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

"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 CO2 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	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	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	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	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	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.

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Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 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						
Balance, beginning of period				$ (240)	$ (240)	$ (240)
Balance, end of period				$ (240)	$ (240)	$ (240)
Retained earnings						
Balance, beginning of period				$ 3,855	$ 4,180	$ 9,934
Net income (loss) attributable to controlling				1,407	(219)	(5,754)

interest			
Fair value adjustment of redeemable noncontrolling interest	—	(106)	—
Balance, end of period	$ 5,262	$ 3,855	$ 4,180
Accumulated other comprehensive loss			
Balance, beginning of period	$ (521)	$ (496)	$ (332)
Other comprehensive income (loss) attributable to controlling interest	259	(8)	(164)
Reclassification from redeemable noncontrolling interest	—	(17)	—
Balance, end of period	$ (262)	$ (521)	$ (496)
Total controlling interest shareholders' equity			
Balance, beginning of period	$ 15,745	$ 15,637	$ 21,348
Total comprehensive income (loss) attributable to controlling interest	1,666	(227)	(5,918)
Share-based compensation	113	97	95
Issuance of shares under share-based compensation plans	(17)	(3)	(6)
Issuance of shares in exchange for noncontrolling interest	—	367	—
Fair value adjustment of redeemable noncontrolling interest	—	(106)	—
Reclassification from redeemable noncontrolling interest	—	(17)	—
Issuance of shares in public offering, net of issue costs	—	—	1,159
Obligation for distribution of qualifying additional paid-in capital	(808)	—	(1,035)
Other, net	(8)	(3)	(6)
Balance, end of period	$ 16,691	$ 15,745	$ 15,637
Noncontrolling interest			
Balance, beginning of period	$ (15)	$ (10)	$ (8)
Total comprehensive income (loss) attributable to noncontrolling interest	3	(5)	(2)
Issuance of subsidiary equity to noncontrolling	6	—	—

interest			
Balance, end of period	$ (6)	$ (15)	$ (10)
Total equity			
Balance, beginning of period	$ 15,730	$ 15,627	$ 21,340
Total comprehensive income (loss)	1,669	(232)	(5,920)
Share-based compensation	113	97	95
Issuance of shares under share-based compensation plans	(17)	(3)	(6)
Issuance of shares in exchange for noncontrolling interest	—	367	—
Fair value adjustment of redeemable noncontrolling interest	—	(106)	—
Reclassification from redeemable noncontrolling interest	—	(17)	—
Issuance of shares in public offering, net of issue costs	—	—	1,159
Obligation for distribution of qualifying additional paid-in capital	(808)	—	(1,035)
Other, net	(2)	(3)	(6)
Balance, end of period	$ 16,685	$ 15,730	$ 15,627

See accompanying notes.

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

	Years ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income (loss)	$ 1,407	$ (211)	$ (5,677)
Adjustments to reconcile to net cash provided by operating activities:			
Amortization of drilling contract intangibles	(15)	(42)	(45)
Depreciation	1,109	1,123	1,109
Depreciation of assets in discontinued operations	—	183	342
Share-based compensation expense	113	97	95
Loss on impairment	81	140	5,201
Loss on impairment of assets in discontinued operations	14	986	38
(Gain) loss on disposal of assets, net	(7)	(36)	12
Gain on disposal of assets in discontinued operations, net	(54)	(82)	(183)
Amortization of debt issue costs, discounts and premiums, net	6	68	125
Deferred income tax benefit	(9)	(133)	(62)
Other, net	93	72	144
Changes in deferred revenue, net	(78)	(54)	(16)
Changes in deferred expenses, net	74	85	(61)
Changes in operating assets and liabilities	(816)	512	803
Net cash provided by operating activities	1,918	2,708	1,825
Cash flows from investing activities			
Capital expenditures	(2,238)	(1,303)	(974)
Capital expenditures for discontinued operations	—	(106)	(46)
Investment in business combination, net of cash acquired	—	—	(1,246)
Payment for settlement of forward exchange contract, net	—	—	(78)
Proceeds from disposal of assets, net	174	191	14
Proceeds from disposal of assets in discontinued operations, net	204	789	447
Proceeds from sale of preference shares	185	—	—
Other, net	17	40	(13)
Net cash used in investing activities	(1,658)	(389)	(1,896)
Cash flows from financing activities			
Changes in short-term borrowings, net	—	(260)	(88)
Proceeds from debt	—	1,493	2,939

