Actual allocation	
	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans
Equity securities	50 %	56 %	47 %	49 %	50 %	53 %	49 %	52 %
Fixed income securities	50 %	16 %	52 %	26 %	50 %	15 %	51 %	19 %
Other investments	—	28 %	1 %	25 %	—	32 %	—	29 %
Total	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

As of December 31, 2015, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2015								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Mutual funds									
U.S. equity funds	$ 459	$ —	$ 459	$ —	$ 36	$ 36	$ 459	$ 36	$ 495
Non-U.S. equity funds	104	2	106	3	179	182	107	181	288
Bond funds	626	—	626	—	115	115	626	115	741
Total mutual funds	1,189	2	1,191	3	330	333	1,192	332	1,524
Other investments									
Cash and money market funds	6	—	6	—	—	—	6	—	6
Property collective trusts	—	—	—	—	20	20	—	20	20
Investment contracts	—	—	—	—	87	87	—	87	87

Total other investments	6	—	6	—	107	107	6	107	113
Total investments	$ 1,195	$ 2	$ 1,197	$ 3	$ 437	$ 440	$ 1,198	$ 439	$ 1,637

As of December 31, 2014, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2014								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Mutual funds									
U.S. equity funds	$ 500	$ —	$ 500	$ —	$ 43	$ 43	$ 500	$ 43	$ 543
Non-U.S. equity funds	113	—	113	3	211	214	116	211	327
Bond funds	651	—	651	—	94	94	651	94	745
Total mutual funds	1,264	—	1,264	3	348	351	1,267	348	1,615
Other investments									
Cash and money market funds	4	3	7	—	—	—	4	3	7
Property collective trusts	—	—	—	—	19	19	—	19	19
Investment contracts	—	—	—	—	118	118	—	118	118
Total other investments	4	3	7	—	137	137	4	140	144
Total investments	$ 1,268	$ 3	$ 1,271	$ 3	$ 485	$ 488	$ 1,271	$ 488	$ 1,759

The U.S. Plans and the U.K. Plan invest primarily in passively managed funds that reference market indices. The funded Norway Plans are subject to contractual terms under selected insurance programs. Each plan's investment managers have discretion to select the securities held within each asset category. Given this discretion, the managers may occasionally invest in our debt or equity securities, and may hold either long or short positions in such securities. As the plan investment managers are required to maintain well diversified portfolios, the actual investment in our securities would be immaterial relative to asset categories and the overall plan assets.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Net periodic benefit costs—Net periodic benefit costs, before tax, included the following components (in millions):

	Year ended December 31, 2015			Year ended December 31, 2014			Year ended December 31, 2013		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Service cost	$ 5	$ 26	$ 31	$ 39	$ 29	$ 68	$ 55	$ 27	$ 82
Interest cost	65	19	84	64	27	91	63	25	88
Expected return on plan assets	(87)	(28)	(115)	(75)	(28)	(103)	(70)	(25)	(95)
Settlements and curtailments	3	2	5	(7)	3	(4)	2	3	5
Special termination benefits	—	—	—	—	—	—	1	—	1
Actuarial losses, net	11	11	22	17	5	22	45	3	48
Prior service cost, net	—	—	—	(1)	—	(1)	(1)	1	—
Net periodic benefit costs	$ (3)	$ 30	$ 27	$ 37	$ 36	$ 73	$ 95	$ 34	$ 129

In September and December 2014, we recognized settlement and curtailment charges for two of our unfunded Non U.S. Plans in Nigeria and Egypt associated with certain employee terminations.

In the years ended December 31, 2015, 2014 and 2013, for the OPEB Plans, the combined components of net periodic benefit costs, including service cost, interest cost, recognized net actuarial losses, prior service cost amortization, curtailments and special termination benefits were $(1) million, $2 million and $3 million, respectively.

The following table presents the amounts in accumulated other comprehensive income (loss), before tax, that have not been recognized as components of net periodic benefit costs (in millions):

	December 31, 2015				December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ (281)	$ (119)	$ (6)	$ (406)	$ (261)	$ (199)	$ (5)	$ (465)
Prior service cost, net	—	—	31	31	—	—	1	1
Total	$ (281)	$ (119)	$ 25	$ (375)	$ (261)	$ (199)	$ (4)	$ (464)

The following table presents the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit costs during the year ending December 31, 2016 (in millions):

	Year ending December 31, 2016			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ 4	$ 2	$ —	$ 6
Prior service cost, net	—	—	(3)	(3)
Total amount expected to be recognized	$ 4	$ 2	$ (3)	$ 3

Funding contributions—In the years ended December 31, 2015, 2014 and 2013, we made an aggregate contribution of $39 million, $101 million and $115 million, respectively, to the Transocean Plans and the OPEB Plans using our cash flows from operations. In the year ending December 31, 2016, we expect to contribute $52 million to the Transocean Plans, and we expect to fund benefit payments of approximately $3 million for the OPEB Plans as costs are incurred.

Benefit payments—The following were the projected benefits payments (in millions):

	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Years ending December 31,				
2016	$ 58	$ 12	$ 3	$ 73
2017	62	9	3	74
2018	66	9	3	78
2019	70	10	3	83
2020	73	11	3	87
2021 - 2025	407	88	12	507

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Defined contribution plans

At December 31, 2015, we sponsored three defined contribution plans, including (1) a qualified defined contribution savings plan covering certain employees working in the U.S. (the "U.S. Savings Plan"), (2) a supplemental defined contribution plan covering certain eligible employees working in the U.S. (the "U.S. Supplemental Savings Plan") and (3) a defined contribution savings plan covering certain employees working outside the U.S. (the "Non U.S. Savings Plan"). In the years ended December 31, 2015, 2014 and 2013, we recognized expense of $89 million, $84 million and $88 million, respectively, related to our defined contribution plans.

For the U.S. Savings Plan, effective January 1, 2015, we amended the plan to increase our matching contribution to be up to 10.0 percent of each participant's base salary based on the participant's contribution to the plan. In the years ended December 31, 2014 and 2013, we made matching contributions of up to 6.0 percent of each participant's base salary based on the participant's contribution to the plan. The U.S. Supplemental Savings Plan, effective January 1, 2015, provides eligible employees with benefits in excess of those allowed under the U.S. Savings Plan.

For the Non U.S. Savings Plan, in addition to a matching contribution of up to 6.0 percent of each participant's base salary based on the participant's contribution to the plans, we contribute between 4.5 percent and 6.5 percent of each participant's base salary, based on the participant's years of eligible service.

Note 14—Commitments and Contingencies

Lease obligations

We have operating lease obligations expiring at various dates, principally for real estate, office space and office equipment. In the years ended December 31, 2015, 2014 and 2013, our rental expense for all operating leases, including operating leases with terms of less than one year, was approximately $72 million, $95 million and $128 million, respectively.

We also have a capital lease obligation, which is due to expire in August 2029. In the years ended December 31, 2015, 2014 and 2013, depreciation expense associated with Petrobras 10000, the asset held under capital lease, was $23 million, $21 million and $20 million, respectively.

At December 31, 2015 and 2014, the aggregate carrying amount of this asset held under capital lease was as follows (in millions):

	December 31, 2015	2014
Property and equipment, cost	$ 774	$ 780
Accumulated depreciation	(125)	(105)
Property and equipment, net	$ 649	$ 675

At December 31, 2015, the aggregate future minimum rental payments related to our non-cancellable operating leases and the capital lease were as follows (in millions):

	Capital lease	Operating leases
Years ending December 31,		
2016	$ 71	$ 15
2017	71	15
2018	72	10
2019	72	10
2020	72	9
Thereafter	616	62
Total future minimum rental payment	974	$ 121
Less amount representing imputed interest	(383)	
Present value of future minimum rental payments under capital leases	591	
Less current portion included in debt due within one year	(23)	
Long-term capital lease obligation	$ 568	

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TRANSOCEAN LTD. AND SUBSIDIARIES

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Purchase obligations

At December 31, 2015, the aggregate future payments required under our purchase obligations, primarily related to our newbuild construction programs, were as follows (in millions):

	Purchase obligations
Years ending December 31,	
2016	$ 968
2017	213
2018	395
2019	779
Thereafter	609
Total	$ 2,964

Macondo well incident commitments and contingencies

Overview—On April 22, 2010, the ultra deepwater floater Deepwater Horizon sank after a blowout of the Macondo well caused a fire and explosion on the rig off the coast of Louisiana. At the time of the explosion, Deepwater Horizon was contracted to an affiliate of BP plc. (together with its affiliates, "BP"). Following the incident, we have been subject to civil and criminal claims, as well as causes of action, fines and penalties by local, state and federal governments. Litigation commenced shortly after the incident, and most claims against us were consolidated by the U.S. Judicial Panel on Multidistrict Litigation and transferred to the U.S. District Court for the Eastern District of Louisiana (the "MDL Court"). A significant portion of the contingencies arising from the Macondo well incident has now been resolved as a result of settlements with the U.S. Department of Justice (the "DOJ"), BP, the states of Alabama, Florida, Louisiana, Mississippi, and Texas (collectively, the "States") and the Plaintiffs' Steering Committee (the "PSC").

During the year ended December 31, 2015, in connection with the settlements, as further described below, we adjusted our assets and liabilities associated with contingencies resulting from the Macondo well incident. In the year ended December 31, 2015, we recognized income of $788 million ($735 million, or $2.02 per diluted share, net of tax) recorded as a net reduction to operating and maintenance costs and expenses, including $538 million associated with recoveries from insurance for our previously incurred losses, $125 million associated with partial reimbursement from BP for our previously incurred legal costs, and $125 million associated with a net reduction to certain related contingent liabilities, primarily associated with contingencies that have either been settled or otherwise resolved as a result of settlements with BP and the PSC. We made such adjustments with corresponding entries to increase accounts receivable by $663 million and decrease other current liabilities by $125 million. In the year ended December 31, 2015, we received cash proceeds of $663 million, including $125 million from BP and $538 million from insurance, associated with reimbursement for or recoveries of previously incurred losses.

We have recognized a liability for the remaining estimated loss contingencies associated with litigation resulting from the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. At December 31, 2015 and 2014, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $250 million and $426 million, respectively, recorded in other current liabilities. We believe the remaining most notable claims against us arising from the Macondo well incident are the potential settlement class opt outs from the PSC Settlement Agreement, as described below. The liability for estimated loss contingencies at December 31, 2015, included, among others, the amount we have agreed to pay as a result of our settlement with the PSC (see "—PSC Settlement Agreement" below), which is subject to approval by the MDL Court. The remaining litigation could result in certain loss contingencies that we believe are reasonably possible. Although we have not recognized a liability for such loss contingencies, these contingencies could result in liabilities that we ultimately recognize.

We recognize an asset associated with the portion of our estimated losses that we believe is probable of recovery from insurance and for which we had received from underwriters' confirmation of expected payment. At December 31, 2014, the insurance recoverable asset was $10 million, recorded in other assets. Although we have available policy limits that could result in additional amounts recoverable from insurance, recovery of such additional amounts is not probable and we are not currently able to estimate such amounts (see "—Insurance coverage"). Our estimates involve a significant amount of judgment.

We believe we have agreements that will resolve substantially all outstanding claims against us arising from the Macondo well incident through a series of settlements with the following parties:

§ U.S. Department of Justice—Guilty plea agreement ("Plea Agreement") and civil consent decree ("Consent Decree"), entered into on January 3, 2013, provide for $1.4 billion in fines and penalties, payable in installments through February 2017, and require us to take a number of certain actions, including to enhance safety and environmental compliance when operating in U.S. waters, as further specified below.
§ U.S. Environmental Protection Agency—Administrative agreement (the "EPA Agreement"), entered into on February 25, 2013, resolves all matters related to suspension, debarment and disqualification and requires us to comply with the Plea Agreement and Consent Decree and continue implementation of certain programs and undertake further actions as specified below. Pursuant to the EPA Agreement, we must refrain from engaging in business relationships with persons or entities that are restricted from conducting business in the U.S.
§ BP—Settlement Agreement ("BP Settlement Agreement"), entered into on May 20, 2015, resolves all Macondo litigation and claims between BP and us, commits BP to pay us $125 million, to indemnify us for compensatory damages from oil pollution, and provides for the mutual release of all claims, including claims by BP to be an unlimited additional insured under our insurance policies.
§ Plaintiff Steering Committee—Settlement agreement (the "PSC Settlement Agreement") filed with the MDL Court on May 29, 2015 and subject to approval by the MDL Court, obligates us to pay $212 million to private plaintiffs, businesses and local governments, and up to an additional $25 million for reimbursement of plaintiff attorneys' fees in exchange for a release of claims brought by the PSC against us.
§ The States—Settlement Agreement (the "States Settlement Agreement"), effective October 13, 2015, obligates us to make a cash payment of $35 million to the States in exchange for release of all claims arising from the Macondo well incident.

