Transocean Ltd.
Form 10-K
February 27, 2014

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

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2013

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 (State or other jurisdiction of incorporation or organization)	98-0599916 (I.R.S. Employer Identification No.)
10 Chemin de Blandonnet Vernier, Switzerland (Address of principal executive offices)	1214 (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 15.00 per	New York Stock Exchange

share 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 þ 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 þ

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 þ 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 þ 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 þ 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 þ

As of June 30, 2013, 360,244,947 shares were outstanding and the aggregate market value of shares held by non-affiliates was approximately $17.3 billion (based on the reported closing market price of the shares of Transocean Ltd. on June 28, 2013 of $47.95 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 18, 2014, 361,024,286 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, 2013, for its 2014 annual general meeting of shareholders, are incorporated by reference into Part III of this Form 10-K.

TRANSOCEAN LTD. AND SUBSIDIARIES
INDEX TO ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2013

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 Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements in this annual report include, but are not limited to, statements about the following subjects:

§ the impact of the Macondo well incident, claims, settlement and related matters,

§ our results of operations and cash flow from operations, including revenues, revenue efficiency, costs and expenses,

§ the offshore drilling market, including the impact of enhanced regulations in the jurisdictions in which we operate, supply and demand, utilization rates, dayrates, customer drilling programs, commodity prices, stacking of rigs, reactivation of rigs, effects of new rigs on the market and effects of declines in commodity prices and the downturn 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, contract awards and rig mobilizations,

§ liquidity and adequacy of cash flows for our obligations,

§ debt levels, including impacts of a financial and economic downturn,

§ uses of excess cash, including the payment of dividends and other distributions, share repurchases and debt retirement, including the amounts, timing and, as applicable shareholder proposals or approvals associated with uses of excess cash,

§ 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,

§ the cost and timing of acquisitions and the proceeds and timing of dispositions,

§ the timing, terms and results of our planned initial public offering of a master limited partnership,

§ the results and timing of our organizational efficiency initiative, including related costs and expenses,

§ 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 United States ("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”,

§ 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,

§ shipyard, construction and other delays,

§ the results of meetings of our shareholders,

§ increased political and civil unrest,

§ 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, and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by law.

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 18, 2014, we owned or had partial ownership interests in and operated 79 mobile offshore drilling units associated with our continuing operations. As of February 18, 2014, our fleet consisted of 46 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 22 Midwater Floaters and 11 High-Specification Jackups. At February 18, 2014, we also had seven 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." For information about the revenues, operating income, assets and other information related to our business, our segments and the geographic areas in which we operate, see "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 23—Operating Segments, Geographical Analysis and Major Customers."

Recent Developments

In February 2014, in connection with our efforts to discontinue non-strategic operations, we completed the sale of Advanced Drilling Technology International Limited, a U.K. company that performs drilling management services in the North Sea. Following the completion of the sale transaction, we agreed to provide a $15 million working capital line of credit to the buyer for up to two years. We have also provided a limited guarantee in favor of one customer through expiration of the current drilling project, which is expected to be completed in the fourth quarter of 2014. The disposal of this component of our business results in the discontinuation of our drilling management services operating segment in the year ending December 31, 2014.

In November 2012, in connection with our efforts to dispose of non-strategic assets and reduce our exposure to low-specification drilling units, we completed the sale of 37 standard jackups and one swamp barge to Shelf Drilling Holdings, Ltd. ("Shelf Drilling"). For a transition period following the completion of the sale transactions, we agreed to continue to operate a substantial portion of the standard jackups on behalf of Shelf Drilling and to provide certain other transition services to Shelf Drilling. As of February 18, 2014, under operating agreements, we continue to operate seven standard jackups on behalf of Shelf Drilling until the expiration of the underlying drilling contracts, which is expected in mid-2014. In addition, under a transition services agreement, we continue to provide certain transition services, which we expect to end in mid-2014. See "Part II. Item 8. Financial Statements and Supplementary

Data—Notes to Consolidated Financial Statements—Note 7—Discontinued Operations."

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 pipe 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 load capacity than early generation semisubmersible rigs. This enables them to carry more supplies on board, which often makes them better suited for drilling in remote locations where resupply is more difficult. However, drillships are generally limited to operations in calmer water conditions than those in which semisubmersibles can operate. We have 10 Ultra-Deepwater drillships in operation that are, and seven 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 single derrick to allow these drillships to perform simultaneous drilling tasks in a parallel rather than 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, five of our seven newbuild drillships under construction will be outfitted to accommodate a future upgrade to a 20,000 pounds per square inch (“psi”) blowout preventer.

Semisubmersibles are floating vessels that can be submerged by means of a water ballast system such that the lower hulls 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 better suited than drillships for operations in rougher water conditions. We have two custom-designed, high-capacity 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 24 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) “High-Specification Floaters,” consisting of our “Ultra-Deepwater Floaters,” “Deepwater Floaters” and “Harsh Environment Floaters,” (2) “Midwater Floaters” and (3) “High-Specification Jackups”.

High-Specification Floaters are specialized offshore drilling units that we categorize into three sub-classifications based on their capabilities. Ultra-Deepwater Floaters are equipped with high-pressure mud pumps and are capable of drilling in water depths of 7,500 feet or greater. Deepwater Floaters are generally those other semisubmersible rigs and drillships capable of drilling in water depths between 4,500 and 7,500 feet. 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. 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 18, 2014, we owned and operated a fleet of 79 rigs, excluding rigs under construction, as follows:

§ 46 High-Specification Floaters, which are comprised of:

§ 27 Ultra-Deepwater Floaters;

§ 12 Deepwater Floaters; and

§ Seven Harsh Environment Floaters;

§ 22 Midwater Floaters; and

§ 11 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 at all.

Drilling units—The following tables, presented as of February 18, 2014, 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 18, 2014, 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 joint venture companies and (2) Petrobras 10000, which is subject to a capital lease through August 2029.

Rigs Under Construction (12)

Name	Type	Expected completion	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Ultra-Deepwater Floaters					
Deepwater Asgard	HSD	1Q 2014	12,000	40,000	Indonesia
Deepwater Invictus	HSD	3Q 2014	12,000	40,000	U.S. Gulf
Deepwater Thalassa	HSD	1Q 2016	12,000	40,000	To be determined
Deepwater Proteus	HSD	2Q 2016	12,000	40,000	To be determined
Deepwater Pontus	HSD	1Q 2017	12,000	40,000	To be determined
Deepwater Poseidon	HSD	2Q 2017	12,000	40,000	To be determined
Deepwater Conqueror	HSD	4Q 2016	12,000	40,000	U.S. Gulf
High-Specification Jackups					
High-Specification Jackup TBN1	Jackup	1Q 2016	400	35,000	To be determined
High-Specification Jackup TBN2	Jackup	3Q 2016	400	35,000	To be determined
High-Specification Jackup TBN3	Jackup	4Q 2016	400	35,000	To be determined

High-Specification Jackup TBN4	Jackup	1Q 2017	400	35,000	To be determined
High-Specification Jackup TBN5	Jackup	3Q 2017	400	35,000	To be determined

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"HSD" means high-specification drillship.

High-Specification Floaters (46)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Location
Ultra-Deepwater Floaters (27)					
Discoverer Clear Leader (b) (c) (d)	HSD	2009	12,000	40,000	U.S. Gulf
Discoverer Americas (b) (c) (d) (e)	HSD	2009	12,000	40,000	Tanzania
Discoverer Inspiration (b) (c) (d) (e)	HSD	2010	12,000	40,000	U.S. Gulf
Deepwater Champion (b) (c) (e)	HSD	2011	12,000	40,000	U.S. Gulf
Petrobras 10000 (b) (c)	HSD	2009	12,000	37,500	Brazil
Dhirubhai Deepwater KG1 (b)	HSD	2009	12,000	35,000	India
Dhirubhai Deepwater KG2 (b)	HSD	2010	12,000	35,000	India
Discoverer India (b) (c) (d)	HSD	2010	12,000	40,000	U.S. Gulf
Discoverer Deep Seas (b) (c) (d)	HSD	2001	10,000	35,000	U.S. Gulf
Discoverer Enterprise (b) (c) (d)	HSD	1999	10,000	35,000	U.S. Gulf
Discoverer Spirit (b) (c) (d)	HSD	2000	10,000	35,000	U.S. Gulf
GSF C.R. Luigs (b)	HSD	2000	10,000	35,000	U.S. Gulf
GSF Jack Ryan (b)	HSD	2000	10,000	35,000	Nigeria
Deepwater Discovery (b)	HSD	2000	10,000	30,000	Nigeria
Deepwater Frontier (b)	HSD	1999	10,000	30,000	Australia
Deepwater Millennium (b)	HSD	1999	10,000	30,000	Australia
Deepwater Pathfinder (b)	HSD	1998	10,000	30,000	U.S. Gulf
Deepwater Expedition (b)	HSD	1999	8,500	30,000	Saudi Arabia
Cajun Express (b) (f)	HSS	2001	8,500	35,000	Morocco
Deepwater Nautilus (g)	HSS	2000	8,000	30,000	U.S. Gulf
GSF Explorer (b)	HSD	1972/1998	7,800	30,000	India
Discoverer Luanda (b) (c) (d) (e) (h)	HSD	2010	7,500	40,000	Angola
GSF Development Driller I (b) (c)	HSS	2005	7,500	37,500	U.S. Gulf
GSF Development Driller II (b) (c)	HSS	2005	7,500	37,500	U.S. Gulf
Development Driller III (b) (c)	HSS	2009	7,500	37,500	U.S. Gulf
Sedco Energy (b) (f)	HSS	2001	7,500	35,000	Ghana
Sedco Express (b) (f)	HSS	2001	7,500	35,000	Nigeria
Deepwater Floaters (12)					
Deepwater Navigator (b)	HSD	1971/2000	7,200	25,000	Brazil
Discoverer Seven Seas (b)	HSD	1976/1997	7,000	25,000	Indonesia
Transocean Marianas (g)	HSS	1979/1998	7,000	30,000	Idle
Sedco 702 (b)	HSS	1973/2007	6,500	25,000	Nigeria
Sedco 706 (b)	HSS	1976/2008	6,500	25,000	Brazil
Sedco 707 (b)	HSS	1976/1997	6,500	25,000	Brazil
GSF Celtic Sea (g)	HSS	1982/1998	5,750	25,000	Angola
Jack Bates (g)	HSS	1986/1997	5,400	30,000	Australia
M.G. Hulme, Jr. (g)	HSS	1983/1996	5,000	25,000	India
Sedco 710 (b)	HSS	1983/2001	4,500	25,000	Stacked
Sovereign Explorer (g)	HSS	1984	4,500	25,000	Stacked

Transocean Rather (g)	HSS	1988	4,500	25,000	Stacked
Harsh Environment Floaters (7)					
Transocean Spitsbergen (b) (c)	HSS	2010	10,000	30,000	Norwegian N. Sea
Transocean Barents (b) (c)	HSS	2009	10,000	30,000	Norwegian N. Sea
Henry Goodrich (g)	HSS	1985/2007	5,000	30,000	Canada
Transocean Leader (g)	HSS	1987/1997	4,500	25,000	Norwegian N. Sea
Paul B, Loyd, Jr.(g)	HSS	1990	2,000	25,000	U.K. N. Sea
Transocean Arctic (g)	HSS	1986	1,650	25,000	Norwegian N. Sea
Polar Pioneer (g)	HSS	1985	1,500	25,000	Norwegian N. Sea

"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) Pledged as collateral for certain debt instruments or credit facilities.
(f) Express-class rig.
(g) Moored floaters.
(h) Owned through our 65 percent interest in Angola Deepwater Drilling Company Limited ("ADDCL") and pledged as collateral for the debt of the joint venture company.

Midwater Floaters (22)

Name	Type	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Location
Sedco 700	OS	1973/1997	3,600	25,000	Stacked
Transocean Amirante	OS	1978/1997	3,500	25,000	Idle
Transocean Legend	OS	1983	3,500	25,000	Australia
GSF Arctic I	OS	1983/1996	3,400	25,000	Stacked
Transocean Driller	OS	1991	3,000	25,000	Brazil
GSF Rig 135	OS	1983	2,800	25,000	Congo
GSF Rig 140	OS	1983	2,800	25,000	India
GSF Aleutian Key	OS	1976/2001	2,300	25,000	Stacked
GSF Arctic III	OS	1984	1,800	25,000	U.K. N. Sea
Sedco 711	OS	1982	1,800	25,000	U.K. N. Sea
Transocean John Shaw	OS	1982	1,800	25,000	U.K. N. Sea
Sedco 712	OS	1983	1,600	25,000	U.K. N. Sea
Sedco 714	OS	1983/1997	1,600	25,000	U.K. N. Sea
Actinia	OS	1982	1,500	25,000	India
GSF Grand Banks	OS	1984	1,500	25,000	Canada
Sedco 601	OS	1983	1,500	25,000	Stacked
Sedneth 701	OS	1972/1993	1,500	25,000	Nigeria
Transocean Prospect	OS	1983/1992	1,500	25,000	U.K. N. Sea
Transocean Searcher	OS	1983/1988	1,500	25,000	Norwegian N. Sea
Transocean Winner	OS	1983	1,500	25,000	Norwegian N. Sea
J. W. McLean	OS	1974/1996	1,250	25,000	Stacked
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 (11)

Year Water Drilling

Name	entered service/ upgraded (a)	depth capacity (in feet)	depth capacity (in feet)	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 I	2003	400	30,000	Indonesia
GSF Constellation II	2004	400	30,000	Gabon
GSF Galaxy I	1991/2001	400	30,000	U.K. N. Sea
GSF Galaxy II	1998	400	30,000	U.K. N. Sea
GSF Galaxy III	1999	400	30,000	U.K. N. Sea
GSF Magellan	1992	350	30,000	Nigeria
GSF Monarch	1986	350	30,000	U.K. N. Sea

(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").

Markets

Our operations are geographically dispersed in oil and gas exploration and development areas throughout the world. Although the cost of moving a rig and the availability of rig-moving vessels may cause the balance between supply and demand to vary between regions, significant variations do not tend to exist long-term because of rig mobility. Consequently, we operate in a single, global offshore drilling market. Because our drilling rigs are mobile assets and are able to be moved according to prevailing market conditions, we cannot predict the percentage of our revenues that will be derived from particular geographic or political areas in future periods.

As of February 18, 2014, the fleet associated with our continuing operations was located in the U.S. Gulf of Mexico (14 units), the U.K. North Sea (13 units), Far East (seven units), Norway (seven units), Brazil (six units), India (six units), African countries other than Nigeria and Angola (six units), Nigeria (six units), Angola (four units), Australia (four units), Mediterranean (three units), Canada (two units), and the Middle East (one unit).

In recent years, oil companies have placed increased emphasis on exploring for hydrocarbons in deeper waters. This deepwater focus is due, in part, to technological developments that have made such exploration more feasible and cost-effective. Therefore, water-depth capability is a key component in determining rig suitability for a particular drilling project. Another distinguishing feature in some drilling market sectors is a rig’s ability to operate in harsh environments, including extreme marine and climatic conditions and temperatures.

We categorize the market sectors in which we operate as follows: (1) deepwater, (2) midwater and (3) jackup. The deepwater and midwater market sectors are serviced by our drillships and semisubmersibles. Although the term deepwater, as used in the drilling industry to denote a particular market sector, can vary and continues to evolve with technological improvements, we generally view the deepwater market sector as that which begins in water depths of approximately 4,500 feet and extends to the maximum water depths in which rigs are capable of drilling, which is currently approximately 12,000 feet. We view the midwater market sector as that which covers water depths of about 300 feet to approximately 4,500 feet.

The jackup market sector begins at the outer limit of the transition zone, which is characterized by marshes, rivers, lakes and shallow bay and coastal water areas, and extends to water depths of about 400 feet. This sector has been developed to a significantly greater degree than the deepwater market sector because the shallower water depths have made it much more affordable and accessible than the deeper water market sectors.

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,		
	2013	2012	2011
Operating revenues			
U.S.	$ 2,382	$ 2,472	$ 1,971
Norway	1,208	1,174	897
U.K.	1,181	1,028	1,099
Brazil	855	1,114	1,019
Other countries (a)	3,858	3,408	3,041
Total operating revenues	$ 9,484	$ 9,196	$ 8,027

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

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

	December 31, 2013	December 31, 2012
Long-lived assets		
U.S.	$ 6,996	$ 7,395
Norway	2,091	2,072
Brazil	1,388	2,285
Other countries (a)	11,232	9,128
Total long-lived assets	$ 21,707	$ 20,880

(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, 2013, the contract backlog associated with our continuing operations was approximately $28.2 billion, representing a decrease of 4.1 percent and an increase of 34.9 percent compared to the contract backlog associated with our continuing operations at December 31, 2012 and 2011, which was $29.4 billion and $20.9 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—Performance and Other Key Indicators."

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, 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 sustained periods of 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, the operator indemnifies 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. In connection with the Macondo well incident, a court refused to enforce an indemnity in respect of punitive damages and certain penalties under the Clean Water Act (“CWA”). 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. The inability or other failure of our customers to fulfill their indemnification obligations to us could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. See “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies—Macondo well incident contingencies—Contractual indemnity.”

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, 2013, our most significant customers were Chevron Corporation (together with its affiliates, "Chevron") and BP plc. (together with its affiliates, "BP"), representing approximately 12 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. No other customers accounted for 10 percent or more of our consolidated operating revenues from continuing operations in the year ended December 31, 2013. Additionally, as of February 18, 2014, the customers with the most significant aggregate amount of contract backlog associated with our drilling contracts were Royal Dutch Shell plc and Chevron, representing approximately 35 percent and 19 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, 2013, we had approximately 15,100 employees associated with our continuing operations, including approximately 1,000 persons engaged through contract labor providers. Of our 15,100 employees, approximately 800 persons were working under operating agreements with Shelf Drilling and are expected to transition upon expiration of such operating agreements. Some of our employees working in Angola, the U.K., Nigeria, Norway, Australia and Brazil are represented by, and some of our contracted labor work under, collective bargaining agreements. Many of these represented individuals are working under agreements that 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

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 an 87.5 percent interest in Indigo Drilling Limited ("Indigo"), a consolidated Nigerian joint venture company formed to engage in drilling operations offshore Nigeria. Our local partner, Mr. Chima Ibeneche, holds the remaining 12.5 percent 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.

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. Fifteen rigs in our existing fleet are, and seven 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, 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 system, or to acquire technology through strategic acquisitions.

Environmental Regulation

Our operations are subject to a variety of global environmental regulations. We monitor 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, specifically in 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 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 Corporate Governance section of our website at www.deepwater.com.

Item 1A. Risk Factors

Risks related to our business

The Macondo well incident could result in increased expenses and decreased revenues, which could ultimately have a material adverse effect on us.

Numerous lawsuits have been filed against us and unaffiliated defendants related to the Macondo well incident. We are subject to claims alleging that we are jointly and severally liable, along with BP and others, for damages arising from the Macondo well incident. We have incurred and expect to continue to incur significant legal fees and costs in responding to these matters. In January 2013, we agreed with the U.S. Department of Justice ("DOJ") to pay $1.4 billion in fines, recoveries and penalties, excluding interest, over a five-year period through 2017, and we may be subject to additional governmental fines or penalties. These payments are not deductible for tax purposes. Although we have excess liability insurance coverage relating to certain other liabilities associated with the Macondo well incident, our personal injury and other third-party liability insurance coverage is subject to deductibles and overall aggregate policy limits and does not cover criminal fines and penalties. There can be no assurance that our insurance will ultimately be adequate to cover all of our remaining potential liabilities in connection with these matters. For a discussion of the potential impact of the failure of the Macondo well operator to honor its indemnification obligations to us, see "Item 1A. Risk Factors—Risks related to our business—We could experience a material adverse effect on our consolidated statement of financial position, results of operations or cash flows to the extent any of the Macondo well operator's indemnification obligations to us are not enforceable or the operator does not indemnify us" below. If we ultimately incur substantial additional liabilities in connection with these matters with respect to which we are neither insured nor indemnified, those liabilities could have a material adverse effect on us.

We are currently unable to estimate the full impact the Macondo well incident will have on us. We have recognized a liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made. At December 31, 2013, our liability for such loss contingencies was $464 million. This liability takes into account certain events related to the litigation and investigations arising out of the incident. There are loss contingencies related to the Macondo well incident that we believe are reasonably possible and for which we do not believe a reasonable estimate can be made. These loss contingencies could increase the liabilities we ultimately recognize. Our estimates involve a significant amount of judgment. As a result of new information or future developments, we may adjust our estimated loss contingencies arising out of the Macondo well incident, and the resulting liabilities could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Our business may also be adversely impacted by any negative publicity relating to the incident and us, any negative perceptions about us by customers, the skilled personnel whom we require to support our operations or others, any further increases in premiums for insurance or difficulty in obtaining coverage and the diversion of management's attention from our operations to focus on matters relating to the incident. In addition, the Macondo well incident could negatively impact our ongoing business relationship with BP, which accounted for approximately 10 percent of our consolidated operating revenues from continuing operations in the year ended December 31, 2013. Ultimately, these factors could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

We could experience a material adverse effect on our consolidated statement of financial position, results of operations or cash flows to the extent any of the Macondo well operator's indemnification obligations to us are not enforceable or the operator does not indemnify us.

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. The operator has stated in its public filings that it has recognized cumulative pre-tax losses of $42.7 billion in relation to the spill as of February 4, 2014. As described under "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies—Macondo well incident contingencies—Contractual indemnity," under the Deepwater Horizon drilling contract, BP agreed to indemnify us with respect to certain matters, and we agreed to indemnify BP with respect to certain matters. 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 does not honor its indemnification obligations, including by reason of financial or legal restrictions, or our insurance policies do not fully cover these amounts. In April 2011, BP filed a claim seeking a declaration that it is not liable to us in contribution, indemnification, or otherwise, and further, BP has brought claims against us seeking indemnification and contribution. On November 1, 2011, we filed a motion for partial summary judgment regarding the scope and enforceability of the indemnity obligations in the drilling contract. On January 26, 2012, the court ruled that the drilling contract requires BP to indemnify us for compensatory damages asserted by third parties against us related to pollution that did not originate on or above the surface of the water, even if the claim is the result of our strict liability, negligence or gross negligence. The court also held that BP does not owe us indemnity to the extent that we are held liable for punitive damages or civil penalties under the CWA. The court deferred ruling on BP's argument that we committed a core breach of the drilling contract or otherwise materially increased BP's risk or prejudiced its rights so as to impair BP's indemnity obligations. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy. In May 2013, we filed a motion for partial summary judgment seeking to enforce BP's agreement to release claims made by BP itself. The U.S. District Court, Eastern District of Louisiana (the "MDL Court") has not yet ruled on this motion.

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.

Despite our settlement with the DOJ, we could have additional liabilities to the U.S. government and others. The ultimate outcome of investigations of the Macondo well incident, DOJ lawsuits and our settlement with the DOJ is uncertain.

On December 15, 2010, the DOJ filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleged claims under the Oil Pollution Act of 1990 (the "OPA") and the CWA, including claims for per barrel civil penalties. The complaint asserted that all defendants are jointly and severally liable for all removal costs and damages resulting from the Macondo well incident. On December 6, 2011, the DOJ filed a motion for partial summary judgment seeking a ruling that we were jointly and severally liable under OPA, and liable for civil penalties under the CWA, for all discharges from the Macondo well on the theory that the discharges not only came from the well, but also came from the blowout preventer and riser, appurtenances of Deepwater Horizon. On February 22, 2012, the U.S. District Court, Eastern District of Louisiana, ruled that we are not liable as a responsible party for damages under OPA with respect to the below surface discharges from the Macondo well. The court also ruled that the below surface discharge was discharged from the well facility, and not from the Deepwater Horizon vessel, within the meaning of the CWA, and that we therefore are not liable for such discharges as an owner of the vessel under the CWA. This ruling is currently being appealed to the Fifth Circuit Court of Appeals. In addition, the court ruled that the issue of whether we could be held liable for such discharge under the CWA as an "operator" of the well facility could not be resolved on summary judgment. The court did not determine whether we could be liable for removal costs under OPA, or the extent of such removal costs.

The DOJ also conducted a criminal investigation into the Macondo well incident. On March 7, 2011, the DOJ announced the formation of a task force to investigate possible violations by us and certain unaffiliated parties of the CWA, the Migratory Bird Treaty Act, the Refuse Act, the Endangered Species Act, and the Seaman's Manslaughter Act, among other federal statutes, and possible criminal liabilities, including fines under those statutes and under the Alternative Fines Act. On January 3, 2013, we reached an agreement with the DOJ to resolve certain outstanding civil and potential criminal charges against us arising from the Macondo well incident through a cooperation guilty plea agreement by and among the DOJ and certain of our affiliates (the "Plea Agreement") and the Consent Decree. Our settlement with the DOJ did not release us from liabilities to the U.S. government as to all Macondo-related matters nor did it release all Transocean-related persons and entities. In particular, this agreement was without prejudice to the rights of the U.S. with respect to all other matters, including certain liabilities under the OPA for removal costs or for damages for injury to, loss of or loss of use of natural resources, including the reasonable cost of assessing the damage, certain claims for a declaratory judgment of liability under OPA already claimed by the U.S., and certain liabilities for response costs and damages including injury to park system resources, damages for injury to or loss of natural resources and for the cost of any natural resource damage assessments. We have incurred and will continue to incur costs and have been and will continue to be required to devote management and other corporate resources to comply with our agreements with the U.S. Under these agreements, we are subject to restrictions and obligations not imposed on other drilling contractors, which may adversely impact us. Our failure to comply with the terms of these agreements could also result in additional sanctions and penalties that could adversely affect us.

See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies—Macondo well incident contingencies—Litigation."

Pursuant to our Plea Agreement, we are subject to probation, through February 2018. Pursuant to the terms of our Consent Decree, we are subject to the restrictions of that decree for an extended period of time that will be at least through 2017. Any failure to comply with the Consent Decree or probation could result in additional penalties, sanctions and costs and could adversely affect us. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies—Macondo well incide contingencies—Litigation."

In addition, a number of other governmental and regulatory bodies as well as we and other companies have conducted investigations into the Macondo well incident. Many of these investigations have resulted in reports that are critical of us and our actions leading up to and in connection with the incident.

See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies—Macondo well incident contingencies—Litigation."

We cannot predict the ultimate outcome of the remaining DOJ or other governmental claims or any of the investigations, including any impact on the litigation related to the Macondo well incident, the extent to which we could be subject to fines, sanctions or other penalties or the potential impact of implementing measures resulting from the settlement with the DOJ, our guilty plea or arising from the investigations or the costs to be incurred in completing the investigations.

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, including affiliates of BP. 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 15—Commitments and Contingencies—Macondo well incident settlement obligations—EPA Agreement."

The continuing effects of the enhanced regulations enacted following the Macondo well incident 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 relating 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 U.S. and non-U.S. offshore areas.

Other governments could take similar actions relating 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 all industry participants and may add 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 revenue and profitability. We are unable to predict the full impact that the continuing effects of the enhanced regulations will have on our operations.

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;

- advances in exploration, development and production technology;
- 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;
- the development of new technology to exploit oil and gas reserves, such as shale oil;
- accidents, adverse weather conditions; natural disasters and other similar incidents relating to the oil and gas industry; and
- the worldwide military and political environment, including uncertainty or instability resulting from an escalation or outbreak of armed hostilities, civil unrest or other crises in the Middle East or other geographic areas or acts of terrorism.

Demand for our services is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, oil and natural gas companies, including national oil companies. Any prolonged reduction in oil and natural gas prices could depress the immediate levels of exploration, development and production activity. Perceptions of longer-term lower oil and natural gas prices by oil and gas companies could similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Lower levels of activity result in a corresponding decline in the demand for our services, which could have a material adverse effect on our revenue and profitability. Oil and gas prices and market expectations of potential changes in these prices significantly affect this level of activity. However, higher 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. Also, increased competition for customers' drilling budgets could come from, among other areas, land-based energy markets in Africa, Russia, China, Western Asian countries, the Middle East, the U.S. and elsewhere. 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.

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 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. Intense price competition is often the primary factor in determining which qualified contractor is awarded a job, although rig availability and the quality and technical capability of services and equipment are also considered.

The offshore drilling industry has historically been cyclical and is impacted by oil and gas price levels and volatility. There have been periods of high demand, short rig supply and high dayrates, followed by periods of low 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 increased the supply of rigs by ordering the construction of new units. This 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 that are capable of competing with our rigs that have entered the global market, and there are more that are under contract for construction. The entry into service of these new units has increased and will continue to increase supply and could curtail a strengthening, or trigger a reduction, in dayrates as rigs are absorbed into the active fleet or lead to accelerated stacking of the existing fleet.

A significant number of the newbuild units, including our two Ultra-Deepwater drillships and our five High-Specification Jackups currently under construction, have not been contracted for work, which may intensify price competition. Any further increase in construction of new units would likely exacerbate the negative impact on dayrates and utilization rates. Lower dayrates and rig utilization rates could adversely affect our revenues and profitability.

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

At December 31, 2013 and 2012, our overall debt level was approximately $10.7 billion and $12.5 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 not be able to obtain financing in the future for working capital, capital expenditures, acquisitions, debt service requirements, distributions, share repurchases, or other purposes;

§ we may not be able 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 not be able 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.

Credit rating agencies may lower our corporate credit ratings below investment grade.

Credit rating agencies may downgrade our credit ratings to non-investment grade levels. Such ratings levels could have material adverse consequences on our business and future prospects, including the following:

§ 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 agreements governing certain of our senior notes;

§ cause additional indebtedness of approximately $30 million to become due;

§ 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.

Since the Macondo well incident, Moody’s Investors Service, Standard & Poor’s and Fitch have each downgraded their ratings of our senior unsecured debt on more than one occasion. Any further downgrade by any of the rating agencies could have the effects described above. We cannot provide assurance that our credit ratings will not be downgraded to a non-investment grade rating in the near future. See “Item 1A. Risk Factors—Risks related to our business—The Macondo well incident could result in increased expenses and decreased revenues, which could ultimately have a material adverse effect on us.”

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, 2013, our most significant customers were Chevron and BP, accounting for approximately 12 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. As of February 18, 2014, the customers with the most significant aggregate amount of contract backlog associated with our drilling contracts were Royal Dutch Shell plc and Chevron, representing approximately 35 percent and 19 percent, respectively, of our total contract backlog.

Our relationship with BP, whose affiliate was the operator of the Macondo well, has been and could continue to be negatively impacted by the Macondo well incident. In addition, 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 the U.S., including affiliates of BP. 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, 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.

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 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 typically will not reduce the staff on those rigs because we will 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 expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment, and these expenses could increase for short or extended periods as a result of regulatory or customer requirements that raise maintenance standards above historical levels. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

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

As of February 18, 2014, we had seven 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:

§ availability of suppliers to recertify equipment for enhanced regulations;

§ 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;

§ 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 may not be able to renew or obtain new and favorable 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 in 2014 and 2015. Also, of the units we currently have under construction as part of our newbuild program, five of the 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 current contracts and subsequent contracts. In particular, if oil and natural gas prices are low, 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.

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 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. See "—The Macondo well incident could result in increased expenses and decreased revenues, which could ultimately have a material adverse effect on us."

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. 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.

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 18, 2014, the contract backlog associated with our continuing operations was approximately $27.2 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 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.

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.

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, and taxation 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. For example, our internal compliance program has identified and we have self-reported a potential OFAC compliance issue involving the shipment of goods by a freight forwarder through Iran, a country that has been designated as a state sponsor 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 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, but not limited to, blowouts, reservoir damage, loss of production, loss of well control, punch-throughs, 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, including 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 willing to indemnify us against such risks. In addition, a court may decide that certain indemnities in our current or future drilling contracts are not enforceable. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy, and the enforceability of an indemnity as to other matters may be limited.

Our insurance policies and drilling contracts contain rights to indemnity that may not adequately cover our losses, and we do not have insurance coverage or rights to indemnity for all risks. We have two main types of insurance coverage: (1) hull and machinery coverage for physical damage to our property and equipment and (2) excess liability coverage, which generally covers offshore risks, such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. We generally have no hull and machinery insurance coverage for damages caused by named storms in the U.S. Gulf of Mexico. We maintain per occurrence deductibles on our rigs 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 $870 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 an enforceable or recoverable indemnity from a customer or from Shelf Drilling with respect to (i) the remaining seven standard jackups that we operate as of February 18, 2014, under operating agreements with Shelf Drilling or (ii) the three standard jackups that Shelf Drilling will operate, for which we have agreed to provide a limited guarantee in favor of Shelf Drilling's customer from the time the drilling contracts are novated through expiration of such drilling contracts, such 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. 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.

Our ongoing organizational efficiency initiative may affect our ability to manage our business and our operational results and could result in the loss of key personnel.

We are currently undertaking an organizational efficiency initiative to improve our cost structure and streamline certain shore-based business functions and processes. The organizational efficiency initiative includes a reduction in our workforce as well as the elimination of certain processes, programs and tasks we do not consider to be central to supporting our core business. As we make adjustments to our workforce, we may incur additional expenses that delay or limit any benefit of a more efficient workforce structure. Additionally, the implementation of the organizational efficiency initiative may strain or limit our management and our administrative, technical, operational and financial personnel and may not result in the anticipated improvement in our overall cost structure or the streamlining of our shore-based business functions and processes. If we fail to manage the organizational efficiency initiative changes effectively, it could adversely affect our ability to manage our business and operational results and could result in the loss of key personnel.

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, which could lead to higher downtime and more operating incidents, which in turn could decrease revenues and increase costs. If increased competition for qualified personnel were to intensify in the future we may experience increases in costs or limits on operations.

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.

Some of our employees working in Angola, the U.K., Nigeria, Norway, Australia and Brazil, are represented by, and some of our contracted labor work under, collective bargaining agreements. Many of these represented individuals are working under agreements that 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.

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 cause our ability to access the capital markets to 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. 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. In addition, a portion of the credit under our credit facilities is provided by European banking institutions. If economic conditions in Europe preclude or limit financing from these banking institutions, we may not be able to obtain financing from other institutions on terms that are acceptable to us, or at all, even if conditions outside Europe remain favorable for lending. A slowdown in economic activity could reduce worldwide demand for energy and result in an extended period of lower oil and natural gas prices. A decline in oil and natural gas prices could reduce demand for our drilling services and have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

The world economy and, in particular, the European economy are currently facing a number of challenges. As result of the credit crisis in Europe, concerns persist regarding the debt burden of certain Eurozone countries and their ability to meet future financial obligations and the overall stability of the euro. An extended period of adverse development in the outlook for European countries 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 adverse development in the outlook for the world economy could 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.

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 (the "FCPA"), the U.K. Bribery Act 2010 (the "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 or the Bribery Act, either due to our own acts or our 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.

Civil penalties under the anti-bribery provisions of the FCPA could range up to $10,000 per violation, with a criminal fine up to the greater of $2 million per violation or twice the gross pecuniary gain to us or twice the gross pecuniary loss to others, if larger. Civil penalties under the accounting provisions of the FCPA can range up to $500,000 per violation and a company that knowingly commits a violation can be fined up to $25 million per violation. In addition, both the SEC and the DOJ could assert that conduct extending over a period of time may constitute multiple violations for purposes of assessing the penalty amounts. Often, dispositions for these types of matters result in modifications to business practices and compliance programs and possibly the appointment of a monitor to review future business and practices with the goal of ensuring compliance with the FCPA.