Payments made pursuant to the Plea Agreement and Consent Decree are not deductible for tax purposes and may not be used as a basis for indemnity or reimbursement from BP or other defendants involved in the Macondo well incident litigation. Further detail regarding our settlement obligations and the restrictions that apply to us is provided below.

Plea Agreement—Pursuant to the Plea Agreement, one of our subsidiaries pled guilty to one misdemeanor count of negligently discharging oil into the U.S. Gulf of Mexico, in violation of the Clean Water Act ("CWA") and agreed to be subject to probation through February 2018. The DOJ agreed, subject to the provisions of the Plea Agreement, not to further prosecute us for certain matters arising from the Macondo well incident. We remain subject to probation through February 2018.

We also agreed to make an aggregate cash payment of $400 million, including a criminal fine of $100 million and cash contributions of $150 million to the National Fish & Wildlife Foundation and $150 million to the National Academy of Sciences, payable in scheduled installments. In the years ended December 31, 2015, 2014 and 2013, we made an aggregate cash payment of $60 million, $60 million and $160 million, respectively, in satisfaction of amounts due under the Plea Agreement. At December 31, 2015 and 2014, the carrying amount of our liability for settlement obligations under the Plea Agreement was $120 million and $180 million, respectively. At December 31, 2015, the aggregate future payments required under our outstanding settlement obligations under the Plea Agreement were $60 million in each of the years ending December 31, 2016 and 2017.

Consent Decree—Pursuant to the Consent Decree, we agreed to pay $1.0 billion in civil penalties, excluding interest. In the years ended December 31, 2015, 2014 and 2013, we paid $204 million, $412 million and $404 million, respectively, including interest at a rate of 2.15 percent, in satisfaction of amounts due under the Consent Decree. As of December 31, 2015, we have satisfied our required payments due under the Consent Decree. At December 31, 2014, the amount due under the Consent Decree was $200 million, recorded in other current liabilities.

Under the Consent Decree, we also agreed to undertake certain actions, including enhanced safety and compliance actions when operating in U.S. waters. The Consent Decree also requires us to submit certain plans, reports and submissions and also requires us to make such submittals available publicly. One of the required plans is a performance plan (the "Performance Plan") that contains, among other things, interim milestones for actions in specified areas and schedules for reports required under the Consent Decree. On January 2, 2014, the DOJ approved our proposed Performance Plan. Additionally, in compliance with the requirements of the Consent Decree and upon approval by the DOJ, we have retained an independent auditor to review and report to the DOJ our compliance with the Consent Decree and an independent process safety consultant to review report and assist with the process safety requirements of the Consent Decree.

Under the terms of the Consent Decree, the U.S. agreed not to sue Transocean Ltd. and certain of its subsidiaries for civil or administrative penalties for the Macondo well incident under specified provisions of the CWA, the Outer Continental Shelf Lands Act ("OCSLA"), the Endangered Species Act, the Marine Mammal Protection Act, the National Marine Sanctuaries Act, the federal Oil and Gas Royalty Management Act, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Emergency Planning and Community Right to Know Act ("EPCRA") and the Clean Air Act. In addition, the Consent Decree resolved our appeal of the incidents of noncompliance under the OCSLA issued by the Bureau of Safety and Environmental Enforcement without any admission of liability by us.

We may request termination of the Consent Decree after January 2, 2019, provided we meet certain conditions set forth in the Consent Decree. The Consent Decree resolved the claim by the U.S. for civil penalties under the Clean Water Act. The Consent Decree did not resolve United States' claim under the Oil Pollution Act ("OPA") for natural resource damages ("NRD") or for removal costs. However, BP has agreed to indemnify us for NRD and most removal costs as further discussed under "—BP Settlement Agreement" below.

EPA Agreement—On February 25, 2013, we and the EPA entered into 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.

BP Settlement Agreement—On May 20, 2015, we entered into a settlement agreement with BP (the "BP Settlement Agreement"). We believe the BP Settlement Agreement resolves all Macondo well-related litigation between BP and us, and the indemnity BP has committed to provide will generally address claims by third parties, including claims for economic and property damages, economic loss and NRD. However, the indemnity obligations do not extend to fines, penalties, or punitive damages. The BP Settlement Agreement requires that:

§ BP pay us $125 million, and we received such payment in July 2015, as partial reimbursement of the legal costs we have incurred in connection with the Macondo well incident;
§ BP indemnify us for compensatory damages, including all natural resource damages and all cleanup and removal costs for oil or pollutants originating from the Macondo well;
§ We indemnify BP for personal and bodily injury claims of our employees and for any future costs for the cleanup or removal of pollutants stored on the Deepwater Horizon vessel;
§ BP cease efforts to recover as an unlimited additional insured under our insurance policies, and be bound to the insurance reimbursement rulings related to the Macondo well incident;
§ BP and we each release and withdraw all claims we have against each other arising from the Macondo well litigation; and
§ Neither BP nor we make statements regarding gross negligence in the Macondo well incident.

BP settlement with the U.S. and the States—On July 2, 2015, BP announced it had reached an agreement in principle to settle claims with the U.S.; the States and local governments in the U.S. Gulf region. On October 5, 2015, BP, the U.S. and the States filed a proposed consent decree that is subject to approval by the MDL Court. If approved, the agreement will resolve the claims of the U.S. and the States for NRD under OPA. This agreement, together with the NRD indemnity obligations by BP pursuant to the BP Settlement Agreement, largely eliminates potential liability we may have arising from NRD claims. Accordingly, we believe that our likelihood of loss resulting from any NRD claims is remote.

PSC Settlement Agreement—On May 29, 2015, together with the PSC, we filed a settlement agreement (the "PSC Settlement Agreement") with the MDL Court for approval. Through the PSC Settlement Agreement, we agreed to pay a total of $212 million, plus up to $25 million for partial reimbursement of attorneys' fees, to be allocated between two classes of plaintiffs as follows: (1) private plaintiffs, businesses, and local governments who could have asserted punitive damages claims against us under general maritime law (the "Punitive Damages Class"); and (2) private plaintiffs who previously settled economic damages claims against BP and were assigned certain claims BP had made against us (the "Assigned Claims Class"). A court appointed neutral representative established the allocation of the settlement payment to be 72.8 percent paid to the Punitive Damages Class and 27.2 percent paid to the Assigned Claims Class. In exchange for these payments, each of the classes agreed to release all respective claims it has against us. Members of the Punitive Damages Class may opt out of the PSC Settlement Agreement and pursue punitive damages claims against us, but we may terminate the PSC Settlement Agreement if the number of opt outs exceeds a specified threshold amount. In August 2015, we made a cash deposit of $212 million into an escrow account pending approval of the settlement by the MDL Court. At December 31, 2015, the balance of the escrow account was $212 million, recorded in other current assets.

States settlement agreement—Effective October 13, 2015, we finalized a settlement agreement with 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.

Multidistrict litigation proceeding—Most Macondo well-related claims against us have been resolved under various settlements, described above. There are, however, still pending claims by potential opt outs from the settlement with the PSC and a number of other parties. As of December 31, 2015, the MDL Court has completed the liability phase trial, and additional litigation and appeals continue.

The Phase One trial in 2013 addressed fault for the Macondo blowout and resulting oil spill. The MDL Court's September 2014 Phase One ruling concluded that BP was grossly negligent and reckless and 67 percent at fault for the blowout, explosion, and spill; that we

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were negligent and 30 percent at fault; and that Halliburton Company ("Halliburton") was negligent and three percent at fault. The finding that we were negligent, but not grossly negligent, meant that, subject to a successful appeal, we would not be held liable for punitive damages and that BP was required to honor its contractual agreements to indemnify us for compensatory damages and release its claims against us. Our settlements with BP and the PSC finally resolve the indemnity and release issues (see "—BP Settlement Agreement" and "—PSC Settlement Agreement") and, upon court approval of such settlements, largely eliminate our risk should these determinations be reversed through the appeal process. The MDL Court also concluded that we were an "operator" of the Macondo well for purposes of 33 U.S.C. § 2704(c)(3), a provision of OPA that permits government entities to recover removal costs by owners and operators of a facility or vessel that caused a discharge. The MDL Court, however, found that "Transocean's liability to government entities for removal costs is ultimately shifted to BP by virtue of contractual indemnity," and BP has agreed to indemnify removal costs through the BP Settlement Agreement (see "—BP Settlement Agreement").

The Phase One ruling did not quantify damages or result in a final monetary judgment. However, because it is a determination of liability under maritime law, the Phase One ruling is appealable, and we, along with BP, the PSC, Halliburton and the State of Alabama have each appealed or cross-appealed aspects of the ruling. These appeals have been stayed pending the finalization and court approval of BP's settlement with the U.S. and the States. As a result of our settlements, we do not expect any party to challenge the ruling with respect to Transocean when the appeals resume, and we expect that any remaining issues in the appeal would be addressed to the other parties.

We can provide no assurances as to the outcome of these appeals, as to the timing of any further rulings, or that we will not enter into additional settlements as to some or all of the matters related to the Macondo well incident, including those to be determined at a trial, or the timing or terms of any such settlements.

Pending claims—As of December 31, 2015, approximately 1,376 actions or claims are pending against us, along with other unaffiliated defendants arising from individual complaints as well as putative class-action complaints that were filed in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Florida and other courts. These claims were originally filed in various state and federal courts, and most have been consolidated in the MDL Court. We believe our settlement with the PSC, if approved by the MDL Court, will resolve many of these pending actions. As for any actions not resolved by these settlements, including any claims by individuals who opt out of the PSC Settlement Agreement, claims by private environmental groups, and securities actions, we are vigorously defending those claims and pursuing any and all defenses available.

State and other government claims—Claims have been filed against us by over 200 state, local and foreign governments, including the Mexican States of Veracruz, Quintana Roo, Tamaulipas and Yucatan; the federal government of Mexico and other local governments by and on behalf of multiple towns and parishes.

The OPA claims of the Mexican States of Veracruz, Quintana Roo, Tamaulipas and Yucatan were dismissed for failure to demonstrate that recovery under OPA was authorized by treaty or executive agreement. The MDL Court subsequently granted summary judgment and the Fifth Circuit upheld the decision on the Mexican States' general maritime law claims on the ground that the federal government of Mexico, rather than the Mexican States, had the proprietary interest in the claims, and the U.S. Supreme Court denied review.

Federal securities claims—On September 30, 2010, a proposed federal securities class action was filed against us in the U.S. District Court for the Southern District of New York. In the action, a former shareholder of the acquired company alleged that the joint proxy statement related to our shareholder meeting in connection with the merger with the acquired company violated various securities laws and that the acquired company's shareholders received inadequate consideration for their shares as a result of the alleged violations and sought compensatory and rescissory damages and attorneys' fees. On March 11, 2014, the District Court for the Southern District of New York dismissed the claims as time-barred. Plaintiffs appealed to the U.S. Court of Appeals for the Second Circuit, which heard oral argument on August 18, 2015. The court has not yet issued a ruling.

Wreck removal—In December 2010, the U.S. Coast Guard requested that we formulate and submit a comprehensive oil removal plan to remove any diesel fuel that could be recovered from the Deepwater Horizon vessel. The U.S. Coast Guard has not requested that we remove the rig wreckage from the sea floor. However, in February 2013, the U.S. Coast Guard submitted a request seeking analysis of the rig's riser and cofferdam, which are resting on the seafloor, and recommendations for remediation or removal. Although we have insurance coverage for wreck removal, such coverage may be less than the total costs required to remove the wreckage from the sea floor. Under the BP Settlement Agreement, we have agreed to indemnify BP for any costs associated with wreck removal, if requested.

Insurance coverage—At the time of the Macondo well incident, our excess liability insurance program offered aggregate insurance coverage of $950 million, excluding a $15 million deductible and a $50 million self-insured layer through our wholly owned captive insurance subsidiary. This excess liability insurance coverage consisted of a first and a second layer of $150 million each, a third and fourth layer of $200 million each and a fifth layer of $250 million. We have recovered costs under the first four excess layers, the limits of which are now fully exhausted. We have submitted claims to the $250 million fifth layer, which if paid, will exhaust such coverage. This layer is comprised of Bermuda market insurers (the "Bermuda Insurers"). The Bermuda Insurers have asserted various coverage defenses to our claims, and we have issued arbitration notices to the Bermuda Insurers.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Other legal proceedings

Asbestos litigation—In 2004, several of our subsidiaries were named, along with numerous other unaffiliated defendants, in 21 complaints filed on behalf of 769 plaintiffs in the Circuit Courts of the State of Mississippi and which claimed injuries arising out of exposure to asbestos allegedly contained in drilling mud during these plaintiffs' employment in drilling activities between 1965 and 1986. The complaints generally allege that the defendants used or manufactured asbestos containing drilling mud additives for use in connection with drilling operations and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling related products that contained asbestos. The plaintiffs generally seek awards of unspecified compensatory and punitive damages, but the court appointed special master has ruled that a Jones Act employer defendant, such as us, cannot be sued for punitive damages. After ten years of litigation, this group of cases has been winnowed to the point where now only 15 plaintiffs' individual claims remain pending in Mississippi in which we have or may have an interest. During the year ended December 31, 2014, a group of lawsuits premised on the same allegations as those in Mississippi were filed in Louisiana. As of December 31, 2015, eight plaintiffs have claims pending against one or more of our subsidiaries in four different lawsuits filed in Louisiana. We intend to defend these lawsuits vigorously, although we can provide no assurance as to the outcome. We historically have maintained broad liability insurance, although we are not certain whether insurance will cover the liabilities, if any, arising out of these claims. Based on our evaluation of the exposure to date, we do not expect the liability, if any, resulting from these claims to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

One of our subsidiaries was involved in lawsuits arising out of the subsidiary's involvement in the design, construction and refurbishment of major industrial complexes. The operating assets of the subsidiary were sold and its operations were discontinued in 1989, and the subsidiary has no remaining assets other than the insurance policies involved in its litigation, with its insurers and, either directly or indirectly through a qualified settlement fund. The subsidiary has been named as a defendant, along with numerous other companies, in lawsuits alleging bodily injury or personal injury as a result of exposure to asbestos. As of December 31, 2015, the subsidiary was a defendant in approximately 291 lawsuits, some of which include multiple plaintiffs, and we estimate that there are approximately 324 plaintiffs in these lawsuits. For many of these lawsuits, we have not been provided with sufficient information from the plaintiffs to determine whether all or some of the plaintiffs have claims against the subsidiary, the basis of any such claims, or the nature of their alleged injuries. The first of the asbestos related lawsuits was filed against the subsidiary in 1990. Through December 31, 2015, the costs incurred to resolve claims, including both defense fees and expenses and settlement costs, have not been material, all known deductibles have been satisfied or are inapplicable, and the subsidiary's defense fees and expenses and settlement costs have been met by insurance made available to the subsidiary. The subsidiary continues to be named as a defendant in additional lawsuits, and we cannot predict the number of additional cases in which it may be named a defendant nor can we predict the potential costs to resolve such additional cases or to resolve the pending cases. However, the subsidiary has in excess of $1.0 billion in insurance limits potentially available to the subsidiary. Although not all of the policies may be fully available due to the insolvency of certain insurers, we believe that the subsidiary will have sufficient funding directly or indirectly from settlements and claims payments from insurers, assigned rights from insurers and coverage in place settlement agreements with insurers to respond to these claims. While we cannot predict or provide assurance as to the outcome of these matters, we do not believe that the ultimate liability, if any, arising from these claims will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Rio de Janeiro tax assessment—In the third quarter of 2006, we received tax assessments of BRL 450 million, equivalent to approximately $114 million, including interest and penalties, from the state tax authorities of Rio de Janeiro in Brazil against one of our Brazilian subsidiaries for taxes on equipment imported into the state in connection with our operations. The assessments resulted from a preliminary finding by these authorities that our record keeping practices were deficient. We currently believe that the substantial majority of these assessments are without merit. We filed an initial response with the Rio de Janeiro tax authorities on September 9, 2006 refuting these additional tax assessments. In September 2007, we received confirmation from the state tax authorities that they believe the additional tax assessments are valid, and as a result, we filed an appeal on September 27, 2007 to the state Taxpayer's Council contesting these assessments. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Brazilian import license assessment—In the fourth quarter of 2010, we received an assessment from the Brazilian federal tax authorities in Rio de Janeiro of BRL 575 million, equivalent to approximately $145 million, including interest and penalties, based upon the alleged failure to timely apply for import licenses for certain equipment and for allegedly providing improper information on import license applications. We believe that a substantial majority of the assessment is without merit and are vigorously pursuing legal remedies. The case was decided partially in favor of our Brazilian subsidiary in the lower administrative court level. The decision cancelled the majority of the assessment, reducing the total assessment to BRL 38 million, equivalent to approximately $10 million. On July 14, 2011, we filed an appeal to eliminate the assessment. On May 23, 2013, a ruling was issued that eliminated all assessment amounts. A further appeal by the taxing authorities was filed in November 2014 and accepted for review in April 2015. While we cannot predict or provide assurance as to the outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Nigerian Cabotage Act litigation—In October 2007, three of our subsidiaries were each served a Notice and Demand from the Nigeria Maritime Administration and Safety Agency, imposing a two percent surcharge on the value of all contracts performed by us in Nigeria pursuant to the Coastal and Inland Shipping (Cabotage) Act 2003 (the "Cabotage Act"). Our subsidiaries each filed an originating summons in the Federal High Court in Lagos challenging the imposition of this surcharge on the basis that the Cabotage Act and associated levy is not applicable to drilling rigs. The respondents challenged the competence of the suits on several procedural grounds. The court upheld the objections and dismissed the suits. In December 2010, our subsidiaries filed a new joint Cabotage Act suit. While we cannot predict or provide assurance as to the outcome of these proceedings, we do not expect the proceedings to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other matters—We are involved in various tax matters, various regulatory matters, and a number of claims and lawsuits, asserted and unasserted, all of which have arisen in the ordinary course of our business. We do not expect the liability, if any, resulting from these other matters to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such other pending, threatened, or possible litigation or liability. We can provide no assurance that our beliefs or expectations as to the outcome or effect of any tax, regulatory, lawsuit or other litigation matter will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

Other environmental matters

Hazardous waste disposal sites—We have certain potential liabilities under the Comprehensive Environment Response, Compensation and Liability Act ("CERCLA") and similar state acts regulating cleanup of various hazardous waste disposal sites, including those described below. CERCLA is intended to expedite the remediation of hazardous substances without regard to fault. Potentially responsible parties ("PRPs") for each site include present and former owners and operators of, transporters to and generators of the substances at the site. Liability is strict and can be joint and several.

We have been named as a PRP in connection with a site located in Santa Fe Springs, California, known as the Waste Disposal, Inc. site. We and other PRPs have agreed with the Environmental Protection Agency (the "EPA") and the DOJ to settle our potential liabilities for this site by agreeing to perform the remaining remediation required by the EPA. The form of the agreement is a consent decree, which has been entered by the court. The parties to the settlement have entered into a participation agreement, which makes us liable for approximately eight percent of the remediation and related costs. The remediation is complete, and we believe our share of the future operation and maintenance costs of the site is not material. There are additional potential liabilities related to the site, but these cannot be quantified, and we have no reason at this time to believe that they will be material.

One of our subsidiaries has been ordered by the California Regional Water Quality Control Board ("CRWQCB") to develop a testing plan for a site known as Campus 1000 Fremont in Alhambra, California. This site was formerly owned and operated by certain of our subsidiaries. It is presently owned by an unrelated party, which received an order to test the property. We have also been advised that one or more of our subsidiaries is likely to be named by the EPA as a PRP for the San Gabriel Valley, Area 3, Superfund site, which includes this property. Testing has been completed at the property, but no contaminants of concern were detected. In discussions with CRWQCB staff, we were advised of their intent to issue us a "no further action" letter, but it has not yet been received. Based on the test results, we would contest any potential liability. We have no knowledge at this time of the potential cost of any remediation, who else will be named as PRPs, and whether in fact any of our subsidiaries is a responsible party. The subsidiaries in question do not own any operating assets and have limited ability to respond to any liabilities.

Resolutions of other claims by the EPA, the involved state agency or PRPs are at various stages of investigation. These investigations involve determinations of (a) the actual responsibility attributed to us and the other PRPs at the site, (b) appropriate investigatory or remedial actions and (c) allocation of the costs of such activities among the PRPs and other site users. Our ultimate financial responsibility in connection with those sites may depend on many factors, including (i) the volume and nature of material, if any, contributed to the site for which we are responsible, (ii) the number of other PRPs and their financial viability and (iii) the remediation methods and technology to be used.

It is difficult to quantify with certainty the potential cost of these environmental matters, particularly in respect of remediation obligations. Nevertheless, based upon the information currently available, we believe that our ultimate liability arising from all environmental matters, including the liability for all other related pending legal proceedings, asserted legal claims and known potential legal claims which are likely to be asserted, is adequately accrued and should not have a material effect on our consolidated statement of financial position or results of operations.

Retained risk

Overview—Our hull and machinery and excess liability insurance program is comprised of commercial market and captive insurance policies that we renew annually on May 1. We periodically evaluate our insurance limits and self insured retentions. At December 31, 2015, the insured value of our drilling rig fleet was approximately $20.4 billion, excluding our rigs under construction. Additionally, we maintain various other commercial lines of insurance covering the business. We generally do not carry commercial market insurance coverage for loss of revenues or for losses resulting from physical damage to our fleet caused by named windstorms in the U.S. Gulf of Mexico, including liability for wreck removal costs.

TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Hull and machinery coverage—At December 31, 2015, under the hull and machinery program, we generally maintained a $125 million per occurrence deductible, limited to a maximum of $200 million per policy period. Subject to the same shared deductible, we also had coverage for an amount equal to 50 percent of a rig's insured value for combined costs incurred to mitigate rig damage, wreck or debris removal and collision liability. Any excess wreck or debris removal costs and excess collision liability costs are generally covered to the extent of our remaining excess liability coverage.

Excess liability coverage—At December 31, 2015, we carried excess liability coverage of $700 million in the commercial market excluding the deductibles and self insured retention noted below, which generally covers offshore risks such as personal injury, third party property claims, and third party non crew claims, including wreck removal and pollution. Our excess liability coverage had separate $10 million per occurrence deductibles on collision liability claims and $5 million per occurrence deductibles on crew personal injury claims and on other third party non crew claims. Through our wholly owned captive insurance company, we retained the risk of the primary $50 million excess liability coverage. In addition, we generally retained the risk for any liability losses in excess of $750 million.

Letters of credit and surety bonds

At December 31, 2015 and 2014, we had outstanding letters of credit totaling $153 million and $338 million, respectively, issued under various committed and uncommitted credit lines provided by several banks to guarantee various contract bidding, performance activities and customs obligations. At December 31, 2014, such outstanding letters of credit included an amount of $91 million that we agreed to maintain in support of the operations for Shelf Drilling. Our commitment to provide such financial support expired in November 2015 (see Note 7—Discontinued Operations).

As is customary in the contract drilling business, we also have various surety bonds in place that secure customs obligations related to the importation of our rigs and certain performance and other obligations. At December 31, 2015 and 2014, we had outstanding surety bonds totaling $30 million and $6 million, respectively.

Note 15—Noncontrolling Interest

Redeemable noncontrolling interest—Changes in redeemable noncontrolling interest were as follows (in millions):

	Years ended December 31,		
	2015	2014	2013
Redeemable noncontrolling interest			
Balance, beginning of period	$ 11	$ —	$ —
Net income (loss) attributable to noncontrolling interest	(3)	9	—
Reclassification from noncontrolling interest	—	2	—
Balance, end of period	$ 8	$ 11	$ —

Angola Deepwater Drilling Company Limited—We own a 65 percent interest and Angco Cayman Limited ("Angco Cayman") owns a 35 percent interest, in ADDCL, a variable interest entity (see Note 4—Variable Interest

Entities). Angco Cayman has the right to require us to purchase its shares for cash. Accordingly, we present the carrying amount of Angco Cayman's ownership interest as redeemable noncontrolling interest on our consolidated balance sheets.

Noncontrolling interest—On February 6, 2014, we formed Transocean Partners to own, operate and acquire modern, technologically advanced offshore drilling rigs. Transocean Partners holds a 51 percent ownership interest in the entities that own and operate the ultra deepwater floaters Development Driller III, Discoverer Clear Leader and Discoverer Inspiration, all of which are currently located in the U.S. Gulf of Mexico. On August 5, 2014, we completed the initial public offering of 20.1 million common units of Transocean Partners. We hold the remaining 21.3 million common units, 27.6 million subordinated units, which collectively represented a 70.8 percent limited liability company interest, and all of the incentive distribution rights. In the year ended December 31, 2014, as a result of the offering, we received cash proceeds of $417 million, net of $26 million for underwriting discounts and commissions and other offering costs, and we recorded a capital allocation resulting in a decrease of $44 million to noncontrolling interest and a corresponding increase to additional paid in capital.