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. Our customers in those jurisdictions could seek to impose penalties or take other actions adverse to our interests. We could also face other third-party claims by agents, shareholders, debt holders, or other interest holders or constituents of our company. In addition, disclosure of the subject matter of the investigation could adversely affect our reputation and our ability to obtain new business or retain existing business from our current customers and potential customers, to attract and retain employees and to access the capital markets.

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 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, are attracting increasing attention worldwide.

Legislation to regulate emissions of GHGs has been introduced in the U.S. Congress, and there has been a wide-ranging policy debate, both in the U.S. and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries to meet stringent new standards that would require substantial reductions in carbon emissions. Those 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, such as the United Nations Climate Change Conference in Doha in 2012. Also, the EPA has undertaken efforts to collect information regarding GHG emissions and their effects. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA finalized motor vehicle GHG standards, the effect of which could reduce demand for motor fuels refined from crude oil, and 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 the motor vehicle standards took effect on January 2, 2011. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year are now required to report annual GHG emissions to the EPA.

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.

In addition to the litigation surrounding the Macondo well incident, we are subject to a variety of other 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, and 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 criminal and civil charges that commenced in Norway in late 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.

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

Public health threats, such as the H1N1 flu virus, Severe Acute Respiratory Syndrome, and other highly communicable 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. Any 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.

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 social unrest could affect the markets for drilling services.

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 coverages may be unavailable 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 social unrest. We have limited insurance for our assets providing coverage for physical damage losses resulting from risks, such as terrorist acts, piracy, civil unrest, expropriation and acts of war, and we do not carry insurance for loss of revenues resulting from such risks. Government regulations may effectively preclude us from actively 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.

Other risks

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 or policies, or their interpretation, 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. In November 2013, the Senate Finance Committee introduced an international tax reform discussion draft, which proposed a number of international tax changes, including a proposal which could limit the deduction for intercompany payments in certain circumstances. 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 Organisation for Economic Co-operation and Development. 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. The U.K.’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.

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.

The Norwegian authorities have issued criminal indictments against two of our subsidiaries alleging misleading or incomplete disclosures in Norwegian tax returns for the years of 1999 through 2002, as well as civil actions based upon inaccuracies in Norwegian statutory financial statements for the periods of 1996 through 2001. These trials have been completed, and we are awaiting decisions from the courts. We cannot be certain of the outcome of either the civil or criminal trials. An unfavorable outcome on the Norwegian civil or criminal tax matters could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

U.S. tax authorities could treat us as a "passive foreign investment company", which could 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 recent case and an IRS pronouncement which relies on the recent 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 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 have significant carrying amounts of long-lived assets and goodwill that are subject to impairment testing.

At December 31, 2013, the carrying amount of our property and equipment was $21.7 billion, representing 67 percent of our total assets, and the carrying amount of our goodwill was $3.0 billion, representing nine 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, and we conduct impairment testing for our goodwill annually and when events and circumstances indicate that the fair value of a reporting unit may have fallen below its carrying amount.

In the year ended December 31, 2012, in connection with the sale of 38 drilling units to Shelf Drilling, we recognized losses of $744 million and $112 million on the impairment of long-lived assets and goodwill, respectively, attributable to the transactions. As a result of our goodwill impairment test, performed as of October 1, 2011, we recognized an aggregate loss of $5.3 billion associated with the impairment of goodwill attributed to our contract drilling services reporting unit due to a decline in projected cash flows and market valuations for this reporting unit. 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, particularly with respect to our High-Specification Jackups and Midwater Floaters, or our goodwill 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 or goodwill may be impaired.

We have significant exposure to losses resulting from our contractual relationships with Shelf Drilling and its affiliates.

In connection with our sale transactions with Shelf Drilling, we agreed to indemnify Shelf Drilling from certain liabilities, and Shelf Drilling agreed to indemnify us from certain liabilities and make certain payments to us. However, the indemnity from Shelf Drilling may not be sufficient to protect us against the full amount of liabilities to third parties, and Shelf Drilling may not be willing or able to satisfy its indemnification or payment obligations in the future.

Pursuant to the agreements we entered into with Shelf Drilling, including purchase agreements, operating agreements with respect to rigs that we continue to operate on behalf of Shelf Drilling and a transition services agreement, we agreed to indemnify Shelf Drilling from certain liabilities, and Shelf Drilling agreed to indemnify us from certain liabilities, including, without limitation, liabilities related to operational risks with respect to Shelf Drilling's rigs, liabilities related to credit support we are providing to Shelf Drilling and certain liabilities related to employees, and to make certain payments to us. However, third parties could seek to hold us responsible for the liabilities with respect to which Shelf Drilling has agreed to indemnify us, including, but not limited to, any obligations arising from the three standard jackups that Shelf Drilling operates, for which we have agreed to provide a limited guarantee in favor of Shelf Drilling’s customer from the time the drilling contracts are novated through expiration of such drilling contracts. In addition, the indemnity may not be sufficient to protect us against the full amount of such liabilities, and Shelf Drilling may not be willing or able to satisfy its indemnification or payment obligations to us. Moreover, even if we ultimately succeed in recovering from Shelf Drilling any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves. Each of these risks could adversely affect our business or our consolidated statement of financial position, results of operations or cash flows.

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. 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 2013 annual general meeting, our shareholders did not renew our authorized share capital, which expired on May 13, 2013. Unless our shareholders approve the new authorized share capital proposed by our board of directors at our 2014 annual general meeting, which would be limited to approximately six percent of our registered share capital, 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 a further three-year repurchase period through May 23, 2016. We may repurchase shares under the share repurchase program via a second trading line on the SIX from institutional investors who are generally able to receive a full refund of the Swiss withholding tax. Alternatively, in relation to the U.S. market, we may repurchase shares under the share repurchase program using an alternative 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. There may not be sufficient liquidity in our shares on the SIX to repurchase the amount of shares that we would like to repurchase using the second trading line on the SIX. In addition, 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 either the "virtual second trading line" or, in the future, a SIX second trading line without subjecting the selling shareholders to Swiss withholding taxes.

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 for a conditional share capital that authorizes the issuance of additional shares up to a maximum amount of 50 percent of the share capital 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.

In addition, our board of directors has proposed for approval by the shareholders at the 2014 annual general meeting the adoption of authorized share capital. Subject to obtaining shareholder approval, the proposed authorized share capital would give our board of directors the authority to issue at any time during a two-year period extending until May 16, 2016, up to approximately six percent of the share capital currently registered in the commercial register, and to limit or withdraw the preemptive rights of existing shareholders in various circumstances.

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 15—Commitments and Contingencies” and “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident” in this annual report on Form 10-K for the year ended December 31, 2013. 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 Discussi and Analysis of Financial Condition and Results of Operations—Contingencies—Tax matters” in this annual report on Form 10-K for the year ended December 31, 2013. All such actions, claims, tax and other matters are incorporated herein by reference.

As of December 31, 2013, we were also involved in a number of other lawsuits and other matters which have arisen in the ordinary course of our business and for which we do not expect the liability, if any, resulting from these lawsuits 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 other matters will prove correct and the eventual outcome of these matters could materially differ from management’s current estimates.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

We have included the following information, presented as of February 18, 2014, 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 18, 2014
Steven L. Newman (a)	President and Chief Executive Officer	49
Esa Ikäheimonen (a)	Executive Vice President, Chief Financial Officer	50
Allen M. Katz	Interim Senior Vice President and General Counsel	65
Lars Sjöbring	Senior Vice President and General Counsel	46
John B. Stobart (a)	Executive Vice President, Chief Operating Officer	59
David Tonnel	Senior Vice President, Finance and Controller	44

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

Steven L. Newman is President and Chief Executive Officer and a member of the board of directors of the Company. Before being named as Chief Executive Officer in March 2010, Mr. Newman served as President and Chief Operating Officer from May 2008 to November 2009 and subsequently as President. Mr. Newman's prior senior management roles included Executive Vice President, Performance from November 2007 to May 2008, Executive Vice President and Chief Operating Officer from October 2006 to November 2007, Senior Vice President of Human Resources and Information Process Solutions from May 2006 to October 2006, Senior Vice President of Human Resources, Information Process Solutions and Treasury from March 2005 to May 2006, and Vice President of Performance and Technology from August 2003 to March 2005. He also has served as Regional Manager for the Asia and Australia Region and in international field and operations management positions, including Project Engineer, Rig Manager, Division Manager, Region Marketing Manager and Region Operations Manager. Mr. Newman joined the Company in 1994 in the Corporate Planning Department. Mr. Newman received his Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1989 and received his Master of Business Administration from the Harvard University Graduate School of Business in 1992. Mr. Newman is also a member of the Society of Petroleum Engineers and the National Association of Corporate Directors.

Esa Ikäheimonen is Executive Vice President, Chief Financial Officer of the Company. Before being named Executive Vice President, Chief Financial Officer in November 2012, Mr. Ikäheimonen served as a consultant to the Company from September 2012 to November 2012. He has served as a non-executive director and the chairman of the audit committee of Ahlstrom Corporation since April 2011. Mr. Ikäheimonen served as Senior Vice President and Chief Financial Officer of Seadrill Ltd. from August 2010 to September 2012, and he served as Executive Vice President and Chief Financial Officer of Poyry plc from March 2009 to July 2010. At Royal Dutch Shell, Mr. Ikäheimonen served as Vice President Finance, Shell Africa E&P from June 2007 to March 2009, as Vice President Finance, Shell Upstream Middle East from January 2007 to June 2007, and as Finance and Commercial Director, Shell Qatar from May 2004 to January 2007. Prior to May 2004, Mr. Ikäheimonen served in various financial roles for Royal Dutch Shell, including Strategy and Portfolio Manager, Shell Europe Oil Products, Finance Director, Shell Scandinavia, and Finance Director, Shell Finland. Mr. Ikäheimonen received his Master of Laws degree from the University of Turku in Finland in 1989.

Allen M. Katz is Interim Senior Vice President and General Counsel of the Company and is expected to serve in his current position through February 28, 2014. Before joining the Company in November 2012, he served as an advisor to the Company from June 2010 to November 2012, in his capacity as an attorney at Munger, Tolles & Olson, LLP. Mr. Katz was in retirement from May 1996 to June 2010. He practiced as a partner with Munger, Tolles & Olson, LLP from 1974 to 1996, and served as Managing Partner of the firm from 1991 to 1995. Mr. Katz received his Bachelor of Arts in History from Brandeis University in Massachusetts in 1969 and received his Juris Doctorate from Stanford Law School in 1972. Mr. Katz is a member of the California, 5th and 9th Circuit bars and is admitted to practice before the U.S. Supreme Court.

Effective March 1, 2014, Lars Sjöbring has been named Senior Vice President and General Counsel of the Company. Before being named to this position, Mr. Sjöbring served as the Vice President Legal Affairs, General Counsel and Secretary of Autoliv, Inc. from September 2007 to February 2014. Mr. Sjöbring served as Senior Legal Counsel and, subsequently, as Director, Legal, Mergers and Acquisitions for Nokia Corporation from September 2003 to September 2007. He also served as Foreign Legal Counsel for Skadden, Arps, Slate, Meagher & Flom LLP from September 2000 to June 2003. Mr. Sjöbring received his Master of Laws degrees from Lund University in Sweden in 1994 and from University of Amsterdam in Netherlands in 1995, and he received a Master of Corporate Law degree from Fordham University School of Law in New York in 2003.

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 received his Bachelor of Science in Mechanical Engineering from the University of Calgary in 1980 and completed the London Business School Accelerated Development Program in 2000.

David Tonnel is Senior Vice President, Finance and Controller of the Company. Before being named to his current position in March 2012, Mr. Tonnel served 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 received his Master of Science in Management from Ecole des Hautes Etudes Commerciales in Paris, France in 1991.

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 symbol "RIG" and on the SIX Swiss Exchange ("SIX") under the symbol "RIGN." The following table presents the high and low sales prices of our shares as reported on the NYSE and the SIX for the periods indicated.

	NYSE Stock Price				SIX Stock Price			
	2013		2012		2013		2012	
	High	Low	High	Low	High	Low	High	Low
First quarter	$ 59.50	$ 45.23	$ 59.03	$ 38.80	CHF 54.70	CHF 42.12	CHF 54.30	CHF 36.70
Second quarter	55.79	46.02	56.36	39.32	54.25	43.09	50.80	37.92
Third quarter	50.45	44.32	50.38	43.04	48.00	40.09	49.06	41.55
Fourth quarter	55.74	44.19	49.50	43.65	51.25	40.12	46.62	40.18

On February 18, 2014, the last reported sales price of our shares on the NYSE and the SIX was $43.00 per share and CHF 37.71 per share, respectively. On such date, there were 7,346 holders of record of our shares and 361,024,286 shares outstanding.

Shareholder Matters

Shareholder distributions

In November 2013, under the terms of an agreement with Carl Icahn and certain investment funds managed by Mr. Icahn (the "Icahn Group"), our board of directors agreed to recommend that shareholders at the May 2014 annual general meeting approve a distribution of qualifying additional paid-in capital in the form of a United States ("U.S.") dollar denominated dividend of $3.00 per outstanding share, payable in four installments. The recommendation will be subject to shareholder approval at our 2014 annual general meeting and subject to certain limitations. Further, our board of directors agreed to propose at the 2014 annual general meeting (1) Samuel Merksamer for reelection, and Vincent Intrieri and, subject to certain conditions, a third Icahn Group nominee for election, as directors, and (2) a reduction in the maximum number of directors on the board of directors provided for in our articles of association from 14 to 11.

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 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. At February 18, 2014, the carrying amount of the unpaid distribution payable was $202 million.

In May 2011, at our annual general meeting, our shareholders approved the distribution of additional paid-in capital in the form of a U.S. dollar denominated dividend of $3.16 per outstanding share, payable in four installments of $0.79 per outstanding share, subject to certain limitations. On June 15, September 21 and December 21, 2011 we paid the first three installments, in the aggregate amount of $759 million, to shareholders of record as of May 20, August 26 and November 25, 2011, respectively. On March 21, 2012, we paid the final installment in the aggregate amount of $276 million to shareholders of record as of February 24, 2012.

Any future declaration and payment of any cash distributions will (1) depend on our results of operations, financial condition, cash requirements and other relevant factors, (2) be subject to shareholder approval, (3) be subject to restrictions contained in our credit facilities and other debt covenants, (4) be affected by our plans regarding share repurchases or noncash shareholder distributions and (5) be subject to restrictions imposed by Swiss law, including the requirement that sufficient distributable profits from the previous year or freely distributable reserves must exist.

Swiss tax consequences to our shareholders

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

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

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

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

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

Exemption—Distributions to shareholders in 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, 2013, the aggregate amount of par value of our outstanding shares was CHF 5.6 billion, equivalent to $6.3 billion, and the aggregate amount of qualifying additional paid-in capital of our outstanding shares was CHF 9.6 billion, equivalent to $10.8 billion, at an exchange rate of $1.00 to CHF 0.89 on December 31, 2013. 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:

§ beneficial ownership,

§ U.S. residency, and

§ 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.

Repurchases of shares

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.

In most instances, Swiss companies listed on the SIX carry out share repurchase programs through a second trading line on the SIX. Swiss institutional investors typically purchase shares from shareholders on the open market and then sell the shares on the second trading line back to the company. The Swiss institutional investors are generally able to receive a full refund of the withholding tax. Due to, among other things, the time delay between the sale to the company and the institutional investors' receipt of the refund, the price companies pay to repurchase their shares has historically been slightly higher (but less than one percent) than the price of such companies' shares in ordinary trading on the SIX first trading line. Because our shares are listed on the SIX, we may repurchase our shares from institutional investors who are generally able to receive a full refund of the Swiss withholding tax via a second trading line on the SIX. There may not be sufficient liquidity in our shares on the SIX to repurchase the amount of shares that we would like to repurchase using the second trading line on the SIX. In relation to the U.S. market, we may therefore repurchase such shares using 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 either the "virtual second trading line" or a SIX 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 2013	8,709	$ 47.07	—	$ 3,682
November 2013	20,756	53.65	—	3,682

December 2013	16,306		49.51	—	3,682
Total	45,771	$	50.92	— $	3,682

(1) Total number of shares purchased in the fourth quarter of 2013 consists of 45,771 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.

(2) 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 $3.9 billion at an exchange rate as of December 31, 2013 of USD 1.00 to CHF 0.89. 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 a further three-year repurchase period through May 23, 2016. We may decide, based upon our ongoing capital requirements, our program of distributions to our shareholders, the price of our shares, matters relating to the Macondo well incident, 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, 2013, 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Sources and Uses of Liquidity—Overview."

Item 6. Selected Financial Data

The selected financial data as of December 31, 2013 and 2012 and for each of the three years in the period ended December 31, 2013 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, 2011, 2010 and 2009, and for each of the two years in the period ended December 31, 2010 have been derived from our accounting records. The following data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements and the notes thereto included under "Item 8. Financial Statements and Supplementary Data."