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. Subject to market conditions, Transocean Partners may repurchase units from time to time in the open market or in privately negotiated transactions. It may suspend or discontinue the program at any time. The common units repurchased under the program will be cancelled. In the year ended December 31, 2015, Transocean Partners repurchased 91,500 of its publicly held common units for an aggregate purchase price of $1 million. As of December 31, 2015, we held a 70.9 percent limited liability company interest in Transocean Partners.

In the years ended December 31, 2015 and 2014, Transocean Partners declared and paid an aggregate distribution of $100 million and $15 million, respectively, to its unitholders, of which $29 million and $4 million, respectively, was paid to the holders of noncontrolling interest and $71 million and $11 million, respectively, was paid to us and was eliminated in consolidation.

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

During the years ended December 31, 2015 and 2014, as a result of transactions with holders of noncontrolling interest in other subsidiaries, we recorded an allocation of capital, which resulted in a decrease of $9 million and an increase of $11 million, respectively, to noncontrolling interest with corresponding adjustments to additional paid in capital.

See Note 5—Impairments.

Note 16—Shareholders' Equity

Par value reduction—On October 29, 2015, shareholders at our extraordinary general meeting 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. See Note 25—Subsequent Events.

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. We do not pay the distribution of qualifying additional paid in capital with respect to our shares held in treasury or held by our subsidiary. 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 May 29 and August 25, 2015. On October 29, 2015, shareholders at the extraordinary general meeting approved the cancellation of the third and fourth installments of the distribution. As a result, we reduced our distribution payable, recorded in other current liabilities, by $109 million with corresponding increase to additional paid in capital.

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. We do not pay the distribution of qualifying additional paid in capital with respect to our shares held in treasury or held by our subsidiary. In May 2014, we recognized a liability of $1.1 billion for the distribution payable, recorded in other current liabilities, with a corresponding entry to additional paid in capital. 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. At December 31, 2014, the aggregate carrying amount of the distribution payable was $272 million. 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 of $0.56 per outstanding share, subject to certain limitations. We do not pay the distribution of qualifying additional paid in capital with respect to our shares held in treasury or held by our subsidiary. In May 2013, we recognized a liability of $808 million for the distribution payable, recorded in other current liabilities, with a corresponding entry to additional paid in capital. On June 19, September 18 and December 18, 2013, we paid the first three installments in the aggregate amount of $606 million to shareholders of record as of May 31, August 23 and November 15, 2013, respectively. 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.

Shares held in treasury—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 $3.5 billion. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program.

During the years ended December 31, 2015, 2014 and 2013, we did not purchase any of our shares under our share repurchase program. At December 31, 2015 and 2014, we held 2.9 million shares in treasury, recorded at cost. On October 29, 2015, shareholders at our extraordinary general meeting approved the cancellation of all shares that have been repurchased to date under our share repurchase program. See Note 25—Subsequent Events.

Shares held by subsidiary—One of our subsidiaries holds our shares for future use to satisfy our obligations to deliver shares in connection with awards granted under our incentive plans or other rights to acquire our shares. At December 31, 2015 and 2014, our subsidiary held 6.9 million shares and 8.7 million shares, respectively.

Accumulated other comprehensive loss—The changes in accumulated other comprehensive loss, presented net of tax, were as follows (in millions):

	Year ended December 31, 2015			Year ended December 31, 2014		
	Defined benefit pension plans	Derivative instruments	Total	Defined benefit pension plans	Derivative instruments	Total
Balance, beginning of period	$ (404)	$ —	$ (404)	$ (264)	$ 2	$ (262)
Other comprehensive income (loss) before reclassifications	48	—	48	(155)	—	(155)
Reclassifications to net income	22	—	22	15	(2)	13
Other comprehensive income (loss), net	70	—	70	(140)	(2)	(142)
Balance, end of period	$ (334)	$ —	$ (334)	$ (404)	$ —	$ (404)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

Note 17—Share Based Compensation Plans

Overview

We have (i) a long term incentive plan (the "Long Term Incentive Plan") for executives, key employees and non employee directors under which awards can be granted in the form of restricted share units, restricted shares, stock options, stock appreciation rights and cash performance awards and (ii) other incentive plans under which awards are currently outstanding. Awards may be granted as service awards that are earned over a defined service period or as performance awards that are earned based on the achievement of certain market factors or performance targets or a combination of market factors and performance targets. Our compensation committee of our board of directors determines the terms and conditions of the awards granted under the Long Term Incentive Plan. As of December 31, 2015, we had 55.4 million shares authorized and 21.2 million shares available to be granted under the Long Term Incentive Plan.

Service awards typically vest either in three equal annual installments beginning on the first anniversary date of the grant or in an aggregate installment at the end of the stated vesting period. Performance awards are typically awarded subject to a three year measurement period during which the number of options, shares or restricted share units remains uncertain. At the end of the measurement period, the awarded number of options, shares or restricted share units is determined subject to the stated vesting period. The performance awards generally vest in one aggregate installment following the determination date. Stock options and stock appreciation rights, once vested, generally have a seven year term during which they are exercisable.

As of December 31, 2015, total unrecognized compensation costs related to all unvested share based awards were $61 million, which are expected to be recognized over a weighted average period of 1.7 years. In the years ended December 31, 2015, 2014 and 2013, we recognized additional share based compensation expense of $9 million, $9 million and $22 million, respectively, in connection with modifications of share based awards.

Service awards

Restricted share units—A restricted share unit, also known as a deferred unit, is a notional unit that is equal to one share but has no voting rights until the underlying share is issued. Our service based restricted share units are participating securities since they have the right to receive dividends and other cash distributions to shareholders. The following table summarizes unvested activity for service based restricted share units granted under our incentive plans during the year ended December 31, 2015:

	Number of units	Weighted-average grant-date fair value per share
Unvested at January 1, 2015	2,270,853	$ 49.37
Granted	2,848,521	18.70
Vested	(1,817,758)	44.54
Forfeited	(271,172)	24.56
Unvested at December 31, 2015	3,030,444	$ 25.65

During the year ended December 31, 2015, the aggregate grant date fair value of the service based restricted share units that vested was $81 million.

During the years ended December 31, 2014 and 2013, we granted 1,208,790 and 1,691,029 service based restricted share units, respectively, with a weighted average grant date fair value of $42.80 and $58.91 per share, respectively. During the years ended December 31, 2014 and 2013, we had 1,520,023 and 1,556,840 service based restricted share units, respectively, that vested with an aggregate grant date fair value of $87 million and $95 million, respectively.

Stock options—In the years ended December 31, 2015 and 2014, we did not grant service awards in the form of stock options. In the year ended December 31, 2013, we estimated the grant date fair value of each stock option awarded under the Long Term Incentive Plan to be $17.37 per option. We estimated the fair value using the Black Scholes Merton option pricing model with the following weighted average assumptions: (a) a dividend yield of 2 percent, (b) an expected price volatility of 39 percent, (c) a risk free interest rate of 0.94 percent and (d) an expected option life of 5.3 years.

The following table summarizes activity for vested and unvested service based stock options outstanding under our incentive plans during the year ended December 31, 2015:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2015	1,746,243	$ 72.64	5.77	$ —
Forfeited	(90,821)	59.27	—	—
Expired	(33,105)	59.05	—	—
Outstanding at December 31, 2015	1,622,317	$ 73.66	4.81	$ —
Vested and exercisable at December 31, 2015	1,567,811	$ 74.16	4.73	$ —

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During the year ended December 31, 2015, no outstanding service based stock options were exercised. During the year ended December 31, 2015, the aggregate grant date fair value of service based stock options that vested was $9 million. As of December 31, 2015, there were outstanding unvested service based stock options to purchase 54,506 shares At January 1 and December 31, 2015, we have presented the aggregate intrinsic value as zero since the weighted average exercise price per share exceeded the market price of our shares on these dates.

During the year ended December 31, 2013, we granted service based stock options to purchase 455,915 shares with a weighted average grant date fair value of $17.37 per service based stock option. During the years ended December 31, 2014 and 2013, the total grant date fair value of service based stock options that vested was $14 million and $12 million, respectively. During the years ended December 31, 2014 and 2013, there were service based stock options to purchase 383,848 and 102,254 shares exercised, respectively. During the years ended December 31, 2014 and 2013, the total pre tax intrinsic value of service based stock options exercised was $2 million and $5 million, respectively.

Stock appreciation rights—The following table summarizes activity for service based stock appreciation rights outstanding under our incentive plans during the year ended December 31, 2015:

	Number of awards	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2015	187,739	$ 93.39	1.76	$ —
Forfeited	(2,737)	86.74	—	—
Outstanding at December 31, 2015	185,002	$ 93.49	0.76	$ —
Vested and exercisable at December 31, 2015	185,002	$ 93.49	0.76	$ —

During the years ended December 31, 2015, 2014 and 2013, we did not grant stock appreciation rights and no outstanding stock appreciation rights were exercised. As of December 31, 2015, there were no unvested stock appreciation rights outstanding. At January 1 and December 31, 2015, we have presented the aggregate intrinsic value as zero since the weighted average exercise price per share exceeded the market price of our shares on those dates.

Performance awards

Restricted share units—We grant performance awards in the form of restricted share units that can be earned depending on the achievement of (a) market factors or (b) both market factors and performance targets. Our performance awards are participating securities since they have the right to receive dividends and other cash distributions to shareholders. The number of restricted share units earned is quantified upon completion of the specified period at the determination date. The following table summarizes unvested activity for performance awards granted in the form of restricted share units under our incentive plans during the year ended December 31, 2015:

	Number of units	Weighted-average grant-date fair value per share	
Unvested at January 1, 2015	462,953	$	46.39
Granted	652,592		17.91
Vested	—		—
Vested and cancelled	(138,677)		74.05
Forfeited	(274,737)		25.38
Unvested at December 31, 2015	702,131	$	18.81

During the year ended December 31, 2015, no performance awards vested since neither the market factors nor the performance targets were achieved. The vested and cancelled performance awards presented above represent units that were unearned due to failure to achieve the required market condition or performance target.

During the years ended December 31, 2014 and 2013, there were 302,630 and 171,001 performance awards granted, respectively, with a weighted average grant date fair value of $31.73 and $74.05 per share, respectively. During the years ended December 31, 2014 and 2013, the total grant date fair value of the performance awards that vested was $8 million and $6 million, respectively.

Stock options—We have previously granted performance awards in the form of stock options that could be earned depending on the achievement of certain performance targets. The number of stock options earned was quantified upon completion of the performance

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period at the determination date. The following table summarizes activity for vested and unvested performance based stock options outstanding under our incentive plans during the year ended December 31, 2015:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2015	159,804	$ 81.17	1.41	$ —
Forfeited	(2,159)	59.99	—	—
Expired	(7,285)	59.99	—	—
Outstanding at December 31, 2015	150,360	$ 82.50	0.53	$ —
Vested and exercisable at December 31, 2015	150,360	$ 82.50	0.53	$ —

During the years ended December 31, 2015, 2014 and 2013, we did not grant performance awards in the form of stock options. At January 1 and December 31, 2015, we have presented the aggregate intrinsic value as zero since the weighted average exercise price per share exceeded the market price of our shares on that date. During the years ended December 31, 2014 and 2013, there were 12,073 and 7,385 performance-based stock options, respectively, exercised. As of December 31, 2015, there were no unvested performance based stock options outstanding.

Note 18—Supplemental Balance Sheet Information

Other current liabilities were comprised of the following (in millions):

	December 31, 2015	December 31, 2014
Other current liabilities		
Accrued payroll and employee benefits	$ 312	$ 387
Macondo well incident settlement obligations	60	260
Accrued interest	82	95
Accrued taxes, other than income	95	78
Distribution payable	—	272
Deferred revenue	187	219
Deferred revenue of consolidated variable interest entities	15	18
Contingent liabilities	271	460
Other	24	33
Total other current liabilities	$ 1,046	$ 1,822

Other long term liabilities were comprised of the following (in millions):

	December 31, 2015	December 31, 2014
Other long-term liabilities		
Accrued pension liabilities	$ 379	$ 459
Accrued retiree life insurance and medical benefits	20	56
Macondo well incident settlement obligations	60	120
Long-term income taxes payable	401	383
Deferred revenue	161	201
Deferred revenue of consolidated variable interest entities	17	32
Drilling contract intangibles	14	29
Other	56	74
Total other long-term liabilities	$ 1,108	$ 1,354

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Note 19—Supplemental Cash Flow Information

Net cash provided by operating activities attributable to the net change in operating assets and liabilities was composed of the following (in millions):

	Years ended December 31,		
	2015	2014	2013
Changes in operating assets and liabilities			
Decrease in accounts receivable	$ 757	$ 63	$ 58
Increase in other current assets	(177)	(164)	(152)
Decrease (increase) in other assets	5	(7)	87
Decrease in accounts payable and other current liabilities	(844)	(874)	(625)
Decrease in other long-term liabilities	(70)	(72)	(33)
Change in income taxes receivable / payable, net	(35)	(29)	(151)
	$ (364)	$ (1,083)	$ (816)

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

	Years ended December 31,		
	2015	2014	2013
Certain cash operating activities			
Cash payments for interest	$ 439	$ 490	$ 669
Cash payments for income taxes	314	329	457
Non-cash investing and financing activities			
Capital additions, accrued at end of period (a)	$ 128	$ 124	$ 167

(a) These amounts represent additions to property and equipment for which we had accrued a corresponding liability in accounts payable at the end of the period.