	Years ended December 31,				
	2013	2012	2011 (a)	2010	2009
	(In millions, except per share data)				
Statement of operations data					
Operating revenues	$ 9,484	$ 9,196	$ 8,027	$ 7,949	$ 8,910
Operating income (loss)	2,224	1,581	(4,762)	2,730	3,525
Income (loss) from continuing operations	1,406	816	(5,762)	1,863	2,426
Net income (loss)	1,407	(211)	(5,677)	969	3,170
Net income (loss) attributable to controlling interest	1,407	(219)	(5,754)	926	3,181
Per share earnings (loss) from continuing operations					
Basic	$ 3.87	$ 2.27	$ (18.14)	$ 5.66	$ 7.56
Diluted	$ 3.87	$ 2.27	$ (18.14)	$ 5.66	$ 7.54
Balance sheet data (at end of period)					
Total assets	$ 32,546	$ 34,255	$ 35,032	$ 36,814	$ 36,436
Debt due within one year	323	1,367	2,187	2,160	1,868
Long-term debt	10,379	11,092	11,349	9,061	9,849
Total equity	16,685	15,730	15,627	21,340	20,559
Other financial data					
Cash provided by operating activities	$ 1,918	$ 2,708	$ 1,825	$ 3,906	$ 5,598
Cash used in investing activities	(1,658)	(389)	(1,896)	(721)	(2,694)
Cash provided by (used in) financing activities	(2,151)	(1,202)	734	(961)	(2,737)
Capital expenditures	2,238	1,303	974	1,349	2,948
Distributions of qualifying additional paid-in capital	606	276	759	—	—

Per share distributions of qualifying additional paid-in capital	$ 1.68	$ 0.79	$ 2.37	$ —	$ —

(a) 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.

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 18, 2014, we owned or had partial ownership interests in and operated 79 mobile offshore drilling units associated with our continuing operations. As of February 18, 2014, our fleet consisted of 46 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 22 Midwater Floaters, and 11 High-Specification Jackups. At February 18, 2014, we also had seven Ultra-Deepwater drillships and five High-Specification Jackups under construction or under contract to be constructed.

Our primary business is contract drilling services, which operates in a single, global segment and 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 build or upgrade rigs are determined by the activities and needs of our customers.

In November 2012, in connection with our efforts to dispose of non-strategic assets and reduce our exposure to low-specification drilling units, we completed the sale of 38 drilling units to Shelf Drilling Holdings, Ltd. ("Shelf Drilling"). For a transition period following the completion of the sale transactions, we agreed to continue to operate a substantial portion of these drilling units on behalf of Shelf Drilling and to provide certain other transition services to Shelf Drilling. As of February 18, 2014, under operating agreements, we continue to operate seven standard jackups on behalf of Shelf Drilling until expiration of the underlying drilling contracts, which is expected in mid-2014. In addition, under a transition services agreement, we continue to provide certain transition services, which we expect to end in mid-2014. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 7—Discontinued Operations."

Significant Events

Distributions of qualifying additional paid-in capital—In November 2013, our board of directors agreed to recommend that shareholders at the May 2014 annual general meeting approve a distribution of qualifying additional paid-in capital in the form of a U.S. dollar denominated dividend of $3.00 per outstanding share, for an aggregate amount of $1.1 billion, payable in four installments, subject to certain limitations. The recommendation will be subject to shareholder approval at our 2014 annual general meeting and certain limitations under Swiss law.

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 installments, subject to certain limitations. 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. In June, September and December 2013, we paid the first three installments in the aggregate amount of $606 million to shareholders as of the respective record dates. See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Organizational efficiency initiative—During the year ended December 31, 2013, we committed to a plan to improve the organizational efficiency of our shore-based support activities worldwide. We believe this organizational efficiency initiative will result in our achieving significant annualized savings associated with the streamlining of certain shore-based business functions and processes and the elimination of certain processes, programs and tasks that we do not consider central to supporting our core business. See "—Outlook—Organizational efficiency initiative."

Macondo well incident—On January 3, 2013, we reached an agreement with the U.S. Department of Justice (the "DOJ") to resolve certain outstanding civil and potential criminal charges against us arising from the Macondo well incident. As part of this resolution, we agreed to pay $1.4 billion in fines, recoveries and penalties, plus interest, in scheduled payments over a five-year period through 2017. See "—Contingencies—Macondo well incident."

Frade field incident—On September 17, 2013, one of our subsidiaries entered into an agreement with Chevron, the Brazilian Federal Prosecutor's Office and certain Brazilian governmental agencies regarding the settlement of the federal civil claims related to the Brazil Frade field incident (the "Frade Settlement Agreement"). The Frade Settlement Agreement releases us from the federal civil claims without a finding of fault or liability. We have no financial obligations under the Frade Settlement Agreement. The Frade Settlement Agreement became binding upon all parties when it was approved by the federal court on September 27, 2013, and as a result, the federal civil claims were dismissed.

Debt repayment—Through our wholly-owned subsidiary, Transocean Pacific Drilling Inc. (“TPDI”), we had three credit facilities, established under a bank credit agreement dated October 28, 2008 (the “TPDI Credit Facilities”). In June 2013, we repaid borrowings of $735 million outstanding under the TPDI Credit Facilities and terminated the bank credit agreement under which they were established.

On March 6, 2013, we redeemed the FRN Aker Drilling ASA Senior Unsecured Callable Bond Issue 2011/2016 (the “FRN Callable Bonds”) and the 11% Aker Drilling ASA Senior Unsecured Callable Bond Issue 2011/2016 (the “11% Callable Bonds,” and together with the FRN Callable Bonds, the “Callable Bonds”), with the aggregate outstanding principal amounts of NOK 940 million and NOK 560 million, equivalent to $164 million and $98 million, respectively, using an exchange rate of NOK 5.73 to $1.00. In connection with the redemption, we made an aggregate cash payment of NOK 1,567 million, equivalent to $273 million.

On February 7, 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.

During the year ended December 31, 2013, we repaid the outstanding $250 million and $500 million aggregate principal amount of the 5% Notes due February 2013 and the 5.25% Senior Notes due March 2013, respectively, as of the stated maturity dates.

Angola Deepwater Drilling Company Limited (“ADDCL”), a consolidated joint venture company, had two credit facilities, established under a bank credit agreement (the “ADDCL Credit Facilities”). On February 12, 2014, we repaid borrowings of $163 million outstanding under the ADDCL Credit Facilities and terminated the bank credit agreement under which the credit facilities were established.

See “—Liquidity and Capital Resources—Sources and uses of liquidity.”

Fleet expansion—During the year ended December 31, 2013, we completed construction of the High-Specification Jackups Transocean Andaman, Transocean Siam Driller and Transocean Ao Thai, which have commenced operations under their contracts.

In October 2013, we were awarded a five-year drilling contract for a newbuild dynamically positioned Ultra-Deepwater drillship, and we entered into a shipyard contract for the construction of the drillship.

In November 2013, we entered into agreements for the construction of five High-Specification Jackups. Additionally, each of the five shipyard contracts includes an option to order an additional jackup of the same design and specifications on similar terms. The first option must be exercised by November 2014, and the remaining four options must be exercised within consecutive four-month intervals thereafter.

On February 26, 2014, we entered into agreements for the construction of two newbuild dynamically positioned Ultra-Deepwater drillships. We also entered into an options agreement to order up to three additional newbuild drillships with the same design and specifications. The first option must be exercised within one year, the second within 18 months and the final within 24 months.

See “—Liquidity and Capital Resources—Drilling fleet.”

Dispositions—During the year ended December 31, 2013, in connection with our efforts to dispose of non-strategic assets, we completed the sale of the Deepwater Floater Transocean Richardson along with related equipment. In connection with the sale of these assets, we received net cash proceeds of $142 million, and recognized an aggregate net gain of $33 million, $22 million, net of tax. In February 2014, we completed the sale of the High-Specification Jackup GSF Monitor along with related equipment. See “—Liquidity and Capital Resources—Drilling fleet.”

Shelf Drilling preference shares—In June 2013, we completed the sale of the Shelf Drilling preference shares. In connection with the sale, we received cash proceeds of $185 million, and recognized a loss of $10 million. See “—Liquidity and Capital Resources—Sources and uses of cash.”

Discontinued operations—In February 2014, in connection with our efforts to discontinue non-strategic operations, we completed the sale of Advanced Drilling Technology International Limited, a U.K. company that performs drilling management services in the North Sea. Following the completion of the sale transaction, we agreed to provide a $15 million working capital line of credit to the buyer for up to two years. We have also provided a limited guarantee in favor of one customer through expiration of the current drilling project, which is expected to be completed in the fourth quarter of 2014. The disposal of this component of our business results in the discontinuation of our drilling management services operating segment in the year ending December 31, 2014.

During the year ended December 31, 2013, we completed the sales 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 connection with the sales of these assets of our discontinued operations, we received aggregate net cash proceeds of $140 million and recognized an aggregate net gain of $44 million.

See “—Operating Results—Discontinued operations.”

Outlook

Drilling market—We expect the commodity pricing underlying the exploration and production programs of our customers to continue to support some contracting opportunities for all asset classes within our drilling fleet in the year ending December 31, 2014. However, based on customer and market indications, we expect the pace of executing drilling contracts for the global floater fleet to slow in the near term, resulting in excess capacity and idle time for some rigs. As of February 18, 2014, the contract backlog for our continuing operations was $27.2 billion compared to $29.8 billion as of October 16, 2013.

Following the Macondo well incident, the U.S. government implemented enhanced regulations related to offshore drilling in the U.S. Gulf of Mexico, which require operators to submit applications for new drilling permits that demonstrate compliance with such enhanced regulations. The enhanced regulations require independent third-party inspection, certification of well design and well control equipment and emergency response plans in the event of a blowout, among other requirements. The voluntary application by some of our customers of such third-party inspections and certifications of well control equipment operating outside the U.S. Gulf of Mexico has caused and may continue to cause us to experience additional out of service time and incur additional maintenance costs. We have entered into an agreement with the DOJ that also requires us to undertake certain inspections and certifications beyond current legal standards. Although the enhanced regulations and additional maintenance requirements have affected our revenues, costs and out of service time, we are unable to predict, with certainty, the magnitude with which these matters will continue to impact our operations.

Fleet status—As of February 18, 2014, uncommitted fleet rates for the years ending December 31, 2014, 2015, 2016, 2017 and 2018 were as follows:

	2014	2015	2016	2017	2018
Uncommitted fleet rate (a)					
High-Specification Floaters	24%	52%	67%	76%	83%
Midwater Floaters	33%	56%	89%	100%	100%
High-Specification Jackups	10%	38%	68%	80%	87%

(a) 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.

As of February 18, 2014, we had 11 existing contracts associated with our continuing operations that had fixed-price or capped options to extend the contract terms that are exercisable, at the customer's discretion, any time through their expiration dates. Customers are more likely to exercise fixed-price options when dayrates are higher on new contracts relative to existing contracts, and customers are less likely to exercise fixed-price options when dayrates are lower on new contracts relative to existing contracts. Given current market conditions, we are uncertain whether these options will be exercised by our customers in 2014. Additionally, well-in-progress or similar provisions of our existing contracts may delay the start of higher or lower dayrates in subsequent contracts, and some of the delays could be significant.

High-Specification Floaters—During the fourth quarter of 2013, seven contracts for Ultra-Deepwater Floaters were entered into worldwide, including three new contracts and one extension to an existing contract for our fleet. Our Ultra-Deepwater Floater fleet has 13 units with availability in 2014. With the expected slowdown of customer demand for the Ultra-Deepwater Fleet in the near term, we expect to see a moderation in utilization and pressure on rates in 2014. The Deepwater Floater fleet rig utilization rate for the industry decreased during the fourth quarter of 2013 with four contracts entered into worldwide. Our Deepwater Floater fleet has six active units with availability in 2014. The pace of tendering and length of contract terms have decreased, and we are experiencing increased competition for each tendering opportunity. As of February 18, 2014, we had 23 of our 46 High-Specification Floaters contracted through the end of 2014. Although we believe continued exploration successes in the major deepwater offshore provinces and the emerging markets will generate additional demand and support our long-term positive outlook for our High-Specification Floater fleet, we expect reduced dayrates and increased competition for our non-harsh environment floaters in the short term.

Midwater Floaters—Customer demand for our Midwater Floater fleet, which includes 22 semisubmersible rigs, has remained stable in the U.K. and Norway. We extended one contract for our Midwater Floater fleet in the fourth quarter of 2013, and we have five units available in our active fleet in 2014. The tendering pace has slowed and expected demand has diminished outside of the U.K. and Norway, notably in Brazil and the Mediterranean, which has had a negative effect on global rig utilization rates and dayrates for this asset class in 2014.

High-Specification Jackups—We believe that market conditions will continue to sustain the high rig utilization rates and increased tendering and contracting activity through 2014. During the fourth quarter, contracting activity increased by 28 percent over the previous quarter with average term extended to 1.3 years per contract. As of February 18, 2014, two of our existing 11 High-Specification Jackups have availability in 2014.

Operating results—We expect our total revenues for the year ending December 31, 2014 to be higher than our total revenues for the year ended December 31, 2013, primarily due to partial years of operating dayrate for our two newbuild Ultra-Deepwater Floaters that are expected to be placed into service during 2014, full years of operating dayrate for our three newbuild High-Specification Jackups placed into service during 2013, fewer expected out of service days for planned shipyards, and increased earned operating dayrates for our contracted fleet, partially offset by a decrease in activity for some of our Ultra-Deepwater Floaters, Deepwater Floaters and Midwater Floaters. We are unable to predict, with certainty, the impact on our business from any changes to offshore activity levels, the results of our efforts to improve our revenue efficiency rates or the full impact that the enhanced regulations and other matters, described under "—Drilling market", will have on our operations for the year ending December 31, 2014 and beyond.

We expect our total operating and maintenance expenses for the year ending December 31, 2014 to be slightly lower relative to our total operating and maintenance expenses for the year ended December 31, 2013, primarily due to a decrease in activity levels for our Midwater Floater fleet and certain Deepwater and Ultra-Deepwater Floaters, optimization of rig-based spending and reductions in shore-based costs, partially offset by increased costs associated with partial years of operation for our newbuild Ultra-Deepwater Floaters, full years of operations for our newbuild High-Specification Jackups, and normal inflationary trends for personnel, maintenance and other operating costs. Our projected operating and maintenance expenses for the year ending December 31, 2014 are subject to change and could be affected by actual activity levels, changes in shipyard timing, rig reactivations, the effective execution of our margin improvement efforts, the enhanced regulations and other matters described under "—Drilling market", the Macondo well incident and related contingencies, exchange rates and cost inflation above expectations, as well as other factors.

Although we are unable to estimate the full direct and indirect effect that the Macondo well incident will have on our business, the incident has had and could continue to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. See "—Contingencies—Macondo well incident."

In accordance with our critical accounting policies, we review our property and equipment for impairment when events occur or circumstances change that may indicate that the carrying amounts of our assets held and used may not be recoverable, and we conduct impairment testing for our goodwill annually and when events occur or circumstances change, such as a significant change in or disposal of a component of our organization, that may indicate a reduction in the fair value of a reporting unit below its carrying amount. If we are unable to secure new or extended contracts for our active units or the reactivation of any of our stacked units, or if we experience unfavorable changes to actual or anticipated dayrates or other impairment indicators, we may be required to recognize losses in future periods as a result of impairments of the carrying amount of one or more of our asset groups. We may also be required to recognize losses on the impairment of one or more of our asset groups as a result of any significant changes in composition of our asset groups. We may be required to recognize losses on impairment of goodwill if we determine that the fair value of our contract drilling services reporting unit has declined below its carrying amount. At December 31, 2013, the carrying amount of our property and equipment, net of accumulated depreciation, was $21.7 billion, representing 67 percent of our total assets. See "—Critical Accounting Policies and Estimates" and "Item 1A. Risk Factors—Other risks—We have significant carrying amounts of long-lived assets and goodwill that are subject to impairment testing."

Master limited partnership formation—We have concluded that a master limited partnership ("MLP")-type yield vehicle could complement our capital structure by providing an additional source of capital, enhancing our financial flexibility. We expect to complete the formation of a MLP-type yield vehicle in mid-2014 and to sell a noncontrolling interest in an initial public offering thereafter. The anticipated offering is subject to market conditions, the approval of our board of directors and the effectiveness of a registration statement to be filed with the U.S. Securities and Exchange Commission ("SEC").

Organizational efficiency initiative—During the year ended December 31, 2013, we began implementing a plan to improve the organizational efficiency of our shore-based support activities worldwide. We believe this organizational efficiency initiative will result in our achieving significant annualized savings associated with the streamlining of certain shore-based business functions and processes and the elimination of certain processes, programs and tasks that we do not consider central to supporting our core business. We have identified and begun eliminating certain shore-based positions within the scope of the initiative. See "Item 1A. Risk Factors—Risks related to our business—Our ongoing organizational efficiency initiative may affect our ability to manage our business and our operational results and could result in the loss of key personnel."

In connection with this initiative, we established certain one-time termination benefit plans for shore-based employees in the U.S., the U.K. and France and for shore-based expatriate resident employees worldwide that were or are expected to be involuntarily terminated during the period from May 2013 through December 31, 2014. In the year ended December 31, 2013, we recognized costs of $32 million associated with severance-related costs under these one-time termination benefit plans.

Additionally, in the year ended December 31, 2013, we recognized costs of $28 million associated with previously established compensatory plans that offer end of service arrangements, the accelerated recognition for share-based compensation costs under our long-term incentive plan, and the termination of executory agreements related to closing certain shore-based facilities. In connection with our organizational efficiency initiative, in the year ending December 31, 2014, we expect to incur incremental costs of approximately $5 million associated with one-time termination benefit plans, other severance-related compensation, accelerated share-based compensation under our long-term incentive plan and the termination of executory agreements related to closing certain shore-based facilities.

Performance and Other Key Indicators

Contract backlog—The contract backlog for our contract drilling services segment was as follows:

	February 18, 2014	October 16, 2013	February 14, 2013
Contract backlog (a)		(In millions)	
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 19,690	$ 20,804	$ 19,144
Deepwater Floaters	1,209	1,362	2,127
Harsh Environment Floaters	1,887	2,279	1,942
Total High-Specification Floaters	22,786	24,445	23,213
Midwater Floaters	3,224	3,889	4,145
High-Specification Jackups	1,234	1,427	1,486
Total	$ 27,244	$ 29,761	$ 28,844

(a) 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.

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, which are excluded from the amounts presented for contract backlog.

Our contract backlog includes only firm commitments for our contract drilling services segment, which are represented by signed drilling contracts or, in some cases, by other definitive agreements awaiting contract execution. Our contract backlog includes amounts associated with our newbuild units that are currently under construction. The contractual operating dayrate may be higher than the actual dayrate we ultimately receive or an alternative contractual dayrate, such as a waiting-on-weather rate, repair rate, standby rate or force majeure rate, may apply under certain circumstances. The contractual operating dayrate may also be higher than the actual dayrate we ultimately receive because of a number of factors, including rig downtime or suspension of operations. In certain contracts, the dayrate may be reduced to zero if, for example, repairs extend beyond a stated period of time.

At February 18, 2014, the contract backlog and average contractual dayrates for our contract drilling services segment were as follows:

		For the years ending December 31,				
	Total	2014	2015	2016	2017	Thereafter
Contract backlog (a)	(In millions, except average dayrates)					
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 19,690	$ 3,660	$ 2,720	$ 2,301	$ 2,159	$ 8,850
Deepwater Floaters	1,209	672	394	143	—	—
Harsh Environment Floaters	1,887	934	621	220	112	—
Total High-Specification Floaters	22,786	5,266	3,735	2,664	2,271	8,850
Midwater Floaters	3,224	1,551	1,350	323	—	—
High-Specification Jackups	1,234	490	376	206	112	50
Total contract backlog	$ 27,244	$ 7,307	$ 5,461	$ 3,193	$ 2,383	$ 8,900
Average-contractual dayrates (b)						
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 543,000	$ 553,000	$ 551,000	$ 537,000	$ 532,000	$ 530,000
Deepwater Floaters	$ 377,000	$ 386,000	$ 381,000	$ 334,000	$ —	$ —
Harsh Environment Floaters	$ 513,000	$ 480,000	$ 529,000	$ 599,000	$ 589,000	$ —
Total High-Specification Floaters	$ 521,000	$ 511,000	$ 523,000	$ 525,000	$ 535,000	$ 530,000
Midwater Floaters	$ 370,000	$ 359,000	$ 378,000	$ 393,000	$ —	$ —
High-Specification Jackups	$ 160,000	$ 165,000	$ 161,000	$ 165,000	$ 143,000	$ 136,000
Total fleet average	$ 433,000	$ 415,000	$ 419,000	$ 447,000,	$ 474,000	$ 489,000

(a) 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.

(b) 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 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—The average daily revenue for our contract drilling services segment was as follows:

	Years ended December 31, 2013	2012	2011
Average daily revenue (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 500,200	$ 500,300	$ 461,000
Deepwater Floaters	$ 353,300	$ 338,200	$ 340,000
Harsh Environment Floaters	$ 451,700	$ 444,500	$ 428,400
Total High-Specification Floaters	$ 459,800	$ 455,000	$ 430,400
Midwater Floaters	$ 311,100	$ 262,200	$ 286,400
High-Specification Jackups	$ 164,400	$ 141,300	$ 108,500
Total fleet average daily revenue	$ 382,300	$ 370,300	$ 367,600

(a) 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.

Our average daily revenue fluctuates relative to market conditions and our revenue efficiency. Our total fleet average daily revenue is also affected by the mix of rig classes being operated, as Midwater Floaters and High-Specification Jackups are typically contracted at lower dayrates compared to High-Specification Floaters. We include newbuilds in the calculation when the rigs commence operations upon acceptance by the customer. We remove rigs from the calculation upon disposal, classification as held for sale or classification as discontinued operations.

Revenue efficiency—The revenue efficiency rates for our contract drilling services segment were as follows:

	Years ended December 31,		
	2013	2012	2011
Revenue efficiency (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	89%	93%	88%
Deepwater Floaters	91%	91%	91%
Harsh Environment Floaters	97%	97%	97%
Total High-Specification Floaters	91%	93%	90%
Midwater Floaters	94%	91%	93%
High-Specification Jackups	98%	95%	95%
Total fleet average revenue efficiency	92%	93%	91%

(a) 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.

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—The rig utilization rates for our contract drilling services segment were as follows:

	Years ended December 31,		
	2013	2012	2011
Rig utilization (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	92%	94%	88%
Deepwater Floaters	68%	61%	49%
Harsh Environment Floaters	100%	87%	94%
Total High-Specification Floaters	86%	83%	76%
Midwater Floaters	61%	66%	59%
High-Specification Jackups	91%	84%	57%
Total fleet average utilization	79%	78%	69%

(a) 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.

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.

Operating Results

Year ended December 31, 2013 compared to the year ended December 31, 2012

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

	Years ended December 31, 2013	Years ended December 31, 2012	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	23,687	23,577	110	—%
Average daily revenue	$ 382,300	$ 370,300	$ 12,000	3%
Revenue efficiency	92%	93%		
Rig utilization	79%	78%		
Contract drilling revenues	$ 9,070	$ 8,773	$ 297	3%
Other revenues	414	423	(9)	(2)%
	9,484	9,196	288	3%
Operating and maintenance expense	(5,791)	(6,106)	315	(5)%
Depreciation expense	(1,109)	(1,123)	14	(1)%
General and administrative expense	(286)	(282)	(4)	1%
Loss on impairment	(81)	(140)	59	(42)%
Gain on disposal of assets, net	7	36	(29)	(81)%
Operating income	2,224	1,581	643	41%
Other income (expense), net				
Interest income	52	56	(4)	(7)%
Interest expense, net of amounts capitalized	(584)	(723)	139	(19)%
Other, net	(28)	(48)	20	(42)%
Income from continuing operations before income tax expense	1,664	866	798	92%
Income tax expense	(258)	(50)	(208)	n/m
Income from continuing operations	$ 1,406	$ 816	$ 590	72%

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues increased for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to the following: (a) approximately $375 million of increased contract drilling revenues due to improved dayrates, (b) approximately $90 million of increased contract drilling revenues associated with our newbuild High-Specification Jackups that commenced operations during the year ended

December 31, 2013 and 2012, and (c) approximately $80 million of increased contract drilling revenues due to greater rig utilization caused by less time dedicated to shipyard projects and rig certifications. This increase was partially offset by (a) approximately $120 million of decreased contract drilling revenues caused by lower revenue efficiency and (b) approximately $105 million of decreased contract drilling revenues due to an increased number of rigs idle in the year ended December 31, 2013 compared to the year ended December 31, 2012.

Other revenues decreased for the year ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to reduced activity of our drilling management services due to decreased demand for these services.

Costs and expenses—Excluding the losses of $120 million and $756 million, recognized in the years ended December 31, 2013 and 2012, respectively, associated with contingencies related to the Macondo well incident, operating and maintenance costs and expenses increased for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to the following: (a) approximately $335 million of increased costs and expenses due to greater rig utilization and higher shipyard costs, including $50 million related to the reactivation of the Midwater Floater Sedco 712, and (b) approximately $40 million of increased costs and expenses associated with our newbuild High-Specification Jackups that commenced operations during the years ended December 31, 2013 and 2012. These increases were partially offset by approximately $50 million of decreased costs and expenses due to an increased number of rigs idle in 2013.

In the year ended December 31, 2013, we recognized an aggregate loss of $81 million associated with the impairment of assets, including $64 million 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, which were classified as assets held for sale at the time of impairment, and $17 million associated with the impairment of certain corporate assets. In the year ended December 31, 2012, we recognized a loss of $118 million associated with completing our measurement of the impairment of goodwill associated with our contract drilling services reporting unit and a loss of $22 million associated with the impairment of the customer relationship intangible assets attributed to our drilling management services reporting unit.

In the year ended December 31, 2013, we completed the sale of the Deepwater Floater Transocean Richardson along with related equipment and recognized a net gain of $33 million associated with the sale, partially offset by an aggregate net loss of $26 million associated with the disposal of assets unrelated to dispositions of rigs. In the year ended December 31, 2012, we completed the sale of the Deepwater Floaters Discoverer 534 and Jim Cunningham along with related equipment and recognized an aggregate net gain of $36 million associated with the sale.

Other income and expense—Interest expense, net of amounts capitalized, decreased in the year ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to approximately $150 million of decreased interest expense associated with debt repaid or redeemed in the year ended December 31, 2013, and $24 million of increased interest capitalization associated with our newbuild construction program, partially offset by $40 million of increased interest expense associated with debt issued or bank credit agreements entered into in the year ended December 31, 2012.

In the year ended December 31, 2013, we recognized $28 million in 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 the Shelf Drilling preference shares and (c) a loss of $9 million associated with the termination of the interest rate swaps related to the TPDI Credit Facilities. In the year ended December 31, 2012, we recognized $48 million in other expense, net, primarily related to the following: (a) a loss of $27 million associated with currency exchange and (b) a loss of $24 million associated with the redeemed noncontrolling interest in TPDI.

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, 2013 and 2012, our annual effective tax rates were 20.0 percent and 17.8 percent, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as expenses for litigation matters, losses on impairment, gains on certain asset disposals and acquisition, costs for one-time termination benefits, and gains and losses on debt retirements. 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, 2013 and 2012, the effect of the various discrete period tax items was a net tax benefit of $82 million and a net tax benefit of $256 million, respectively. For the years ended December 31, 2013 and 2012, these discrete tax items, together with the excluded income and expense items noted above, resulted in effective tax rates of 15.5 percent and 5.8 percent, respectively, on income from continuing operations before income tax expense.

The relationship between our provision for or benefit from income taxes and our income before income taxes can vary significantly from period to period considering, among other factors, (a) the overall level of income before income taxes, (b) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (c) rig movements between taxing jurisdictions and (d) our rig operating structures. Generally, our 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, 2013 compared to the year ended December 31, 2012, the annual effective tax rate increased to 20.0 percent from 17.8 percent primarily due to changes in the blend of income that is taxed based on gross revenues versus income before taxes, the currency exchange effect of the weakened Norwegian krone relative to the U.S. dollar off-set by the effect of higher income before income taxes. With respect to the annual effective tax rate calculation for the year ended December 31, 2013, 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, Gabon and Mozambique. Conversely, the most significant countries in which we incurred 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.

Year ended December 31, 2012 compared to the year ended December 31, 2011

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

	Years ended December 31, 2012	Years ended December 31, 2011	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	23,577	20,017	3,560	18%
Average daily revenue	$ 370,300	$ 367,600	$ 2,700	1%
Revenue efficiency	93%	91%		
Rig utilization	78%	69%		
Contract drilling revenues	$ 8,773	$ 7,407	$ 1,366	18%
Other revenues	423	620	(197)	(32)%
	9,196	8,027	1,169	15%
Operating and maintenance expense	(6,106)	(6,179)	73	(1)%
Depreciation expense	(1,123)	(1,109)	(14)	1%
General and administrative expense	(282)	(288)	6	(2)%
Loss on impairment	(140)	(5,201)	5,061	(97)%
Gain (loss) on disposal of assets, net	36	(12)	48	n/m
Operating income (loss)	1,581	(4,762)	6,343	n/m
Other income (expense), net				
Interest income	56	44	12	27%
Interest expense, net of amounts capitalized	(723)	(621)	(102)	16%
Other, net	(48)	(99)	51	(52)%
Income (loss) from continuing operations before income tax expense	866	(5,438)	6,304	n/m
Income tax expense	(50)	(324)	274	(85)%
Income (loss) from continuing operations	$ 816	$ (5,762)	$ 6,578	n/m

"n/a" means not applicable.

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues increased for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily due to the following: (a) approximately $940 million of increased contract drilling revenues due to greater rig utilization caused by less time dedicated to shipyard projects and recertifications, a portion of which was associated with the post-Macondo regulatory and operating environment, (b) approximately

$330 million of increased contract drilling revenues associated with the operations of the two Harsh Environment Ultra-Deepwater semisubmersibles acquired in connection with our acquisition of Aker Drilling and our newbuild units that commenced operations in the years ended December 31, 2012 and 2011 and (c) approximately $140 million of increased contract drilling revenues due to improved dayrates.

Other revenues decreased for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily due to (a) approximately $178 million of decreased revenues associated with the continuing operations of our drilling management services due to reduced demand for these services in the U.K. and (b) approximately $50 million of decreased revenues related to our integrated services.

Costs and expenses—Excluding the losses of $756 million and $1.0 billion associated with contingencies related to the Macondo well incident recognized in the years ended December 31, 2012 and 2011, respectively, operating and maintenance costs and expenses increased for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to the following (a) $180 million of increased costs and expenses due to greater rig utilization and higher shipyard costs and (b) $160 million of increased costs and expenses associated with the operations of the two Harsh Environment Ultra-Deepwater semisubmersibles acquired in connection with our acquisition of Aker Drilling and our newbuilds that commenced operations during the years ended December 31, 2012 and 2011. Partially offsetting the increase was $35 million of decreased costs associated with our integrated services.

Depreciation expense increased primarily due to $31 million of additional depreciation expense related to two rigs acquired in connection with our acquisition of Aker Drilling in October 2011 and $16 million associated with three newbuilds, two Ultra-Deepwater Floaters and one High-Specification Jackup, which commenced operations in 2011 and 2012. Partially offsetting the increase was $33 million related to useful life extensions of three Midwater Floaters.

In the year ended December 31, 2012, we recognized a loss of $118 million associated with completing our measurement of the impairment of goodwill associated with our contract drilling services reporting unit. We had previously recognized an estimated loss of $5.2 billion, in the year ended December 31, 2011, due to a decline in projected cash flows and market valuations for this reporting unit. Additionally, in the year ended December 31, 2012, we recognized a loss of $22 million associated with the impairment of the customer relationship intangible assets attributed to our drilling management services reporting unit.

In the year ended December 31, 2012, we recognized a net gain of $36 million associated with the disposal of assets, primarily related to the completion of sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham. In the year ended December 31, 2011, we recognized a net loss of $12 million associated with the disposal of assets unrelated to dispositions of rigs.

Other income and expense—Interest expense, net of amounts capitalized, increased in the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily due to $204 million of increased interest expense associated with debt issued in the years ended December 31, 2012 and 2011 and debt assumed in our acquisition of Aker Drilling in the year ended December 31, 2011. Partially offsetting these increases was $86 million associated with debt repaid or repurchased in the years ended December 31, 2012 and 2011 and $15 million of increased interest capitalized for our newbuild projects.

In the year ended December 31, 2012, we recognized an aggregate loss of $27 million associated with currency exchange and a loss of $24 million related to the redeemed noncontrolling interest in TPDI. In the year ended December 31, 2011, we recognized an aggregate loss of $99 million associated with currency exchange, including a loss of $78 million associated with a forward exchange contract, which was not designated and did not qualify as a hedging instrument for accounting purposes.

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. The annual effective tax rates were 17.8 percent and 35.4 percent at December 31, 2012 and 2011, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as losses on impairment, costs for litigation matters, losses on our forward exchange contract, gains on certain asset disposals, costs related to acquisitions and gain on debt retirements. 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, 2012 and 2011, the impact of the various discrete period tax items was a net tax benefit of $256 million and a net tax expense of $12 million, respectively. For the years ended December 31, 2012 and 2011, these discrete tax items, coupled with the excluded income and expense items noted above, resulted in effective tax rates of 5.8 percent and (6.0) percent on income from continuing operations before income tax expense for the years ended December 31, 2012 and 2011, respectively.

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, 2012 compared to the year ended December 31, 2011, the annual effective tax rate decreased to 17.8 percent from 35.4 percent primarily due to the significant increase in income before income taxes and the currency exchange effect of the strengthened Norwegian krone relative to the U.S dollar. With respect to the annual effective tax rate calculation for the year ended December 31, 2012, 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 Ghana. Conversely, the most significant countries in which we operated during this period that impose income taxes based on income before income tax include Norway, Malaysia, 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.

Discontinued operations

Overview—In the three years ended December 31, 2013, we discontinued the operations of (a) the standard jackup and swamp barge contract drilling services, (b) the Caspian Sea contract drilling services, (c) the U.S. Gulf of Mexico drilling management services and (d) the oil and gas properties operating segment.

A summary of the results of our discontinued operations, before income taxes, was as follows:

	Years ended December 31,		
	2013	2012	2011
	(In millions)		
Loss on impairment of assets in discontinued operations	$ (14)	$ (986)	$ (38)
Gain on disposal of assets in discontinued operations, net	54	82	183
Other income (loss) from operations of discontinued operations	1	(118)	(24)

In the year ended December 31, 2013, other income from operations of discontinued operations was negligible, primarily as the result of the operations of standard jackups under operating agreements with Shelf Drilling. In the years ended December 31, 2012 and 2011, other loss from operations of discontinued operations was primarily attributable to the operations of the standard jackup and swamp barge contract drilling services. Losses on impairment and net gains on disposal of assets in discontinued operations are discussed below.

Standard jackup and swamp barge contract drilling services—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 sell the 46 standard jackups and one swamp barge in our fleet, reflecting our decision to discontinue operations associated with the standard jackup and swamp barge asset groups, components of our contract drilling operating services segment. On November 30, 2012, we completed the sale of 38 drilling units in these asset groups, along with related equipment, to Shelf Drilling in a series of related transactions.

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. The costs to us for providing such operating and transition services, including allocated indirect costs, have exceeded the amounts we receive from Shelf Drilling for providing such services. We have also agreed to provide a limited guarantee with respect to three standard jackups and in favor of Shelf Drilling's customer from the time the drilling contracts are novated through expiration of such drilling contracts, and we may be required to perform if Shelf Drilling becomes unable to do so. As of February 18, 2014, we operated seven standard jackups under operating agreements with Shelf Drilling.

In the year ended December 31, 2013, we recognized an aggregate loss of $14 million associated with the impairment of the standard jackups GSF Rig 127 and GSF Rig 134, which were classified as assets held for sale at the time of impairment.