Note 20—Financial Instruments

The carrying amounts and fair values of our financial instruments were as follows:

	December 31, 2015		December 31, 2014	
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and cash equivalents	$ 2,339	$ 2,339	$ 2,635	$ 2,635
Notes and other loans receivable	—	—	15	15
Restricted cash balances and investments	467	474	377	394
Long-term debt, including current maturities	8,490	6,291	10,051	9,778
Derivative instruments, assets	2	2	11	11

We estimated the fair value of each class of financial instruments, for which estimating fair value is practicable, by applying the following methods and assumptions:

Cash and cash equivalents—The carrying amount of cash and cash equivalents represents the historical cost, plus accrued interest, which approximates fair value because of the short maturities of those instruments. We measured the estimated fair value of our cash equivalents using significant other observable inputs, representative of a Level 2 fair value measurement, including the net asset values of the investments. At December 31, 2015 and 2014, the aggregate carrying amount of our cash equivalents was $1.7 billion.

Loans receivable—We previously held certain loans receivable, which originated in connection with certain asset dispositions. The carrying amount represents the amortized cost of our investments. We measured the estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including the credit ratings of the borrowers. At December 31, 2014, the aggregate carrying amount of our loans receivable was $15 million, recorded in other assets.

Restricted cash investments—The carrying amount of the Eksportfinans Restricted Cash Investments represents the amortized cost of our investment. We measured the estimated fair value of the Eksportfinans Restricted Cash Investments using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads of the instruments. At December 31, 2015 and 2014, the aggregate carrying amount of the Eksportfinans Restricted Cash Investments was $216 million and $369 million, respectively. At December 31, 2015 and 2014, the estimated fair value of the Eksportfinans Restricted Cash Investments was $223 million and $386 million, respectively.

The carrying amount of the restricted cash balances that are subject to restrictions due to legislation, regulation or court order approximates fair value due to the short term nature of the instruments in which the restricted cash balances are held. At December 31, 2015 and 2014, the aggregate carrying amount of such restricted cash balances was $251 million and $8 million, respectively.

Debt—We measured the estimated fair value of our debt, all of which was fixed rate debt, using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads for the instruments.

Derivative instruments—The carrying amount of our derivative instruments represents the estimated fair value, excluding accrued interest. We measured the estimated fair value using significant other observable inputs, representative of a Level 2 fair value measurement, including the interest rates and terms of the instruments.

Note 21—Risk Concentration

Interest rate risk—Financial instruments that potentially subject us to concentrations of interest rate risk include our cash equivalents, short term investments, restricted cash investments, debt and capital lease obligations. We are exposed to interest rate risk related to our cash equivalents and short term investments, as the interest income earned on these investments changes with market interest rates. Floating rate debt, where the interest rate may be adjusted annually or more frequently over the life of the instrument, exposes us to short term changes in market interest rates. Fixed rate debt, where the interest rate is fixed over the life of the instrument and the instrument's maturity is greater than one year, exposes us to changes in market interest rates when we refinance maturing debt with new debt. Our fixed rate restricted cash investments associated with the Eksportfinans Loans and the respective debt instruments for which they are restricted, are subject to corresponding and opposing changes in the fair value relative to changes in market interest rates.

From time to time, we may use interest rate swap agreements to manage the effect of interest rate changes on future income. We do not generally enter into interest rate derivative transactions for speculative or trading purposes. Interest rate swaps are generally designated as hedges of underlying future interest payments. These agreements involve the exchange of amounts based on variable interest rates and amounts based on a fixed interest rate over the life of the agreement without an exchange of the notional amount upon which the payments are based. The interest rate differential to be received or paid on the swaps is recognized over the lives of the swaps as an adjustment to interest expense. Gains and losses on terminations of interest rate swap agreements are deferred and recognized as an adjustment to interest expense over the remaining life of the underlying debt. In the event of the early retirement of a designated debt obligation, any realized or unrealized gain or loss from the swap would be recognized in income.

Currency exchange rate risk—Our international operations expose us to currency exchange rate risk. This risk is primarily associated with compensation costs of our employees and purchasing costs from non U.S. suppliers, which are denominated in currencies other than the U.S. dollar. We use a variety of techniques to minimize the exposure to currency exchange rate risk, including the structuring of customer contract payment terms and, from time to time, the use of currency exchange derivative instruments.

Our primary currency exchange rate risk management strategy involves structuring customer contracts to provide for payment in both U.S. dollars and local currency. The payment portion denominated in local currency is based on anticipated local currency requirements over the contract term. Due to various factors, including customer acceptance, local banking laws, national content requirements, other statutory requirements, local currency convertibility and the impact of inflation on local costs, actual local currency needs may vary from those anticipated in the customer contracts, resulting in partial exposure to currency exchange rate risk. The currency exchange effect resulting from our international operations generally has not had a material impact on our operating results. In situations where payments of local currency do not equal local currency requirements, we may use currency exchange derivative instruments, specifically forward exchange contracts, or spot purchases, to mitigate currency exchange rate risk. A forward exchange contract obligates us to exchange predetermined amounts of specified foreign currencies at specified currency exchange rates on specified dates or to make an equivalent U.S. dollar payment equal to the value of such exchange.

Credit risk—Financial instruments that potentially subject us to concentrations of credit risk are primarily cash and cash equivalents, short term investments, trade receivables, notes and loans receivable and equity investment.

We generally maintain our cash and cash equivalents in time deposits at commercial banks with high credit ratings or mutual funds, which invest exclusively in high quality money market instruments. We limit the amount of exposure to any one institution and do not believe we are exposed to any significant credit risk.

We earn our revenues by providing our drilling services to international oil companies, government owned oil companies and government controlled oil companies. Receivables are dispersed in various countries (see Note 22—Operating Segments, Geographic Analysis and Major Customers). We establish an allowance for doubtful accounts on a case by case basis, considering changes in the financial position of a customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. Although we have encountered isolated credit concerns related to independent oil companies, we are not aware of any significant credit risks related to our customer base and do not generally require collateral or other security to support customer receivables.

We hold investments in debt and equity instruments of certain privately held companies as a result of certain dispositions of assets and equity interests or as a result of arrangements with certain suppliers. We monitor the financial condition of the investees on an ongoing basis to determine whether a valuation allowance is required.

Labor agreements—We require highly skilled personnel to operate our drilling units. We conduct extensive personnel recruiting, training and safety programs. At December 31, 2015, we had approximately 9,100 employees, including approximately 500 persons engaged through contract labor providers. Approximately 30 percent of our total workforce, working primarily in Angola, the U.K., Nigeria,

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Norway, Australia and Brazil 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.

Note 22—Operating Segments, Geographic Analysis and Major Customers

Operating segments—We operate in a single, global market for the provision of contract drilling services to our customers. The location of our rigs and the allocation of our resources to build or upgrade rigs are determined by the activities and needs of our customers.

Geographic analysis—Operating revenues for our continuing operations by country were as follows (in millions):

	Years ended December 31,		
	2015	2014	2013
Operating revenues			
U.S.	$ 1,891	$ 2,289	$ 2,382
U.K.	1,139	1,194	1,181
Norway	650	1,036	1,208
Other countries (a)	3,706	4,655	4,478
Total operating revenues	$ 7,386	$ 9,174	$ 9,249

(a) Other countries represent countries in which we operate that individually had operating revenues representing less than 10 percent of total operating revenues earned.

Long lived assets of our continuing operations by country were as follows (in millions):

	December 31,	
	2015	2014
Long-lived assets		
U.S.	$ 7,452	$ 7,080
Korea	2,048	1,535
Other countries (a)	11,318	12,923
Total long-lived assets	$ 20,818	$ 21,538

(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.

A substantial portion of our assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the revenues generated by such assets during the periods. Although we are organized under the laws of Switzerland, we do not conduct any operations and do not have operating revenues in Switzerland. At December 31, 2015 and 2014, the aggregate carrying amount of our long lived assets located in Switzerland was $2 million and $3 million, respectively.

Our international operations are subject to certain political and other uncertainties, including risks of war and civil disturbances or other market disrupting events, expropriation of equipment, repatriation of income or capital, taxation policies, and the general hazards associated with certain areas in which we operate.

Major customers—For the year ended December 31, 2015, Chevron Corporation (together with its affiliates, “Chevron”) and Royal Dutch Shell plc, together with its affiliates, accounted for approximately 14 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. For the year ended December 31, 2014, Chevron and BP accounted for approximately 11 percent and nine percent, respectively, of our consolidated operating revenues from continuing operations. For the year ended December 31, 2013, Chevron and BP accounted for approximately 12 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations.

Note 23—Condensed Consolidating Financial Information

Transocean Inc., a wholly owned subsidiary of Transocean Ltd., is the issuer of certain notes and debentures, which have been guaranteed by Transocean Ltd. Transocean Ltd.’s guarantee of debt securities of Transocean Inc. is full and unconditional. Transocean Ltd. is not subject to any significant restrictions on its ability to obtain funds by dividends, loans or return of capital distributions from its consolidated subsidiaries.

The following tables present condensed consolidating financial information for (a) Transocean Ltd. (the “Parent Guarantor”), (b) Transocean Inc. (the “Subsidiary Issuer”), and (c) the other direct and indirect wholly owned and partially owned subsidiaries of the Parent Guarantor (the “Other Subsidiaries”), none of which guarantee any indebtedness of the Subsidiary Issuer. The condensed consolidating

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financial information may not be indicative of the results of operations, financial position or cash flows had the subsidiaries operated as independent entities.

We have corrected the presentation of our condensed consolidating statements of comprehensive income (loss) for the years ended December 31, 2014 and 2013, and our condensed consolidating balance sheets as of December 31, 2014 to properly reflect the equity in losses of certain Other Subsidiaries resulting from our loss on impairment of goodwill that was previously presented in the statement of operations of the Subsidiary Issuer. We have also corrected the presentation of other amounts related to the capitalization of interest expense previously disclosed in the statement of operations of the Other Subsidiaries. In the year ended December 31, 2014, the effect of these corrections reduced net loss and total comprehensive loss for the Subsidiary Issuer by $286 million, increased net loss and total comprehensive loss for the Other Subsidiaries by $133 million and decreased the consolidating adjustments by $153 million. In the year ended December 31, 2013, the effect of these corrections reduced net income and total comprehensive income for the Other Subsidiaries by $63 million and, correspondingly, increased the consolidating adjustments. The corrections also had a corresponding effect on the investments in affiliates of the Subsidiary Issuer and the total equity of the Other Subsidiaries. Additionally, on the balance sheet as of December 31, 2014, we reclassified certain elimination entries from the consolidating adjustments column, eliminating activity among the other subsidiary companies. Such reclassification reduced the consolidating adjustments by $13.0 billion with a corresponding reduction to the respective balances of the Other Subsidiaries. These changes had no effect on the consolidated statements of operations, the consolidated balance sheets or the consolidated or consolidating statements of cash flows, as previously reported.