In the year ended December 31, 2012, we recognized losses of $744 million and $112 million associated with the impairment of the long-lived assets and the goodwill, respectively, related to the standard jackup and swamp barge disposal group, which was classified as held for sale at the time of the impairments. In the year ended December 31, 2012, we also recognized a loss of $20 million, included in loss on impairment of assets in discontinued operations, associated with postemployment benefits for employees and contract labor directly related to this disposal group. Additionally, in the year ended December 31, 2012, we recognized an aggregate loss of $29 million associated with the impairment of the standard jackups GSF Adriatic II and GSF Rig 136, which were classified as assets held for sale at the time of impairment.

In the year ended December 31, 2011, we recognized an aggregate loss of $28 million, associated with the impairment of the standard jackups George H. Galloway, GSF Britannia, GSF Labrador and the swamp barge Searex IV, which were classified as assets held for sale at the time of impairment.

In the years ended December 31, 2013 and 2012, we recognized aggregate gains of $11 million and $8 million, respectively, associated with the sale of equipment and materials and supplies related to the sale transactions with Shelf Drilling. In the years ended December 31, 2013, 2012 and 2011, we recognized aggregate net gains of $44 million, $74 million and $32 million, respectively, associated with the sale of drilling units not related to the sale transactions with Shelf Drilling.

Caspian Sea contract drilling services—In February 2011, in connection with our efforts to dispose of non-strategic assets, we sold the subsidiary that owns the High-Specification Jackup Trident 20, located in the Caspian Sea. The disposal of this subsidiary, a component of our contract drilling services operating segment, reflects our decision to discontinue operations in the Caspian Sea. As a result of the sale, we recognized a net gain of $169 million associated with the disposal of the discontinued operations. Through June 2011, we continued to operate Trident 20 under a bareboat charter to perform services for the customer and the buyer reimbursed us for the approximate cost of providing these services. Additionally, we provided certain transition services to the buyer through September 2011.

U.S. Gulf of Mexico drilling management services—In March 2012, we announced our intent to discontinue drilling management operations in the shallow waters of the U.S. Gulf of Mexico, a component of our drilling management services operating segment, upon completion of our then existing contracts. In December 2012, we completed the final drilling management project and discontinued offering our drilling management services in this region. In the year ended December 31, 2012, we recognized an aggregate loss of $70 million associated with the impairment of the customer relationships intangible asset and the trade name intangible asset attributed to our drilling management services reporting unit.

Oil and gas properties—During the year ended December 31, 2011, in connection with our efforts to dispose of non-strategic assets, we committed to a plan to sell the assets, reflecting our decision to discontinue the operations of our oil and gas properties reporting unit, a component of our former other operations segment, which included the exploration, development and production activities performed by Challenger Minerals Inc., Challenger Minerals (North Sea) Limited and Challenger Minerals (Ghana) Limited. In the year ended December 31, 2011, we completed the sale of Challenger Minerals (North Sea) Limited. In the year ended December 31, 2012, we completed the sales of the assets of Challenger Minerals Inc. and Challenger Minerals (Ghana) Limited.

In the years ended December 31, 2012 and 2011, we recognized losses of $11 million and $10 million, respectively, associated with the impairment of our oil and gas properties, which were classified as assets held for sale at the time of impairment. In the years ended December 31, 2012 and 2011, we recognized net gains of $9 million and an aggregate net loss of $4 million, respectively, associated with the disposal of these assets.

See Notes to Consolidated Financial Statements—Note 7—Discontinued Operations.

Liquidity and Capital Resources

Sources and uses of cash

At December 31, 2013, we had $3.2 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, 2013, we estimate the amount of cash required for these purposes, which is not generally available to us for other uses, was approximately $1.5 billion.

In the year ended December 31, 2013, our primary sources of cash were our cash flows from operating activities, proceeds from asset disposals, proceeds from the sale of the Shelf Drilling preference shares and proceeds from restricted cash investments, net. Our primary uses of cash were capital expenditures, primarily associated with our newbuild projects, repayments of debt, payment of the first three installments of our distribution of qualifying additional paid-in capital to shareholders and payment of our Macondo well incident settlement obligations.

	Years ended December 31, 2013	Years ended December 31, 2012	Change
	(In millions)		
Cash flows from operating activities			
Net income (loss)	$ 1,407	$ (211)	$ 1,618
Amortization of drilling contract intangibles	(15)	(42)	27
Depreciation	1,109	1,306	(197)
Loss on impairment	95	1,126	(1,031)
Gain on disposal of assets, net	(61)	(118)	57
Other non-cash items, net	199	135	64
Changes in Macondo well incident assets and liabilities, net	(455)	763	(1,218)
Changes in other operating assets and liabilities, net	(361)	(251)	(110)
	$ 1,918	$ 2,708	$ (790)

Net cash provided by operating activities decreased primarily due to an aggregate cash payment of $564 million for the initial installments required under our Macondo well incident settlement obligations. In the year ended December 31, 2013 and 2012, net income and the changes in Macondo well incident assets and liabilities include non-cash losses of $134 million and $757 million, respectively, associated with contingencies related to the Macondo well incident.

	Years ended December 31, 2013	Years ended December 31, 2012	Change
	(In millions)		
Cash flows from investing activities			
Capital expenditures	$ (2,238)	$ (1,409)	$ (829)
Proceeds from disposal of assets, net	378	980	(602)
Proceeds from sale of preference shares	185	—	185
Other, net	17	40	(23)
	$ (1,658)	$ (389)	$ (1,269)

Net cash used in investing activities increased primarily due to an increase in capital expenditures associated with our major construction and other shipyard projects and a reduction in proceeds from disposal of assets. The proceeds from the sale of the Shelf Drilling preference shares partially offset these increased uses of cash.

	Years ended December 31, 2013	Years ended December 31, 2012	Change
	(In millions)		

Cash flows from financing activities			
Change in short-term borrowings, net	$ —	$ (260)	$ 260
Proceeds from debt	—	1,493	(1,493)
Repayments of debt	(1,692)	(2,282)	590
Proceeds from restricted cash investments, net	179	144	35
Distribution of qualifying additional paid-in capital	(606)	(276)	(330)
Other, net	(32)	(21)	(11)
	$ (2,151)	$ (1,202)	$ (949)

Net cash used in financing activities increased primarily due to the absence of cash proceeds from the issuance of debt in the year ended December 31, 2013 partially offset by a reduction of cash used to repay or repurchase debt during the year ended December 31, 2013 compared to the year ended December 31, 2012.

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 or new rig construction, including new rigs the construction of which we may begin without first obtaining customer contracts. Any such 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.

Our historical and projected capital expenditures and other capital additions, including capitalized interest, for our recently completed and ongoing major construction projects were as follows:

	Total costs through December 31, 2013	Expected costs for the year ending December 31, 2014	Estimated costs thereafter	Total estimated costs at completion
	(In millions)			
Transocean Siam Driller (a) (b)	$ 236	$ —	$ —	$ 236
Transocean Andaman (a) (b)	242	—	—	242
Transocean Ao Thai (a) (b)	242	—	—	242
Deepwater Asgard (c)	495	320	—	815
Deepwater Invictus (c)	244	546	—	790
Deepwater Thalassa (d)	293	113	434	840
Deepwater Proteus (d)	274	81	435	790
Deepwater Pontus (d)	141	173	476	790
Deepwater Poseidon (d)	142	157	491	790
Deepwater Conqueror (e)	108	131	561	800
High-Specification Jackup TBN1 (f)	44	7	204	255
High-Specification Jackup TBN2 (f)	44	7	204	255
High-Specification Jackup TBN3 (f)	44	6	205	255
High-Specification Jackup TBN4 (f)	44	5	206	255
High-Specification Jackup TBN5 (f)	44	5	206	255
Ultra-Deepwater drillship TBN1 (g)	—	44	601	645
Ultra-Deepwater drillship TBN2 (g)	—	38	622	660
Total	$ 2,637	$ 1,633	$ 4,645	$ 8,915

(a) The accumulated construction costs of these rigs are no longer included in construction work in progress, as the construction projects had been completed as of December 31, 2013.

(b) The High-Specification Jackups Transocean Siam Driller, Transocean Andaman and Transocean Ao Thai commenced operations in March 2013, May 2013 and October 2013, respectively.

(c) Deepwater Asgard and Deepwater Invictus, 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 second quarter of 2014. Total costs through December 31, 2013 include construction work in progress acquired in connection with our acquisition of Aker Drilling with an aggregate estimated fair value of $272 million.

(d) Deepwater Thalassa, Deepwater Proteus, Deepwater Pontus and Deepwater Poseidon, four newbuild Ultra-Deepwater drillships under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, are expected to commence operations in the first quarter of 2016, the second quarter of 2016, the first quarter of 2017 and the second quarter of 2017, respectively.

(e) 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.

(f) Our five unnamed Keppel FELS Super B 400 Bigfoot class design newbuild High-Specification Jackups under construction do not yet have drilling contracts and are expected to be delivered in the first quarter of 2016, the third quarter of 2016, the fourth quarter of 2016, the first quarter of 2017 and the third quarter of 2017, respectively.

(g) Our two unnamed dynamically positioned Ultra-Deepwater drillships under construction at the Juong Shipyard PTE Ltd. in Singapore do not yet have drilling contracts and are expected to be delivered in the second quarter of 2017 and the first quarter of 2018, respectively.

In the year ended December 31, 2013, our capital expenditures, including capitalized interest of $78 million, for our major construction projects were $1.4 billion, substantially all of which related to our contract drilling services segment. During the year ended December 31, 2013, we significantly expanded our expected future capital expenditures with our plan to construct five additional newbuild High-Specification Jackups and one additional newbuild Ultra-Deepwater drillship. Each of the shipyard contracts for the five newbuild High-Specification Jackups includes an option to order an additional jackup of the same design and specifications on similar terms. The first such option expires in November 2014, and the remaining four options expire in consecutive four-month intervals thereafter. On February 26, 2014, we entered into agreements for the construction of two newbuild dynamically positioned Ultra-Deepwater drillships. We also entered into an options agreement to order up to three additional newbuild drillships with the same design and specifications. The first option must be exercised within one year, the second within 18 months and the final within 24 months. 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. See “Item 1A. Risk Factors—Risks related to our business—Our shipyard projects and operations are subject to delays and cost overruns.”

For the year ending December 31, 2014, we expect our capital expenditures to be approximately $2.6 billion, including approximately $1.6 billion for our major construction projects. 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 regulatory environment, customer interest in newbuild construction and customer requested capital improvements and equipment for which the customer agrees to reimburse us.

We intend to fund the future cash requirements for our projected capital expenditures through available cash balances, cash generated from operations, asset sales and sales of interests in entities we control. We also have available credit under our revolving credit facilities (see "—Sources and uses of liquidity"), and we may utilize a portion of this available credit or other commercial bank or capital market financings. Economic conditions could impact the availability of these sources of funding. See "Item 1A. Risk Factors—Risks related to our business—Worldwide financial and economic conditions could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows."

Dispositions—From time to time, we may also review the possible disposition of non-strategic drilling units. 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, in connection with the disposal of these assets, we received net cash proceeds of $142 million and recognized a gain of $33 million, or $22 million, net of tax. Subsequent to December 31, 2013, we completed the sale of the High-Specification Jackup GSF Monitor along with related equipment.

During the year ended December 31, 2012, we completed the sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham along with related equipment. In connection with these sales, we received aggregate net cash proceeds of $178 million and recognized an aggregate net gain of $51 million.

In the three years ended December 31, 2013, we also completed the sales of 59 drilling units and other assets associated with our discontinued operations. See "—Results of Operations—Discontinued operations."

Sources and uses of liquidity

Overview—We expect to use existing cash balances, internally generated cash flows, borrowings under bank credit agreements and proceeds from the disposal of assets or proceeds from the sale of a noncontrolling interest in a MLP-type yield vehicle to fulfill anticipated obligations, such as scheduled debt maturities or other payments, repayment of debt due within one year, capital expenditures, shareholder-approved distributions, payments of our Macondo well incident settlement obligations, working capital and other needs in our operations. 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 or proceeds from the sale of a noncontrolling interest in a MLP-type yield vehicle to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

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 $1.5 billion. 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 bank credit agreements to maintain liquidity for short-term cash needs.

On January 3, 2013, we reached an agreement with the DOJ to resolve certain outstanding civil and potential criminal charges against us arising from the Macondo well incident (see "—Plea Agreement obligations" and "—Consent Decree obligations”). However, we are unable to predict the ultimate outcome of the investigations of the Macondo well incident and the DOJ lawsuits and other litigation related to other claims that were not addressed in our resolution with the DOJ. We can give no assurance that the matters arising out of the Macondo well incident will not adversely affect our liquidity in the future. See “—Item 1A. Risk Factors—Risks related to our business—Despite our settlement with the DOJ, we could have additional liabilities to the U.S. government and others. The ultimate outcome of investigations of the Macondo well incident, DOJ lawsuits and our settlement with the DOJ is uncertain.”

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, potential liability related to the Macondo well incident, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. Uncertainty related to our potential liabilities from the Macondo well incident has had, and could continue to have, an adverse effect on our business and our financial condition. 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. Uncertainty related to our potential liabilities from the Macondo well incident has had an adverse effect on our share price and could impact our ability to access capital markets in the future.

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 November 2013, our board of directors agreed to recommend that shareholders at the May 2014 annual general meeting approve a distribution of qualifying additional paid-in capital in the form of a U.S. dollar denominated dividend of $3.00 per outstanding share, for an aggregate amount of $1.1 billion, payable in four installments. The recommendation will be subject to shareholder approval at our 2014 annual general meeting, and certain limitations under Swiss law.

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 installments, subject to certain limitations. We did not pay the distribution of qualifying additional paid-in capital with respect to our shares held in treasury or held by our subsidiary. 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 expect to make the final installment of $202 million to shareholders of record as of February 21, 2014. At February 18, 2014, the carrying amount of the unpaid distribution payable was $202 million.

Primary Revolving Credit Facilities—We have a $2.0 billion five-year revolving credit facility, established under a bank credit agreement dated November 1, 2011, as amended, that is scheduled to expire on November 1, 2016 (the "Five-Year Revolving Credit Facility"). We also have a $900 million three-year secured revolving credit facility, established under a bank credit agreement dated October 25, 2012, that is scheduled to expire on October 25, 2015 (the "Three-Year Secured Revolving Credit Facility" and, together with the Five-Year Revolving Credit Facility, the "Primary Revolving Credit Facilities"). The Five-Year Revolving Credit Facility includes a $1.0 billion sublimit for the issuance of letters of credit, and borrowings under the Five-Year Revolving Credit Facility are guaranteed by Transocean Ltd. Borrowings under the Three-Year Secured Revolving Credit Facility are secured by the Ultra-Deepwater Floaters Deepwater Champion, Discoverer Americas and Discoverer Inspiration and are guaranteed by Transocean Ltd. and Transocean Inc.

Among other things, the Primary Revolving Credit Facilities include limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Primary Revolving Credit Facilities also include a covenant imposing a maximum debt to tangible capitalization ratio of 0.6 to 1.0. As of December 31, 2013, our debt to tangible capitalization ratio, as defined, was 0.4 to 1.0. In order to borrow under the Primary Revolving Credit Facilities 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. In order to borrow under the Three-Year Secured Revolving Credit Facility, we must also, at the time of the borrowing request, satisfy a collateral maintenance test. Commitments and borrowings under the Three-Year Secured Revolving Credit Facility are subject to mandatory reductions and prepayments, respectively, if a mortgaged rig is sold, an event of loss with respect to a mortgaged rig occurs, a collateral maintenance test is not satisfied or certain other events occur. Repayment of borrowings under the Primary Revolving Credit Facilities 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 bank credit agreements, our capital lease contract or any other debt owed to unaffiliated entities that exceeds $125 million could trigger a default under the Primary Revolving Credit Facilities and, if not waived by the lenders, could cause us to lose access to the Primary Revolving Credit Facilities and result in the foreclosure of the liens securing the Three-Year Secured Revolving Credit Facility.

Our commitment fee and lending margin under the Primary Revolving Credit Facilities are subject to change based on the credit rating of our non-credit enhanced senior unsecured long-term debt ("Debt Rating"). For the Five-Year Revolving Credit Facility, if our Debt Rating falls below investment grade, the commitment fee will increase from 0.275 percent to 0.325 percent and the lending margin will increase from 1.625 percent to 2.0 percent. For the Three-Year Secured Revolving Credit Facility, if our Debt Rating falls below investment grade, the commitment fee will increase from 0.375 percent to 0.50 percent and the lending margin will increase from 2.0 percent to 2.5 percent.

At February 18, 2014, we had no borrowings outstanding, we had $20 million in letters of credit issued, and we had $2.0 billion of available borrowing capacity under the Five-Year Revolving Credit Facility. At February 18, 2014, we had no borrowings outstanding, and we had $900 million of available borrowing capacity under the Three-Year Secured Revolving Credit Facility.

Debt issuance—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. We are required to pay interest on the 2012 Senior Notes on April 15 and October 15 of each year. 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. 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. At February 18, 2014, $750 million aggregate principal amount of the 2.5% Senior Notes due 2017 and $750 million aggregate principal amount of the 3.8% Senior Notes due 2022 were outstanding.

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"), 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 18, 2014, borrowings of $270 million and $270 million were outstanding under Eksportfinans Loan A and Eksportfinans Loan B, respectively.

The Eksportfinans Loans require restricted cash investments to remain on deposit 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 18, 2014, the aggregate balance of the Eksportfinans Restricted Cash Investments was $540 million.