The following tables include the consolidating adjustments necessary to present the condensed financial statements on a consolidated basis (in millions):

	Year ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 7,392	$ (6)	$ 7,386
Cost and expenses	23	6	4,088	(6)	4,111
Loss on impairment	—	—	(1,867)	—	(1,867)
Loss on disposal of assets, net	—	—	(28)	—	(28)
Operating income (loss)	(23)	(6)	1,409	—	1,380
Other income (expense), net					
Interest income (expense), net	(7)	(593)	190	—	(410)
Equity in earnings	821	1,387	—	(2,208)	—
Other, net	—	57	3	—	60
	814	851	193	(2,208)	(350)
Income from continuing operations before income tax expense	791	845	1,602	(2,208)	1,030
Income tax expense	—	—	206	—	206
Income from continuing operations	791	845	1,396	(2,208)	824
Income from discontinued operations, net of tax	—	1	1	—	2

Net income	791	846	1,397	(2,208)	826
Net income attributable to noncontrolling interest	—	—	35	—	35
Net income attributable to controlling interest	791	846	1,362	(2,208)	791
Other comprehensive income (loss) before income taxes	—	(3)	89	—	86
Income taxes related to other comprehensive loss	—	—	(16)	—	(16)
Other comprehensive income (loss), net of income taxes	—	(3)	73	—	70
Total comprehensive income	791	843	1,470	(2,208)	896
Total comprehensive income attributable to noncontrolling interest	—	—	35	—	35
Total comprehensive income attributable to controlling interest	$ 791	$ 843	$ 1,435	$ (2,208)	$ 861

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	Year ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 9,181	$ (7)	$ 9,174
Cost and expenses	25	17	6,448	(7)	6,483
Loss on impairment	—	—	(4,043)	—	(4,043)
Loss on disposal of assets, net	—	—	(26)	—	(26)
Operating loss	(25)	(17)	(1,336)	—	(1,378)
Other income (expense), net					
Interest income (expense), net	(10)	(442)	8	—	(444)
Equity in earnings	(1,878)	(1,093)	—	2,971	—
Other, net	—	38	(16)	—	22
	(1,888)	(1,497)	(8)	2,971	(422)
Loss from continuing operations before income tax expense	(1,913)	(1,514)	(1,344)	2,971	(1,800)
Income tax expense	—	—	146	—	146
Loss from continuing operations	(1,913)	(1,514)	(1,490)	2,971	(1,946)
Loss from discontinued operations, net of tax	—	(13)	(7)	—	(20)
Net loss	(1,913)	(1,527)	(1,497)	2,971	(1,966)
Net loss attributable to noncontrolling interest	—	—	(53)	—	(53)
Net loss attributable to controlling interest	(1,913)	(1,527)	(1,444)	2,971	(1,913)
Other comprehensive income (loss) before income taxes	9	(76)	(88)	—	(155)
Income taxes related to other comprehensive income	—	—	13	—	13
Other comprehensive income (loss), net of income taxes	9	(76)	(75)	—	(142)
Total comprehensive loss	(1,904)	(1,603)	(1,572)	2,971	(2,108)
Total comprehensive loss attributable to noncontrolling interest	—	—	(53)	—	(53)
Total comprehensive loss attributable to controlling interest	$ (1,904)	$ (1,603)	$ (1,519)	$ 2,971	$ (2,055)

	Year ended December 31, 2013				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 9,251	$ (2)	$ 9,249
Cost and expenses	29	9	6,922	(2)	6,958
Loss on impairment	—	—	(81)	—	(81)
Gain on disposal of assets, net	—	—	7	—	7
Operating income (loss)	(29)	(9)	2,255	—	2,217
Other income (expense), net					
Interest income (expense), net	(15)	(475)	(42)	—	(532)
Equity in earnings	1,450	2,049	—	(3,499)	—
Other, net	1	(15)	(15)	—	(29)
	1,436	1,559	(57)	(3,499)	(561)
Income from continuing operations before income tax expense	1,407	1,550	2,198	(3,499)	1,656
Income tax expense	—	—	258	—	258
Income from continuing operations	1,407	1,550	1,940	(3,499)	1,398
Income (loss) from discontinued operations, net of tax	—	(97)	106	—	9
Net income	1,407	1,453	2,046	(3,499)	1,407
Net income attributable to noncontrolling interest	—	—	—	—	—
Net income attributable to controlling interest	1,407	1,453	2,046	(3,499)	1,407
Other comprehensive income before income taxes	3	238	19	—	260
Income taxes related to other comprehensive loss	—	—	2	—	2
Other comprehensive income, net of income taxes	3	238	21	—	262
Total comprehensive income	1,410	1,691	2,067	(3,499)	1,669
Total comprehensive income attributable to noncontrolling interest	—	—	3	—	3
Total comprehensive income attributable to controlling interest	$ 1,410	$ 1,691	$ 2,064	$ (3,499)	1,666

TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

	December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 1	$ 460	$ 1,878	$ —	$ 2,339
Other current assets	4	812	2,775	(1,145)	2,446
Total current assets	5	1,272	4,653	(1,145)	4,785
Property and equipment, net	—	—	20,818	—	20,818
Investment in affiliates	14,526	29,422	—	(43,948)	—
Other assets	—	4,845	14,245	(18,364)	726
Total assets	14,531	35,539	39,716	(63,457)	26,329
Liabilities and equity					
Debt due within one year	—	973	120	—	1,093
Other current liabilities	15	401	2,305	(1,145)	1,576
Total current liabilities	15	1,374	2,425	(1,145)	2,669
Long-term debt	—	19,954	5,807	(18,364)	7,397
Other long-term liabilities	18	290	1,139	—	1,447
Total long-term liabilities	18	20,244	6,946	(18,364)	8,844
Commitments and contingencies					
Redeemable noncontrolling interest	—	—	8	—	8
Total equity	14,498	13,921	30,337	(43,948)	14,808
Total liabilities and equity	$ 14,531	$ 35,539	$ 39,716	$ (63,457)	$ 26,329

	December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 16	$ 842	$ 1,777	$ —	$ 2,635
Other current assets	12	757	3,570	(1,134)	3,205
Total current assets	28	1,599	5,347	(1,134)	5,840
Property and equipment, net	—	—	21,538	—	21,538
Investment in affiliates	13,952	30,923	—	(44,875)	—
Other assets	—	3,858	14,742	(17,407)	1,193
Total assets	13,980	36,380	41,627	(63,416)	28,571

Liabilities and equity					
Debt due within one year	—	897	135	—	1,032
Other current liabilities	287	473	3,111	(1,134)	2,737
Total current liabilities	287	1,370	3,246	(1,134)	3,769
Long-term debt	—	21,446	4,980	(17,407)	9,019
Other long-term liabilities	22	280	1,488	—	1,790
Total long-term liabilities	22	21,726	6,468	(17,407)	10,809
Commitments and contingencies					
Redeemable noncontrolling interest	—	—	11	—	11
Total equity	13,671	13,284	31,902	(44,875)	13,982
Total liabilities and equity	$ 13,980	$ 36,380	$ 41,627	$ (63,416)	$ 28,571

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

	Year ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (18)	$ (617)	$ 4,080	$ —	$ 3,445
Cash flows from investing activities					
Capital expenditures	—	—	(2,001)	—	(2,001)
Proceeds from disposal of assets, net	—	—	51	—	51
Proceeds from disposal of assets in discontinued operations, net	—	—	3	—	3
Proceeds from repayment of loans receivable	—	—	15	—	15
Investing activities with affiliates, net	—	(1,942)	(3,532)	5,474	—
Net cash used in investing activities	—	(1,942)	(5,464)	5,474	(1,932)
Cash flows from financing activities					
Repayments of debt	—	(1,372)	(134)	—	(1,506)
Proceeds from restricted cash investments	—	—	110	—	110
Distribution of qualifying additional paid-in capital	(381)	—	—	—	(381)
Distribution to holders of noncontrolling interest	—	—	(29)	—	(29)
Financing activities with affiliates, net	387	3,549	1,538	(5,474)	—
Other, net	(3)	—	—	—	(3)
Net cash provided by (used in) financing activities	3	2,177	1,485	(5,474)	(1,809)
Net increase (decrease) in cash and cash equivalents	(15)	(382)	101	—	(296)
Cash and cash equivalents at beginning of period	16	842	1,777	—	2,635
Cash and cash equivalents at end of period	$ 1	$ 460	$ 1,878	$ —	$ 2,339

	Year ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ 801	$ 1,362	$ 57	$ —	$ 2,220

Cash flows from investing activities					
Capital expenditures	—	—	(2,165)	—	(2,165)
Proceeds from disposal of assets, net	—	—	215	—	215
Proceeds from disposal of assets in discontinued operations, net	—	—	35	—	35
Proceeds from repayment of notes and loans receivable	—	—	101	—	101
Investment in loans receivable	—	—	(15)	—	(15)
Investing activities with affiliates, net	—	(2,520)	(379)	2,899	—
Other, net	—	—	1	—	1
Net cash used in investing activities	—	(2,520)	(2,207)	2,899	(1,828)
Cash flows from financing activities					
Repayments of debt	—	—	(539)	—	(539)
Proceeds from restricted cash investments	—	—	176	—	176
Proceeds from sale of noncontrolling interest	—	—	443	—	443
Deposits to restricted cash investments	—	—	(20)	—	(20)
Issue costs for sale of noncontrolling interest	—	—	(26)	—	(26)
Distribution of qualifying additional paid-in capital	(1,018)	—	—	—	(1,018)
Distributions to holders of noncontrolling interest	—	—	(5)	—	(5)
Financing activities with affiliates, net	236	389	2,274	(2,899)	—
Other, net	(7)	(6)	2	—	(11)
Net cash provided by (used in) financing activities	(789)	383	2,305	(2,899)	(1,000)
Net decrease in cash and cash equivalents	12	(775)	155	—	(608)
Cash and cash equivalents at beginning of period	4	1,617	1,622	—	3,243
Cash and cash equivalents at end of period	$ 16	$ 842	$ 1,777	$ —	$ 2,635

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TRANSOCEAN LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—continued

	Year ended December 31, 2013				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (51)	$ (661)	$ 2,630	$ —	$ 1,918
Cash flows from investing activities					
Capital expenditures	—	—	(2,238)	—	(2,238)
Proceeds from disposal of assets, net	—	—	174	—	174
Proceeds from disposal of assets in discontinued operations, net	—	—	204	—	204
Proceeds from sale of preference shares	—	185	—	—	185
Proceeds from repayment of notes receivable	—	—	17	—	17
Investing activities with affiliates, net	—	(1,461)	(1,100)	2,561	—
Net cash used in investing activities	—	(1,276)	(2,943)	2,561	(1,658)
Cash flows from financing activities					
Repayments of debt	—	(562)	(1,130)	—	(1,692)
Proceeds from restricted cash investments	—	—	298	—	298
Deposits to restricted cash investments	—	—	(119)	—	(119)
Distribution of qualifying additional paid-in capital	(606)	—	—	—	(606)
Financing activities with affiliates, net	643	978	940	(2,561)	—
Other, net	(6)	(17)	(9)	—	(32)
Net cash provided by (used in) financing activities	31	399	(20)	(2,561)	(2,151)
Net decrease in cash and cash equivalents	(20)	(1,538)	(333)	—	(1,891)
Cash and cash equivalents at beginning of period	24	3,155	1,955	—	5,134
Cash and cash equivalents at end of period	$ 4	$ 1,617	$ 1,622	$ —	$ 3,243

Note 24—Quarterly Results (Unaudited)

	Three months ended			
	March 31,	June 30,	September 30,	December 31,
	(In millions, except per share data)			
2015				
Operating revenues	$ 2,043	$ 1,884	$ 1,608	$ 1,851

Operating income (loss) (a)	(321)	506	445	750
Income (loss) from continuing operations (a)	(467)	347	327	617
Net income (loss) (a)	(469)	348	330	617
Net income (loss) attributable to controlling interest (a)	(483)	342	321	611
Per share earnings (loss) from continuing operations				
Basic	$ (1.32)	$ 0.93	$ 0.87	$ 1.66
Diluted	$ (1.32)	$ 0.93	$ 0.87	$ 1.66
Weighted-average shares outstanding				
Basic	363	363	364	364
Diluted	363	363	364	364
2014				
Operating revenues	$ 2,339	$ 2,328	$ 2,270	$ 2,237
Operating income (b)	672	765	(2,168)	(647)
Income from continuing operations (b)	474	604	(2,262)	(762)
Net income (b)	466	597	(2,263)	(766)
Net income attributable to controlling interest (b)	456	587	(2,217)	(739)
Per share earnings from continuing operations				
Basic	$ 1.27	$ 1.63	$ (6.12)	$ (2.03)
Diluted	$ 1.27	$ 1.63	$ (6.12)	$ (2.03)
Weighted-average shares outstanding				
Basic	361	362	362	362
Diluted	361	362	362	362

(a) First quarter, second quarter, third quarter and fourth quarter included an aggregate loss of $692 million associated with the impairment of certain drilling units classified as assets held for sale. First quarter and second quarter included a loss of $507 million and $668 million, respectively, associated with the impairment of our deepwater asset group and midwater asset group, respectively. Second quarter included income of $788 million associated with recoveries of previously incurred costs associated with the Macondo well incident. Third quarter and fourth quarter included an aggregate net gain of $23 million associated with the retirement of debt. See Note 5—Impairments, Note 9—Drilling Fleet and Note 14—Commitments and Contingencies.

(b) First quarter and third quarter included a loss of $3 million associated with loss contingencies and income of $22 million associated with insurance recoveries, net, respectively, related to the Macondo well incident. First, third and fourth quarters included an aggregate loss of $268 million associated with the impairment of certain drilling units classified as assets held for sale. Third quarter included a loss of $788 million associated with the impairment of the deepwater floater asset group. Third quarter and fourth quarter included an aggregate loss of $3.0 billion associated with the full impairment of the remaining carrying amount of our goodwill. See Note 5—Impairments, Note 9—Drilling Fleet and Note 14—Commitments and Contingencies.

Note 25—Subsequent Events

Norway tax investigations and trial—Subsequent to December 31, 2015, 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 regarding disclosures in our Norwegian tax returns related to a dividend payment in 2001 and regarding disclosures in our Norwegian tax returns related to an intercompany rig sale in 1999 and certain inaccuracies in Norwegian statutory financial statements for the years ended December 31, 1996 through 2001. As a result, no criminal charges remain outstanding for any of the previously reported Norway tax investigations or trials, and all of our subsidiaries and external advisors have been fully acquitted of all criminal charges.

Par value reduction and shares held in treasury—Following a formal notification to creditors and establishment of a public deed of compliance, the reduction of our par value and the cancellation of our shares held in treasury, which were approved at our extraordinary general meeting held on October 29, 2015, became effective as of January 7, 2016 upon registration in the commercial register.

Postemployment benefit plans—Subsequent to December 31, 2015, we and the plan trustees mutually agreed to cease accruing benefits under the U.K. Plan, effective March 31, 2016.

Derivatives and hedging—Subsequent to December 31, 2015, we terminated our interest rate swaps previously designated as a fair value hedge of the 6.0% Senior Notes, and we received an aggregate net cash payment of $11 million in connection with the settlement.

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

We have not had a change in or disagreement with our accountants within 24 months prior to the date of our most recent financial statements or in any period subsequent to such date.

Item 9A.Controls and Procedures

Disclosure controls and procedures—We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures, as defined in the Exchange Act, Rules 13a 15 and 15d 15, were effective as of December 31, 2015 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms.

Internal control over financial reporting—There were no changes to our internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. See "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" included in Item 8 of this annual report.

Item 9B.Other Information

None.

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PART III

Item 10.Directors, Executive Officers and Corporate Governance

Item 11.Executive Compensation

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

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

Item 14.Principal Accounting Fees and Services

The information required by Items 10, 11, 12, 13 and 14 is incorporated herein by reference to our definitive proxy statement for our 2016 annual general meeting of shareholders, which will be filed with the U.S. Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of December 31, 2015. Certain information with respect to our executive officers is set forth in Item 4 of this annual report under the caption "Executive Officers of the Registrant."

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PART IV

Item 15.Exhibits and Financial Statement Schedules

(a)Index to Financial Statements, Financial Statement Schedules and Exhibits

(1) Index to Financial Statements

Included in Part II of this report:	Page
Management's Report on Internal Control Over Financial Reporting	55
Reports of Independent Registered Public Accounting Firm	56
Consolidated Statements of Operations	58
Consolidated Statements of Comprehensive Income (Loss)	59
Consolidated Balance Sheets	60
Consolidated Statements of Equity	61
Consolidated Statements of Cash Flows	62
Notes to Consolidated Financial Statements	63

Financial statements of unconsolidated subsidiaries are not presented herein because such subsidiaries do not meet the significance test.

(2) Financial Statement Schedules

Transocean Ltd. and Subsidiaries

Schedule II Valuation and Qualifying Accounts

(In millions)

	Balance at beginning of period	Additions: Charge to cost and expenses	Additions: Charge to other accounts -describe	Deductions -describe		Balance at end of period
Year ended December 31, 2013						
Reserves and allowances deducted from asset accounts:						
Allowance for doubtful accounts receivable	$ 20	$ —	$ —	$ 6	(a)	$ 14
Allowance for obsolete materials and supplies	66	17	—	3	(b)	80
Valuation allowance on deferred tax assets	210	37	—	—		247

Year ended December 31, 2014

Reserves and allowances deducted from asset accounts:						
Allowance for doubtful accounts receivable	$ 14	$ —	$ —	$ —		$ 14
Allowance for obsolete materials and supplies	80	29	—	—		109
Valuation allowance on deferred tax assets	247	93	—	—		340
Year ended December 31, 2015						
Reserves and allowances deducted from asset accounts:						
Allowance for doubtful accounts receivable	$ 14	$ —	$ —	$ 14	(a)	$ —
Allowance for obsolete materials and supplies	109	62	—	23	(b)	148
Valuation allowance on deferred tax assets	340	34	—	—		374

(a) Uncollectible accounts receivable written off, net of recoveries.

(b) Amount related to sale of rigs and related equipment.

Other schedules are omitted either because they are not required or are not applicable or because the required information is included in the financial statements or notes thereto.

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(3) Exhibits

The following exhibits are filed in connection with this Report:

Number	Description
† 3.1	Articles of Association of Transocean Ltd.
3.2	Organizational Regulations of Transocean Ltd. (incorporated by reference to Exhibit 3.2 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 000 53533) for the quarter ended September 30, 2014)
4.1	Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Offshore Inc.'s Current Report on Form 8 K (Commission File No. 001 07746) filed on April 30, 1997)
4.2	First Supplemental Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee, supplementing the Indenture dated as of April 15, 1997 (incorporated by reference to Exhibit 4.2 to Transocean Offshore Inc.'s Current Report on Form 8 K (Commission File No. 001 07746) filed on April 30, 1997)
4.3	Second Supplemental Indenture dated as of May 14, 1999 between Transocean Offshore (Texas) Inc., Transocean Offshore Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Transocean Offshore Inc.'s Post Effective Amendment No. 1 to Registration Statement on Form S 3 (Registration No. 333 59001 99))
4.4	Fifth Supplemental Indenture, dated as of December 18, 2008, among Transocean Ltd., Transocean Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.4 to Transocean Ltd.'s Current Report on Form 8 K filed on December 19, 2008)
4.5	Form of 7.45% Notes due April 15, 2027 (incorporated by reference to Exhibit 4.3 to Transocean Offshore Inc.'s Current Report on Form 8 K (Commission File No. 001 07746) filed on April 30, 1997)
4.6	Form of 8.00% Debentures due April 15, 2027 (incorporated by reference to Exhibit 4.4 to Transocean Offshore Inc.'s Current Report on Form 8 K (Commission File No. 001 07746) filed on April 30, 1997)
4.7	Officers' Certificate establishing the terms of the 7.50% Note due April 15, 2031 (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on April 9, 2001)
4.8	Officers' Certificate establishing the terms of the 7.375% Notes due 2018 (incorporated by reference to Exhibit 4.14 to Transocean Sedco Forex Inc.'s Annual Report on Form 10 K (Commission File No. 333 75899) for the fiscal year ended December 31, 2001)
4.9	Indenture dated as of September 1, 1997, between Global Marine Inc. and Wilmington Trust Company, as Trustee, relating to Debt Securities of Global Marine Inc. (incorporated by reference to Exhibit 4.1 of Global Marine Inc.'s Registration Statement on Form S 4 (No. 333 39033) filed on October 30, 1997); First Supplemental Indenture dated as of June 23, 2000 (incorporated by reference to Exhibit 4.2 of Global Marine Inc.'s Quarterly Report on Form 10 Q (Commission File No. 1 5471) for the quarter ended June 30, 2000); Second Supplemental Indenture dated as of November 20, 2001 (incorporated by reference to Exhibit 4.2 to GlobalSantaFe Corporation's Annual Report on Form 10 K (Commission File No. 001 14634) for the year ended December 31, 2004)
4.10	Form of 7% Note Due 2028 (incorporated by reference to Exhibit 4.2 of Global Marine Inc.'s Current Report on Form 8 K (Commission File No. 1 5471) filed on May 22, 1998)
4.11	Terms of 7% Note Due 2028 (incorporated by reference to Exhibit 4.1 of Global Marine Inc.'s Current Report on Form 8 K (Commission File No. 1 5471) filed on May 22, 1998)
4.12	Senior Indenture, dated as of December 11, 2007, between Transocean Inc. and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.36 to Transocean Inc.'s Annual Report on

Form 10 K (Commission File No. 333 75899) for the year ended December 31, 2007)

4.13 First Supplemental Indenture, dated as of December 11, 2007, between Transocean Inc. and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.37 to Transocean Inc.'s Annual Report on Form 10 K (Commission File No. 333 75899) for the year ended December 31, 2007)

4.14 Third Supplemental Indenture, dated as of December 18, 2008, among Transocean Ltd., Transocean Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on December 19, 2008)

4.15 Fourth Supplemental Indenture, dated as of September 21, 2010, among Transocean Ltd., Transocean Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 000 53533) for the quarter ended September 30, 2010)

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	4.16	Fifth Supplemental Indenture, dated as of December 5, 2011, among Transocean Ltd., Transocean Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on December 5, 2011)
	4.17	Sixth Supplemental Indenture, dated as of September 13, 2012, among Transocean Inc., Transocean Ltd. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on September 13, 2012)
	4.18	Credit Agreement dated June 30, 2014 among Transocean Inc., the lenders parties thereto and JPMorgan Chase Bank, N.A., as administrative agent, Citibank, N.A. and DNB Bank, ASA, New York Branch, as co syndication agents, and The Bank of Tokyo Mitsubishi UFJ, Ltd., Crédit Agricole Corporate and Investment Bank and Wells Fargo Bank, National Association, as co documentation agents (incorporated by reference to Exhibit 4.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on July 2, 2014)
	4.19	Guarantee Agreement dated June 30, 2014 among Transocean Ltd. and JPMorgan Chase Bank, N.A., as administrative agent under the Credit Agreement (incorporated by reference to Exhibit 4.2 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on July 2, 2014)
	10.1	Nomination and Standstill Agreement dated as of November 10, 2013 by and between Transocean Ltd., High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Partners Master Fund II LP, Icahn Partners Master Fund III LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital LP, Icahn Onshore LP, Icahn Offshore LP, Beckton Corp., Samuel Merksamer and Vincent Intrieri (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on November 12, 2013)
*	10.2	Long Term Incentive Plan of Transocean Ltd. (as amended and restated as of February 12, 2009) (incorporated by reference to Exhibit 10.5 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
*	10.3	First Amendment to Long Term Incentive Plan of Transocean Ltd. (as amended and restated as of February 12, 2009) (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on May 22, 2013)
*	10.4	Deferred Compensation Plan of Transocean Offshore Inc., as amended and restated effective January 1, 2000 (incorporated by reference to Exhibit 10.10 to Transocean Sedco Forex Inc.'s Annual Report on Form 10 K (Commission File No. 333 75899) for the year ended December 31, 1999)
*	10.5	GlobalSantaFe Corporation Key Employee Deferred Compensation Plan effective January 1, 2001 and Amendment to GlobalSantaFe Corporation Key Employee Deferred Compensation Plan effective November 20, 2001 (incorporated by reference to Exhibit 10.33 to the GlobalSantaFe Corporation Annual Report on Form 10 K for the year ended December 31, 2004)
*	10.6	Amendment to Transocean Inc. Deferred Compensation Plan (incorporate by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on December 29, 2005)
	10.7	Master Separation Agreement dated February 4, 2004 by and among Transocean Inc., Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.2 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on March 3, 2004)
	10.8	Tax Sharing Agreement dated February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.3 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on March 3, 2004)
	10.9	Amended and Restated Tax Sharing Agreement effective as of February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on November 30, 2006)

*	10.10	Form of 2004 Performance Based Nonqualified Share Option Award Letter (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on February 15, 2005)
*	10.11	Form of 2004 Director Deferred Unit Award (incorporated by reference to Exhibit 10.4 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on February 15, 2005)
*	10.12	Form of 2008 Director Deferred Unit Award (incorporated by reference to Exhibit 10.20 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
*	10.13	Form of 2009 Director Deferred Unit Award (incorporated by reference to Exhibit 10.19 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2009)
† *	10.14	Terms and Conditions of 2013 Director Deferred Unit Award
† *	10.15	Terms and Conditions of 2014 Director Deferred Unit Award