Debt repayments—ADDCL had a senior secured credit facility, comprised of Tranche A for $215 million and Tranche C for $399 million, established under a bank credit agreement that was scheduled to expire in December 2017 (the "ADDCL Primary Loan Facility"). Unaffiliated financial institutions provided the commitment for and borrowings under Tranche A, and one of our subsidiaries provided the commitment for Tranche C. ADDCL also had a $90 million secondary credit facility, established under a bank credit agreement that was scheduled to expire in December 2015 (the "ADDCL Secondary Loan Facility" and together with the ADDCL Primary Loan Facility, the "ADDCL Credit Facilities"). One of our subsidiaries provided 65 percent of the total commitment under the ADDCL Secondary Loan Facility. ADDCL was required to maintain certain cash balances in restricted accounts for the payment of the scheduled installments on the ADDCL Credit Facilities. On February 12, 2014, we repaid the remaining borrowings of $163 million outstanding under the ADDCL Credit Facilities and terminated the bank credit agreement under which the credit facilities were established. In connection with the repayment of borrowings under the ADDCL Credit Facilities, the restricted cash investments were released.

We had a $1.265 billion secured credit facility, comprised of a $1.0 billion senior term loan, a $190 million junior term loan and a $75 million revolving credit facility, established under a bank credit agreement that was scheduled to expire in March 2015 (the "TPDI Credit Facilities"). One of our subsidiaries participated in the term loan with an aggregate commitment of $595 million. In June 2013, we repaid the $735 million of borrowings outstanding under the TPDI Credit Facilities, of which $367 million 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 facilities were established.

During the year ended December 31, 2013, we also repaid the outstanding $250 million and $500 million aggregate principal amount of the 5% Notes due February 2013 and the 5.25% Senior Notes due March 2013, respectively, as of the stated maturity dates.

Debt redemptions—Holders of the Series C Convertible Senior Notes had the right to require us to repurchase all or any portion of such holders' notes on December 14, 2012. As a result, in December 2012, we were required to repurchase an aggregate principal amount of $1.7 billion of our Series C Convertible Senior Notes for an aggregate cash payment of $1.7 billion. On February 7, 2013, we redeemed the remaining aggregate principal amount of $62 million of our Series C Convertible Senior Notes for an aggregate cash payment of $62 million.

We were obligors of the Callable Bonds, issued on February 21, 2011, which were publicly traded on the Oslo Stock Exchange. The FRN Callable Bonds and the 11% Callable Bonds were denominated in Norwegian kroner in the aggregate principal amounts of NOK 940 million and NOK 560 million, respectively. On March 6, 2013, we redeemed the FRN Callable Bonds and the 11% Callable Bonds with aggregate outstanding principal amounts of NOK 940 million and NOK 560 million, equivalent to $164 million and $98 million, respectively, using an exchange rate of NOK 5.73 to $1.00. In connection with the redemption, we made an aggregate cash payment of NOK 1,567 million, equivalent to $273 million.

Capital lease contract—Petrobras 10000 is held by one of our subsidiaries under a capital lease contract that requires scheduled monthly payments of $6 million through its stated maturity on August 4, 2029, at which time our subsidiary will have the right and obligation to acquire Petrobras 10000 from the lessor for one dollar. Upon the occurrence of certain termination events, our subsidiary is also required to purchase Petrobras 10000 and pay a termination amount determined by a formula based upon the total cost of the drillship. The capital lease contract includes limitations on creating liens on Petrobras 10000 and requires our subsidiary to make certain representations in connection with each monthly payment, including with respect to the absence of pending or threatened litigation or other proceedings against our subsidiary or any of its affiliates, which, if determined adversely, could have a material adverse effect on our subsidiary's ability to perform its obligations under the capital lease contract. Additionally, Transocean Inc. has guaranteed the obligations under the capital lease contract, and Transocean Inc. is required to maintain an adjusted net worth, as defined, of at least $5.0 billion as of the end of each fiscal quarter. In the event Transocean Inc. does not satisfy this covenant at the end of any fiscal quarter, it is required to deposit the deficit amount, determined as the difference between $5.0 billion and the adjusted net worth for such fiscal quarter, into an escrow account for the benefit of the lessor. At February 18, 2014, $635 million was outstanding under the capital lease contract.

Plea Agreement obligations—Pursuant to a cooperation guilty plea agreement by and among the 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 a total of $150 million to the National Fish & Wildlife Foundation, and $150 million to the National Academy of Sciences. In the year ended December 31, 2013, we made an aggregate cash payment of $160 million in satisfaction of amounts due under the Plea Agreement, including $100 million for the payment of the criminal fine, $58 million for the payment to the National Fish and Wildlife Foundation and $2 million for the payment to the National Academy of Sciences. Subsequent to December 31, 2013, we made an aggregate cash payment of $60 million as required under the Plea Agreement. At February 18, 2014, the remaining balance of our Plea Agreement obligations was $180 million, payable as follows: (a) $39 million payable to the National Fish and Wildlife Foundation, which is due on or before February 13, 2015 and (b) $141 million payable to the National Academy of Sciences, $21 million of which is due on or before February 13, 2015, $60 million of which is due on or before February 12, 2016 and $60 million of which is due on or before February 14, 2017.

Consent Decree obligations—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 rate of 2.15 percent. On March 15, 2013, we paid our initial installment of $404 million, including interest. At February 18, 2014, the remaining balance of our Consent Decree obligations was $600 million, payable as follows: (a) $400 million, plus interest, on or before February 19, 2014; and (b) $200 million, plus interest, on or before February 19, 2015.

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 $3.9 billion at an exchange rate as of the close of trading on February 18, 2014 of $1.00 to CHF 0.89. 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 a further three-year repurchase period through May 23, 2016. In the year ended December 31, 2013, we did not purchase shares under our share repurchase program.

We may decide, based upon our ongoing capital requirements, our program of distributions to our shareholders, the price of our shares, matters relating to the Macondo well incident, 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 either, with respect to the U.S. market, 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 or, with respect to the Swiss market, on the second trading line for our shares on the SIX. Repurchases could also be made by tender offer, in privately negotiated transactions or by any other share repurchase method. Any repurchased shares would be held by us for cancellation by the shareholders at a future annual general meeting. The share repurchase program could be suspended or discontinued by our board of directors or company management, as applicable, at any time.

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 18, 2014, Transocean Inc., our wholly owned subsidiary, held as treasury shares approximately three 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 seven 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, 2013, our contractual obligations stated at face value, were as follows:

	For the years ending December 31,				
	Total	2014	2015 - 2016	2017 - 2018	Thereafter
			(in millions)		
Contractual obligations					
Debt	$ 9,898	$ 140	$ 2,379	$ 2,171	$ 5,208
Debt of consolidated variable interest entities	163	163	—	—	—
Interest on debt (a)	5,517	560	1,054	795	3,108
Capital lease obligation (b)	1,118	66	143	144	765
Plea Agreement obligations	240	60	120	60	—
Consent Decree obligations (c)	615	411	204	—	—
Distribution of qualifying additional paid-in capital	202	202	—	—	—
Operating lease obligations	178	25	45	21	87
Purchase obligations	4,554	1,691	2,510	353	—
Total (d)	$ 22,485	$ 3,318	$ 6,455	$ 3,544	$ 9,168

(a) Interest on our consolidated debt.

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

(c) Includes interest on our Consent Decree obligations.

(d) As of December 31, 2013, our defined benefit pension and other postretirement plans represented an aggregate liability of $417 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 14—Postemployment Benefit Plans.

As of December 31, 2013, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of $502 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.

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, India, Indonesia, Egypt and the U.S. 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, 2013, these obligations stated in U.S. dollar equivalents and their time to expiration were as follows:

	For the years ending December 31,				
	Total	2014	2015 - 2016	2017 - 2018	Thereafter
			(in millions)		
Other commercial commitments					
Standby letters of credit (a)	$ 575	$ 474	$ 87	$ 14	$ —
Surety bonds	6	6	—	—	—
Total	$ 581	$ 480	$ 87	$ 14	$ —

(a) Included in the $575 million outstanding standby letters of credit at December 31, 2013 were $104 million of standby letters of credit that we have agreed to maintain in support of the operations for Shelf Drilling for up to three years following the closing of the sale transactions (See Notes to Consolidated Financial Statements—Note 7—Discontinued Operations). Shelf Drilling is required to reimburse us in the event that standby letters of credit relating to this performance are called.

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, 2013, the cash investments held by the captive insurance company totaled $139 million, and the amount of such cash investments is expected to range from $120 million to $220 million by December 31, 2014. 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 13—Derivatives and Hedging.

Pension Plans and Other Postretirement Benefit Plans

Overview—We maintain a qualified defined benefit pension plan in the U.S. (the "U.S. Plan") covering substantially all U.S. employees. We also maintain a funded supplemental benefit plan (the "Supplemental Plan") that offers benefits to certain employees that are ineligible for benefits under the U.S. Plan and two unfunded supplemental benefit plans (the "Other Supplemental Plans") that provide certain eligible employees with benefits in excess of those allowed under the U.S. Plan. Additionally, we maintain two funded and two unfunded defined benefit plans (collectively, the "Frozen Plans") that we assumed in connection with our mergers with GlobalSantaFe and R&B Falcon Corporation, all of which were frozen prior to the respective mergers and for which benefits no longer accrue but the pension obligations have not been fully distributed. We refer to the U.S. Plan, the Supplemental Plan, the Other Supplemental Plans and the Frozen Plans, collectively, as the "U.S. Plans."

We maintain a defined benefit plan in the U.K. (the "U.K. Plan") covering certain current and former employees in the U.K. We also provide several funded defined benefit plans, three of which we assumed in connection with our acquisition of Aker Drilling, which are primarily group pension schemes with life insurance companies, and two unfunded plans, covering our eligible Norway employees and former employees (the "Norway Plans"). We also maintain unfunded defined benefit plans (the "Other Plans") that provide retirement and severance benefits for certain of our Indonesian, Nigerian and Egyptian employees. We refer to the U.K. Plan, the Norway Plans and the Other Plans, 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.

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, 2013				Year ended December 31, 2012			
	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)	$ 95	$ 34	$ 3	$ 132	$ 89	$ 57	$ 3	$ 149
Other comprehensive income (loss)	271	(34)	7	244	(32)	31	(4)	(5)
Employer contributions	64	50	1	115	108	49	2	159
At end of period:								
Accumulated benefit obligation	$ 1,210	$ 490	$ 53	$ 1,753	$ 1,255	$ 434	$ 58	$ 1,747
Projected benefit obligation	1,380	573	53	2,006	1,452	499	58	2,009
Fair value of plan assets	1,116	481	—	1,597	948	422	—	1,370
Funded status	(264)	(92)	(53)	(409)	(504)	(77)	(58)	(639)
Weighted-Average Assumptions -Net periodic benefit costs								
Discount rate (b)	4.19%	5.13%	3.39%	4.43%	4.67%	5.43%	4.27%	4.85%
Long-term rate of return (c)	7.48%	5.79%	n/a	6.97%	7.47%	6.07%	n/a	7.02%
Compensation trend rate (b)	4.22%	4.21%	n/a	4.22%	4.22%	4.61%	n/a	4.32%
Health care cost trend rate-initial	n/a	n/a	8.07%	8.07%	n/a	n/a	8.08%	8.08%
Health care cost trend rate-ultimate (d)	n/a	n/a	5.00%	5.00%	n/a	n/a	5.00%	5.00%
-Benefit obligations								
Discount rate (b)	5.01%	4.92%	4.54%	4.97%	4.19%	5.37%	3.63%	4.48%
	4.24%	4.57%	n/a	4.35%	4.21%	4.38%	n/a	4.25%

Compensation trend rate (b)

"n/a" means not applicable.

(a) Net periodic benefit costs were reduced by expected returns on plan assets of $95 million and $84 million in the years ended December 31, 2013 and 2012, respectively.

(b) Weighted-average based on relative average projected benefit obligation for the year.

(c) Weighted-average based on relative average fair value of plan assets for the year.

(d) Ultimate health care trend rate is expected to be reached in 2020.

Net periodic benefit cost—In the year ended December 31, 2013, net periodic benefit costs decreased by $17 million primarily due to an increase in interest rates as well as favorable asset performance. For the year ending December 31, 2014, we expect net periodic benefit costs to decrease by $30 million compared to the net periodic benefit costs recognized in the year ended December 31, 2013 primarily due to the termination of benefits as a result of discontinued operations affecting our non-US Plans, partially offset by an increase in net periodic benefit costs for the U.S. Plans. Net periodic benefit costs for the U.S. Plans increased by $6 million primarily due to a decline in discount rates during 2013.

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, 2013, plan assets of the funded Transocean Plans were favorably impacted by improvements in world equity markets, given the allocation of approximately 62.96 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, 2013, the fair value of the investments in the funded Transocean Plans increased by $227 million, or 17 percent, due to investment returns of $194 million, funding contributions of $43 million, net of benefits paid, and currency revaluations of $10 million in connection with the funded Non-U.S. Plans.

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 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, 2013, we contributed $115 million and participants contributed $4 million to the Transocean Plans and the OPEB Plans. In the year ended December 31, 2012, we contributed $159 million and participants contributed $3 million to the Transocean Plans and the OPEB Plans.

For the year ending December 31, 2014, we expect to contribute $69 million to the Transocean Plans and $3 million to the OPEB Plans. These estimated contributions for the Transocean Plans are comprised of $41 million to meet minimum funding requirements for the funded U.S. Plans, $11 million to meet the funding requirements for the funded Non-U.S. Plans, and approximately $17 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,				
2014	$ 48	$ 22	$ 3	$ 73
2015	52	11	4	67
2016	57	11	4	72
2017	63	11	4	78
2018	67	13	4	84
2019-2023	420	86	21	527

Contingencies

Macondo well incident

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. Eleven persons were declared dead and others were injured as a result of the incident. At the time of the explosion, Deepwater Horizon was located approximately 41 miles off the coast of Louisiana in Mississippi Canyon Block 252 and was contracted to an affiliate of BP plc. (together with its affiliates, "BP"). The rig was declared a total loss. Although we are unable to estimate the full direct and indirect effect that the Macondo well incident will have on our business, the incident has had and could continue to have a material adverse effect on our consolidated statement of financial position, results of operations and cash flows.

We have recognized a liability for estimated loss contingencies associated with litigation and investigations resulting from the incident that we believe are probable and for which a reasonable estimate can be made. At December 31, 2013 and 2012, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $464 million and $1.9 billion, respectively, recorded in other current liabilities. The litigation and investigations also give rise to certain loss contingencies that we believe are either reasonably possible or probable but for which we do not believe a reasonable estimate can be made. Although we have not recognized a liability for such loss contingencies, these contingencies could result in liabilities that we ultimately recognize.

We have also recognized an asset associated with the portion of our estimated losses, primarily related to the personal injury and fatality claims of our crew and vendors, that we believe is probable of recovery from insurance. At December 31, 2013 and 2012, the insurance recoverable asset was $10 million and $153 million, respectively, 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. Our estimates involve a significant amount of judgment. As a result of new information or future developments, we may increase our estimated loss contingencies arising out of the Macondo well incident or reduce our estimated recoveries from insurance, and the resulting losses could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

We can provide no assurance as to the outcome of the trial, the timing of any upcoming phase of trial or ruling, 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 settlement. We can provide no assurance as to the estimated costs, insurance recoveries, or other actions that will result from the Macondo well incident.

Multidistrict litigation proceeding—Many of the Macondo well related claims are pending in the U.S. District Court, Eastern District of Louisiana (the "MDL Court"). In March 2012, BP and the Plaintiff's Steering Committee (the "PSC") announced that they had agreed to a partial settlement related primarily to private party environmental and economic loss claims as well as response effort related claims (the "BP/PSC Settlement"). On December 21, 2012, the MDL Court granted final approval of the economic and property damage class settlement between BP and the PSC. Various parties who objected to the BP/PSC Settlement filed appeals in the Fifth Circuit Court of Appeals challenging the MDL Court's final approval of the BP/PSC Settlement. BP filed appeals in the Fifth Circuit Court of Appeals challenging the manner in which the BP/PSC Settlement has been interpreted by the MDL Court with respect to business economic loss claims ("BEL Claims"). In these appeals, BP argues that, if the MDL Court's interpretation of the settlement with respect to BEL Claims is not overturned, the entire BP/PSC Settlement is invalid and should not have been approved. On October 2, 2013, a panel of the Fifth Circuit Court of Appeals issued an opinion questioning the manner in which the settlement has been interpreted with respect to BEL Claims. On December 2, 2013, that panel ordered a temporary halt to certain of the BEL Claims, pending further proceedings in the MDL Court. On January 10, 2014, another panel of the Fifth Circuit Court of Appeals affirmed the MDL Court's final approval of the BP/PSC Settlement. Thereafter, BP and certain plaintiffs who objected to the settlement filed petitions seeking en banc review by the entire Fifth Circuit of the legal validity of the BP/PSC Settlement. The PSC moved to dismiss BP's petition for rehearing for lack of jurisdiction. On February 6, 2014, responses were filed to the petitions for rehearing en banc and for the motion to dismiss.

In December 2012, in response to the BP/PSC Settlement, we filed three motions seeking partial summary judgment on various claims, including punitive damages claims. If successful, these motions would eliminate or reduce our exposure to punitive damages. The MDL Court has not yet ruled on these motions.

The first phase of the trial began on February 25, 2013 and testimony concluded on April 17, 2013. This phase addressed fault issues, including negligence, gross negligence, or other bases of liability of the various defendants with respect to the cause of the blowout and the initiation of the oil spill, as well as limitation of liability issues. In June and July 2013, the parties filed post-trial briefs and proposed findings of fact and conclusions of law.

The second phase of the trial began on September 30, 2013, and taking of testimony concluded on October 17, 2013. This phase addressed conduct related to stopping the release of hydrocarbons after April 22, 2010 and quantification of the amount of oil discharged. On December 20, 2013, the parties filed post-trial briefs and proposed findings, and on January 24, 2014, the parties filed reply briefs. The MDL Court has not yet ruled on the issues tried in the first or second phases of the trial.