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† *	10.16	Terms and Conditions of 2015 Director Restricted Share Unit Award
*	10.17	Performance Award and Cash Bonus Plan of Transocean Ltd. (incorporated by reference to Exhibit 10.21 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
*	10.18	Amendment to Performance Award and Cash Bonus Plan of Transocean Ltd. (incorporated by reference to Exhibit 10.20 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2012)
† *	10.19	Terms and Conditions of 2014 Executive Equity Award
† *	10.20	Terms and Conditions of 2015 Executive Equity Award
*	10.21	Terms and Conditions of the July 2008 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10 Q (Commission File No. 333 75899) for the quarter ended June 30, 2008)
*	10.22	Terms and Conditions of the February 2009 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.30 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
*	10.23	Terms and Conditions of the February 2012 Long Term Incentive Plan Award (incorporated by reference to Exhibit 10.28 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2011)
*	10.24	Transocean Ltd. Incentive Recoupment Policy (incorporated by reference to Exhibit 10.30 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2012)
	10.25	Form of Novation Agreement dated as of November 27, 2007 by and among GlobalSantaFe Corporation, Transocean Offshore Deepwater Drilling Inc. and certain executives (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on December 3, 2007)
*	10.26	Global Marine Inc. 1990 Non Employee Director Stock Option Plan (incorporated by reference to Exhibit 10.18 of Global Marine Inc.'s Annual Report on Form 10 K (Commission File No. 1 5471) for the year ended December 31, 1991); First Amendment (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10 Q (Commission File No. 1 5471) for the quarter ended June 30, 1995); Second Amendment (incorporated by reference to Exhibit 10.37 of Global Marine Inc.'s Annual Report on Form 10 K (Commission File No. 1 5471) for the year ended December 31, 1996)
*	10.27	1997 Long Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Registration Statement on Form S 8 (No. 333 7070) filed June 13, 1997); Amendment to 1997 Long Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20 F (Commission File No. 001 14634) for the calendar year ended December 31, 1998); Amendment to 1997 Long Term Incentive Plan dated December 1, 1999 (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20 F (Commission File No. 001 14634) for the calendar year ended December 31, 1999)
*	10.28	GlobalSantaFe Corporation 1998 Stock Option and Incentive Plan (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10 Q (Commission File No. 1 5471) for the quarter ended March 31, 1998); First Amendment (incorporated by reference to Exhibit 10.2 of Global Marine Inc.'s Quarterly Report on Form 10 Q (Commission File No. 1 5471) for the quarter ended June 30, 2000)
*	10.29	GlobalSantaFe Corporation 2001 Non Employee Director Stock Option and Incentive Plan (incorporated by reference to Exhibit 4.8 of GlobalSantaFe Corporation's Registration Statement on Form S 8 (No. 333 73878) filed November 21, 2001)
*	10.30	GlobalSantaFe Corporation 2001 Long Term Incentive Plan (incorporated by reference to Exhibit A to GlobalSantaFe Corporation's Quarterly Report on Form 10 Q (Commission File No. 001 14634) for the quarter ended June 30, 2001)
*	10.31	

	GlobalSantaFe 2003 Long Term Incentive Plan (as Amended and Restated Effective June 7, 2005) (incorporated by reference to Exhibit 10.4 to GlobalSantaFe Corporation's Quarterly Report on Form 10 Q (Commission File No. 001 14634) for the quarter ended June 30, 2005)
* 10.32	Transocean Ltd. Pension Equalization Plan, as amended and restated, effective January 1, 2009 (incorporated by reference to Exhibit 10.41 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
* 10.33	Transocean U.S. Supplemental Retirement Benefit Plan, as amended and restated, effective as of November 27, 2007 (incorporated by reference to Exhibit 10.11 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on December 3, 2007)

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*	10.34	GlobalSantaFe Corporation Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.1 to the GlobalSantaFe Corporation Quarterly Report on Form 10 Q for the quarter ended September 30, 2002)
*	10.35	Transocean U.S. Supplemental Savings Plan (incorporated by reference to Exhibit 10.44 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2008)
	10.36	Form of Indemnification Agreement entered into between Transocean Ltd. and each of its Directors and Executive Officers (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8 K (Commission File No. 333 75899) filed on October 10, 2008)
*	10.37	Form of Assignment Memorandum for Executive Officers (incorporated by reference to Exhibit 10.6 to Transocean Ltd.'s Current Report on Form 8 K filed on December 19, 2008)
	10.38	Drilling Contract between Vastar Resources, Inc. and R&B Falcon Drilling Co. dated December 9, 1998 with respect to Deepwater Horizon, as amended (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 000 53533) for the quarterly period ended June 30, 2010)
*	10.39	Executive Severance Benefit Policy (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on February 23, 2012)
*	10.40	Agreement with Gregory L. Cauthen (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on January 10, 2012)
*	10.41	First Amendment to Agreement with Gregory L. Cauthen (incorporated by reference to Exhibit 10.2 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on July 2, 2012)
*	10.42	Agreement with Gregory L. Cauthen effective as of April 25, 2013 (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on April 26, 2013)
*	10.43	Agreement with Allen M. Katz (incorporated by reference to Exhibit 10.55 to Transocean Ltd.'s Annual Report on Form 10 K (Commission File No. 000 53533) for the year ended December 31, 2012)
*	10.44	First Amendment to Employment Agreement with Allen M. Katz effective as of July 1, 2013 (incorporated by reference to Exhibit 10.3 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 000 53533) for the quarterly period ended June 30, 2013)
*	10.45	Second Amendment to Employment Agreement with Allen M. Katz effective as of January 1, 2014 and incorporated herein by reference
*	10.46	Agreement with Steven L. Newman (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on December 23, 2013)
*	10.47	Agreement with John Stobart (incorporated by reference to Exhibit 10.2 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on December 23, 2013)
*	10.48	Agreement with Esa Ikäheimonen (incorporated by reference to Exhibit 10.3 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on December 23, 2013)
*	10.49	Agreement with Ihab M. Toma (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on December 26, 2013)
	10.50	Omnibus Agreement dated August 5, 2014 among Transocean Ltd., Transocean Inc., Transocean Partners Holdings Limited, Transocean Partners LLC, Triton RIGP DCL Holding Limited, Triton RIGP DIN Holding Limited, Triton RIGP DD3 Holding Limited, Triton RIGP DCL Holdco Limited, Triton RIGP DIN Holdco Limited, Triton RIGP DD3 Holdco Limited, Transocean RIGP DCL Opco Limited, Transocean RIGP DIN Opco Limited, Transocean RIGP DD3 Opco Limited, Transocean RIGP DCL LLC, Transocean RIGP DIN LLC and Transocean RIGP DD3 LLC (incorporated by reference to Exhibit 10.1 to Transocean Partners LLC's Current Report on Form 8 K (Commission File No. 001 36584) filed on August 5, 2014)
*	10.51	Transocean Ltd. 2015 Long Term Incentive Plan (incorporated by reference to Annex B to Transocean Ltd.'s definitive proxy statement (Commission File No. 001 53533) filed on March 23, 2015)

*	10.52	Separation Agreement, dated March 31, 2015, among Transocean Ltd., Transocean Offshore Deepwater Drilling Inc. and Steven Newman (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 001 53533) filed on April 1, 2015)
*	10.53	Employment Agreement between Transocean Ltd. and Ian C. Strachan dated April 15, 2015, (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 001 53533) filed on April 16, 2015)
*	10.54	Employment Agreement among Transocean Ltd., Transocean Offshore Deepwater Drilling Inc. and Jeremy D. Thigpen dated April 21, 2015 (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 001 53533) filed on April 22, 2015)

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*	10.55	Employment Agreement among Transocean Ltd., Transocean Offshore Deepwater Drilling Inc. and Mark Mey dated May 27, 2015 (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 001 53533) filed on May 27, 2015)
*	10.56	Letter Agreement by and among Transocean Ltd., Transocean Management Ltd. and Esa Ikäheimonen dated July 21, 2015 (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 001 53533) filed on July 23, 2015)
	10.57	Term Sheet Agreement for a Transocean and PSC/DHEPDS Settlement, dated May 20, 2015, among Triton Asset Leasing GmbH, Transocean Deepwater Inc., Transocean Offshore Deepwater Drilling Inc., Transocean Holdings LLC, the Plaintiffs Steering Committee in MDL 2179, and the Deepwater Horizon Economic and Property Damages Settlement Class (incorporated by reference to Exhibit 10.3 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 001 53533) for the quarter ended June 30, 2015)
	10.58	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated May 20, 2015, among Transocean Offshore Deepwater Drilling Inc., Transocean Deepwater Inc., Transocean Holdings LLC, Triton Asset Leasing GmbH, BP Exploration and Production Inc. and BP America Production Co. (incorporated by reference to Exhibit 10.6 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 001 53533) for the quarter ended June 30, 2015)
	10.59	Transocean Punitive Damages and Assigned Claims Settlement Agreement, dated May 29, 2015, among Transocean Offshore Deepwater Drilling Inc., Transocean Deepwater Inc., Transocean Holdings LLC, Triton Asset Leasing GmbH, the Plaintiffs Steering Committee in MDL 2179, and the Deepwater Horizon Economic and Property Damages Settlement Class (incorporated by reference to Exhibit 10.7 to Transocean Ltd.'s Quarterly Report on Form 10 Q (Commission File No. 001 53533) for the quarter ended June 30, 2015)
† *	10.60	Employment Agreement among Transocean Ltd., Transocean Offshore Deepwater Drilling Inc. and John Stobart dated December 1, 2015
†	21	Subsidiaries of Transocean Ltd.
†	23.1	Consent of Ernst & Young LLP
†	24	Powers of Attorney
†	31.1	CEO Certification Pursuant to Section 302 of the Sarbanes Oxley Act of 2002
†	31.2	CFO Certification Pursuant to Section 302 of the Sarbanes Oxley Act of 2002
†	32.1	CEO Certification Pursuant to Section 906 of the Sarbanes Oxley Act of 2002
†	32.2	CFO Certification Pursuant to Section 906 of the Sarbanes Oxley Act of 2002
	99.2	Cooperation Guilty Plea Agreement by and among Transocean Deepwater Inc., Transocean Ltd. and the United States (incorporated by reference to Exhibit 99.2 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on January 3, 2013)
	99.3	Consent Decree by and among Triton Asset Leasing GmbH, Transocean Holdings LLC, Transocean Offshore Deepwater Drilling Inc., Transocean Deepwater Inc. and the United States (incorporated by reference to Exhibit 99.3 to Transocean Ltd.'s Current Report on Form 8 K (Commission File No. 000 53533) filed on January 3, 2013)
	99.4	Administrative Agreement by and among Transocean Deepwater Inc., Transocean Offshore Deepwater Drilling Inc., Triton Asset Leasing GmbH, Transocean Holdings, LLC and the United States Environmental Protection Agency dated effective as of February 25, 2013 and incorporated herein by reference
†	101.INS	XBRL Instance Document
†	101.SCH	XBRL Taxonomy Extension Schema
†	101.CAL	XBRL Taxonomy Extension Calculation Linkbase
†	101.DEF	XBRL Taxonomy Extension Definition Linkbase
†	101.LAB	XBRL Taxonomy Extension Label Linkbase

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†	101.PRE	XBRL Taxonomy Extension Presentation Linkbase

† Filed herewith.
* Compensatory plan or arrangement.

Exhibits listed above as previously having been filed with the U.S. Securities and Exchange Commission (“SEC”) are incorporated herein by reference pursuant to Rule 12b 32 under the Securities Exchange Act of 1934 and made a part hereof with the same effect as if filed herewith.

Certain instruments relating to our long term debt and our subsidiaries have not been filed as exhibits since the total amount of securities authorized under any such instrument does not exceed 10 percent of our total assets and our subsidiaries on a consolidated basis. We agree to furnish a copy of each such instrument to the SEC upon request.

Certain agreements filed as exhibits to this Report may contain representations and warranties by the parties to such agreements. These representations and warranties have been made solely for the benefit of the parties to such agreements and (1) may be intended not as statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate, (2) may have been qualified by certain disclosures that were made to other parties in connection with the negotiation of such agreements, which disclosures are not reflected in such agreements, and (3) may apply standards of materiality in a way that is different from what may be viewed as material to investors.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 24, 2016.

TRANSOCEAN LTD.

By: /s/ Mark L. Mey
Mark L. Mey
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

By: /s/ David Tonnel
David Tonnel
Senior Vice President, Supply Chain and Corporate Controller
(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on February 24, 2016.

Signature	Title
* Merrill A. “Pete” Miller, Jr	Chairman of the Board of Directors
/s/ Jeremy D. Thigpen Jeremy D. Thigpen	President and Chief Executive Officer (Principal Executive Officer)
/s/ Mark L. Mey Mark L. Mey	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ David Tonnel David Tonnel	Senior Vice President, Supply Chain and Corporate Controller (Principal Accounting Officer)
* Glyn Barker	Director

* Vanessa C.L. Chang	Director
* Frederico F. Curado	Director
* Chad Deaton	Director
* Tan Ek Kia	Director
* Vincent J. Intrieri	Director
* Samuel Merksamer	Director
* Martin B. McNamara	Director
* Edward R. Muller	Director

By: /s/ David Tonnel
(Attorney in Fact)