DOJ settlement—On January 3, 2013, we reached an agreement with the DOJ to resolve certain outstanding civil and potential criminal charges against us arising from the Macondo well incident. As part of this resolution, we agreed to a guilty plea ("Plea Agreement") and a civil consent decree ("Consent Decree") by which, among other things, we agreed to pay $1.4 billion in fines, recoveries and civil penalties, excluding interest, in scheduled payments through February 2017. On June 14, 2013, as required under the Consent Decree, we submitted a performance plan, containing among other required items, interim milestones for actions in specified areas and a proposed schedule for reports required under the Consent Decree. On January 2, 2014, the DOJ approved the performance plan.

Shareholder derivative claims—In June 2010, our shareholders filed two shareholder derivative suits in the state district court in Texas naming us as a nominal defendant and certain of our current and former officers and directors as defendants. These cases allege breach of fiduciary duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets in connection with the Macondo well incident. The plaintiffs are generally seeking to recover, on behalf of us, damages to Transocean Ltd. and disgorgement of all profits, benefits, and other compensation from the individual defendants. On August 29, 2013, the state district court of Texas dismissed the action in its entirety as to all defendants. Plaintiffs filed an appeal in the First Court of Appeals in Texas on September 6, 2013 and filed a brief in support of their appeal on November 27, 2013. On February 10, 2014, we filed our response to the appeal.

See Notes to Consolidated Financial Statements Note 15—Commitments and Contingencies and "Part I. Item 1A. Risk Factors—Risks Related to Our Business."

Insurance matters

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. As of December 31, 2013, the insured value of our drilling rig fleet was approximately $27.2 billion, excluding our rigs under construction.

We generally do not carry commercial market insurance coverage for loss of revenues, unless it is contractually required, 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.

See Notes to Consolidated Financial Statements Note 15—Commitments and Contingencies—Retained risk and "Part I. Item 1A. Risk Factors—Risks Related to Our Business—Our business involves numerous operating hazards."

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 criminal trial in Norway.

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 item, if successfully challenged, would result in net adjustments of approximately $290 million of additional taxes, excluding interest and penalties. 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 and cash flows. 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.

While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate liability to have a material adverse effect on our consolidated statement of financial position or results of operations, although it may have a material adverse effect on our consolidated cash flows.

See Notes to Consolidated Financial Statements—Note 6—Income Taxes.

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, 2013.

Related Party Transactions

Quantum Pacific Management Limited—On October 18, 2007, one of our subsidiaries acquired a 50 percent interest in TPDI, an entity formed to operate two Ultra-Deepwater Floaters, Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2. Until May 31, 2012, Quantum held the remaining 50 percent interest in TPDI. Quantum had the unilateral right to exchange its interest in TPDI for our shares or cash, at its election, measured at an amount based on an appraisal of the fair value of the drillships that are owned by TPDI, subject to certain adjustments. During the year ended December 31, 2012, Quantum exercised its rights under the put option agreement electing to exchange its interest in TPDI for our shares. We issued 8.7 million shares to Quantum, and as a result, TPDI became our wholly owned subsidiary. In the year ended December 31, 2012, under the terms of the put option agreement, we made a cash payment of $72 million to Quantum to settle TPDI’s working capital.

Critical Accounting Policies and Estimates

We have 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 discontinued operations, allowance for doubtful accounts, materials and supplies obsolescence, investments, property and equipment, goodwill, 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 these critical accounting 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, 2013, the liability for estimated tax exposures in our jurisdictions of operation was approximately $502 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, 2013, the amount of indefinitely reinvested earnings was approximately $2.5 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 $180 million to $250 million would be payable upon distribution of all previously unremitted earnings at December 31, 2013.

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. We did not make any significant changes to our valuation allowance against deferred tax assets during the years ended December 31, 2011, 2012 and 2013.

See Notes to Consolidated Financial Statements—Note 6—Income Taxes.

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 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.

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 either reasonably possible or probable but for which we do not believe a reasonable estimate can be made. Although we have not recognized a liability for such loss contingencies, these contingencies could increase the liabilities we ultimately recognize. As of December 31, 2013 and 2012, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $464 million and $1.9 billion, respectively, recorded in other current liabilities.

We have also recognized an asset associated with the portion of our estimated losses, primarily related to the personal injury and fatality claims of our crew and vendors, that we believe is probable of recovery from insurance. Although we have available policy limits that could result in additional amounts, such as legal costs, being recoverable from insurance, recovery of such additional amounts is not probable and we are not currently able to estimate such amounts. At December 31, 2013 and 2012, the insurance recoverable asset was $10 million and $153 million, respectively, recorded in other assets.

Our estimates involve a significant amount of judgment. Actual results may differ from our estimates. As a result of new information or future developments, we may adjust our estimated loss contingencies arising out of the Macondo well incident, and the resulting liabilities could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

See Notes to Consolidated Financial Statements—Note 15—Commitments and Contingencies.

Goodwill—We conduct impairment testing for our goodwill annually as of October 1 and more frequently, on an interim basis, when an event occurs or circumstances change that may indicate a reduction in the fair value of a reporting unit below its carrying amount. We test goodwill at the reporting unit level, which is defined as an operating segment or a component of an operating segment that constitutes a business for which financial information is available and is regularly reviewed by management. We have determined that our reporting units for this purpose are as follows: (1) contract drilling services and (2) drilling management services.

Before testing goodwill, we consider whether or not to first assess qualitative factors to determine whether the existence of events or circumstances lead to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether the two-step impairment test is required. If, as the result of our qualitative assessment, we determine that the two-step impairment test is required, or, alternatively, if we elect to forgo the qualitative assessment, we test goodwill for impairment by comparing the carrying amount of the reporting unit, including goodwill, to the fair value of the reporting unit.

To estimate the fair value of each reporting unit, we apply a variety of valuation methods, incorporating both income and market approaches. For our contract drilling services reporting unit, we estimate fair value using discounted cash flows, publicly traded company multiples and acquisition multiples. To develop the projected cash flows associated with our contract drilling services 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 projected cash flows using a long-term 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. To develop the publicly traded company multiples, we gather available market data for companies with operations similar to our reporting units and publicly available information for recent acquisitions in the marketplace.

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 in a reporting unit's fair value calculations could result in an estimate that is significantly below its carrying amount, which may indicate its goodwill is impaired.

As a result of our annual impairment test, performed as of October 1, 2011, we determined that the goodwill associated with our contract drilling services reporting unit was impaired due to a decline in projected cash flows and market valuations for this reporting unit. In the year ended December 31, 2011, we recognized a loss of $5.2 billion, representing our best estimate of the impairment of goodwill. In the year ended December 31, 2012, we completed our analysis and recognized an incremental loss of $118 million, as an adjustment to our original estimate of the impairment of goodwill.

In September 2012, 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. As a result of our decision to discontinue operations associated with these components of our contract drilling services operating segment, we allocated $112 million of goodwill to the disposal group based on the fair value of the disposal group relative to the fair value of the contract drilling services operating segment. We then determined that the disposal group was impaired since its aggregate carrying amount exceeded its aggregate fair value, and, as a result, we recognized a loss of $112 million on the impairment of the allocated goodwill.

In each of these cases, we estimated the implied fair value of the goodwill by applying a variety of valuation methods, incorporating the cost, 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 commodity prices, projected demand for our services, rig utilization and dayrates.

In the years ended December 31, 2013 and 2012, as a result of our annual impairment testing, we concluded that the goodwill associated with our contract drilling services reporting unit was not impaired. At December 31, 2013, the carrying amount of goodwill was $3.0 billion, representing nine percent of our total assets. See Notes to Consolidated Financial Statements—Note 5—Impairments, Note 7—Discontinued Operations and Note 11—Goodwill and Other Intangib Assets.

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.

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. 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, utilization and asset performance. Useful lives 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 would likely result in materially different net carrying amounts and depreciation expense for our assets. We reevaluate the remaining useful lives of our rigs when certain events occur that directly impact the useful lives 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, 2013, 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 $102 million and a hypothetical one-year decrease would cause an increase in our annual depreciation expense of approximately $192 million.

Impairment of long-lived assets—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, 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, Deepwater Floaters, Harsh Environment Floaters, Midwater Floaters, and High-Specification Jackups.

We assess recoverability of assets held and used by projecting undiscounted cash flows for the asset group being evaluated. When the carrying amount of the asset group is determined to be unrecoverable, we recognize an impairment loss, measured as the amount by which the carrying amount of the asset group exceeds its estimated fair value. The evaluation requires us to make judgments about long-term projections for future revenues and costs, dayrates, rig utilization and idle time. These projections involve uncertainties that rely on assumptions about demand for our services, future market conditions and technological developments. Significant and unanticipated changes to these 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.

At December 31, 2013, the carrying amount of our property and equipment was $21.7 billion, representing 67 percent of our total assets.

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, 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, 2013, a hypothetical percentage point decrease of the expected long-term rate of return assumption would result in an increase to net periodic benefit costs and approximately $15 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, 2013, a hypothetical one-half percentage point decrease of the discount rate would result in an increase to net periodic benefit costs of approximately $23 million.

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

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

Scheduled Maturity Date (a)

	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
Restricted cash investments								
Fixed rate (NOK)	$ 140	$ 140	$ 140	$ 140	$ 34	$ —	$ 594	$ 619
Average interest rate	4.15%	4.15%	4.15%	4.15%	4.15%	—%		
Debt								
Fixed rate (USD)	$ 20	$ 1,124	$ 1,025	$ 777	$ 1,276	$ 5,719	$ 9,941	$ 11,002
Average interest rate	7.76%	5.01%	5.12%	2.69%	6.31%	6.49%		
Fixed rate (NOK)	$ 140	$ 140	$ 140	$ 140	$ 34	$ —	$ 594	$ 619
Average interest rate	4.15%	4.15%	4.15%	4.15%	4.15%	—%		
Debt of consolidated variable interest entities								
Variable rate (USD)	$ 163	$ —	$ —	$ —	$ —	$ —	$ 163	$ 163
Average interest rate	1.31%	—%	—%	—%	—%	—%		

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

We have engaged in certain hedging activities designed to reduce our exposure to interest rate risk and currency exchange rate risk. See Notes to Consolidated Financial Statements—Note 13—Derivatives and Hedging.

Interest rate risk

At December 31, 2013 and 2012, the aggregate principal amount of our consolidated variable-rate debt was approximately $163 million and $1.1 billion, which represented two percent and nine percent of the aggregate principal amount of our total consolidated debt, respectively, including the effect of our hedging activities. At December 31, 2013, our consolidated variable-rate debt consisted of borrowings under the ADDCL Credit Facilities. At December 31, 2012, our consolidated variable-rate debt, excluding the effect of our hedging activities, consisted of the FRN Callable Bonds and borrowings under the ADDCL Credit Facilities and the TPDI Credit Facilities. Based upon variable-rate debt amounts outstanding as of December 31, 2013 and 2012, a hypothetical one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of approximately $2 million and $11 million, respectively.

At December 31, 2013 and 2012, the fair value of our consolidated debt was $11.8 billion and $14.1 billion, respectively. During the year ended December 31, 2013, the fair value of our consolidated debt decreased by $2.3 billion due to the repayment or redemption of $1.4 billion aggregate principal amount of debt and a decrease of approximately $500 million in the market valuation of our outstanding consolidated 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, 2013 and 2012, a hypothetical one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $32 million and $51 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, 2013, we had NOK 3.6 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.

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, 2013. In making this assessment, management used the criteria for internal control over financial reporting described in Internal Control-Integrated Framework, as published in 1992 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, 2013, 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Shareholders of Transocean Ltd. and Subsidiaries

We have audited Transocean Ltd. and Subsidiaries' internal control over financial reporting (the Company) as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 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, 2013, 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, 2013 and 2012, 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, 2013, and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 26, 2014

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 26, 2014

TRANSOCEAN LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per share data)

	Years ended December 31, 2013	2012	2011
Operating revenues			
Contract drilling revenues	$ 9,070	$ 8,773	$ 7,407
Other revenues	414	423	620
	9,484	9,196	8,027
Costs and expenses			
Operating and maintenance	5,791	6,106	6,179
Depreciation	1,109	1,123	1,109
General and administrative	286	282	288
	7,186	7,511	7,576
Loss on impairment	(81)	(140)	(5,201)
Gain (loss) on disposal of assets, net	7	36	(12)
Operating income (loss)	2,224	1,581	(4,762)
Other income (expense), net			
Interest income	52	56	44
Interest expense, net of amounts capitalized	(584)	(723)	(621)
Other, net	(28)	(48)	(99)
	(560)	(715)	(676)
Income (loss) from continuing operations before income tax expense	1,664	866	(5,438)
Income tax expense	258	50	324
Income (loss) from continuing operations	1,406	816	(5,762)
Income (loss) from discontinued operations, net of tax	1	(1,027)	85
Net income (loss)	1,407	(211)	(5,677)
Net income attributable to noncontrolling interest	—	8	77
Net income (loss) attributable to controlling interest	$ 1,407	$ (219)	$ (5,754)
Earnings (loss) per share-basic			
Earnings (loss) from continuing operations	$ 3.87	$ 2.27	$ (18.14)
Earnings (loss) from discontinued operations	—	(2.89)	0.26
Earnings (loss) per share	$ 3.87	$ (0.62)	$ (17.88)
Earnings (loss) per share-diluted			
Earnings (loss) from continuing operations	$ 3.87	$ 2.27	$ (18.14)
Earnings (loss) from discontinued operations	—	(2.89)	0.26
Earnings (loss) per share	$ 3.87	$ (0.62)	$ (17.88)

Weighted-average shares outstanding			
Basic	360	356	322
Diluted	360	356	322

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In millions)

	Years ended December 31, 2013	2012	2011
Net income (loss)	$ 1,407	$ (211)	$ (5,677)
Other comprehensive income (loss) before reclassifications			
Components of net periodic benefit costs	198	(52)	(204)
Gain (loss) on derivative instruments	(5)	3	(13)
Loss on marketable securities	—	—	(13)
Reclassifications to net income			
Components of net periodic benefit costs	49	47	25
(Gain) loss on derivative instruments	18	(1)	11
Loss on marketable securities	—	2	13
Other comprehensive income (loss) before income taxes	260	(1)	(181)
Income taxes related to other comprehensive income (loss)	2	(7)	13
Other comprehensive income (loss), net of income taxes	262	(8)	(168)
Total comprehensive income (loss)	1,669	(219)	(5,845)
Total comprehensive income attributable to noncontrolling interest	3	8	73
Total comprehensive income (loss) attributable to controlling interest	$ 1,666	$ (227)	$ (5,918)

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions, except share data)

	December 31, 2013	December 31, 2012
Assets		
Cash and cash equivalents	$ 3,243	$ 5,134
Accounts receivable, net		
Trade	2,112	1,940
Other	50	260
Materials and supplies, net	743	610
Assets held for sale	148	179
Deferred income taxes, net	151	142
Other current assets	325	382
Total current assets	6,772	8,647
Property and equipment	28,443	26,967
Less accumulated depreciation	(7,720)	(7,118)
Property and equipment of consolidated variable interest entities, net of accumulated depreciation	984	1,031
Property and equipment, net	21,707	20,880
Goodwill	2,987	2,987
Other assets	1,080	1,741
Total assets	$ 32,546	$ 34,255
Liabilities and equity		
Accounts payable	$ 1,106	$ 1,047
Accrued income taxes	53	116
Debt due within one year	160	1,339
Debt of consolidated variable interest entities due within one year	163	28
Other current liabilities	2,072	2,933
Total current liabilities	3,554	5,463
Long-term debt	10,379	10,929
Long-term debt of consolidated variable interest entities	—	163
Deferred income taxes, net	374	366
Other long-term liabilities	1,554	1,604
Total long-term liabilities	12,307	13,062
Commitments and contingencies		
Shares, CHF 15.00 par value, 373,830,649 authorized, 167,617,649 conditionally authorized, 373,830,649	5,147	5,130

issued and 360,764,100 outstanding at December 31, 2013 and 402,282,355 authorized 167,617,649 conditionally authorized, 373,830,649 issued and 359,505,251 outstanding at December 31, 2012		
Additional paid-in capital	6,784	7,521
Treasury shares, at cost, 2,863,267 held at December 31, 2013 and 2012	(240)	(240)
Retained earnings	5,262	3,855
Accumulated other comprehensive loss	(262)	(521)
Total controlling interest shareholders' equity	16,691	15,745
Noncontrolling interest	(6)	(15)
Total equity	16,685	15,730
Total liabilities and equity	$ 32,546	$ 34,255

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions)

	Years ended December 31,			Years ended December 31,		
	2013	2012	2011	2013	2012	2011
Shares		Shares			Amount	
Balance, beginning of period	360	350	319	$ 5,130	$ 4,982	$ 4,482
Issuance of shares under share-based compensation plans	1	1	1	17	14	12
Issuance of shares in exchange for noncontrolling interest	—	9	—	—	134	—
Issuance of shares in public offering	—	—	30	—	—	488
Balance, end of period	361	360	350	$ 5,147	$ 5,130	$ 4,982
Additional paid-in capital						
Balance, beginning of period				$ 7,521	$ 7,211	$ 7,504
Share-based compensation				113	97	95
Issuance of shares under share-based compensation plans				(34)	(17)	(18)
Issuance of shares in exchange for noncontrolling interest				—	233	—
Issuance of shares in public offering, net of issue costs				—	—	671
Obligation for distribution of qualifying additional paid-in capital				(808)	—	(1,035)
Other, net				(8)	(3)	(6)
Balance, end of period				$ 6,784	$ 7,521	$ 7,211
Treasury shares, at cost						