Repayments of debt	(1,692)	(2,282)	(2,409)
Proceeds from restricted cash investments	298	311	479
Deposits to restricted cash investments	(119)	(167)	(523)
Proceeds from share issuance	—	—	1,211
Distribution of qualifying additional paid-in capital	(606)	(276)	(759)
Financing costs	—	(24)	(83)
Other, net	(32)	3	(33)
Net cash provided by (used in) financing activities	(2,151)	(1,202)	734
Net increase (decrease) in cash and cash equivalents	(1,891)	1,117	663
Cash and cash equivalents at beginning of period	5,134	4,017	3,354
Cash and cash equivalents at end of period	$ 3,243	$ 5,134	$ 4,017

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Nature of 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. We specialize in technically demanding sectors of the offshore drilling business with a particular focus on deepwater and harsh environment drilling services. Our mobile offshore drilling fleet is considered one of the most versatile fleets in the world. We contract our drilling rigs, related equipment and work crews predominantly on a dayrate basis to drill oil and gas wells. At December 31, 2013, we owned or had partial ownership interests in and operated 79 mobile offshore drilling units associated with our continuing operations. At December 31, 2013, 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 December 31, 2013, we also had seven Ultra-Deepwater drillships and five High-Specification Jackups under construction or under contract to be constructed. See Note 10—Drilling Fleet.

We also provide oil and gas drilling management services, drilling engineering and drilling project management services primarily in the North Sea, through Advanced Drilling Technology International Limited ("ADTI"), our wholly-owned United Kingdom ("U.K.") subsidiary. ADTI conducts drilling management services primarily either on a dayrate or on a completed-project, fixed-price or turnkey basis. See Note 27—Subsequent Events.

In November 2012, in connection with our plan to discontinue operations associated with the standard jackup and swamp barge asset groups, 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. Under operating agreements, we agreed to continue to operate these standard jackups on behalf of Shelf Drilling for periods ranging from nine months to 27 months, until expiration or novation of the underlying drilling contracts by Shelf Drilling. Under a transition services agreement, we agreed to provide certain transition services for a period of up to 18 months following the completion of the sale transactions. As of December 31, 2013, we operated seven standard jackups under operating agreements with Shelf Drilling. See Note 7—Discontinued Operations.

In March 2012, we announced our intent to discontinue drilling management operations in the shallow waters of the U.S. Gulf of Mexico, upon completion of our then existing contracts. In December 2012, we completed the final project of our drilling management services operations in the U.S. Gulf of Mexico and discontinued offering our drilling management services in this region. See Note 7—Discontinued Operations.

In March 2011, we committed to a plan to sell the assets and discontinue the operations of our oil and gas properties operating segment, which comprised the exploration, development and production activities performed by Challenger Minerals Inc., Challenger Minerals (North Sea) Limited and Challenger Minerals (Ghana) Limited (collectively, "CMI"). In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited, in April 2012, we completed the sale of the assets of Challenger Minerals Inc. and, in December 2012, we completed the sale of the assets of Challenger Minerals (Ghana) Limited. See Note 7—Discontinued Operations.

Note 2—Significant Accounting Policies

Accounting estimates—To prepare financial statements in accordance with accounting principles generally accepted in the U.S., we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates and assumptions, including those related to our discontinued operations, allowance for doubtful accounts, materials and supplies obsolescence, property and equipment, investments, notes receivable, goodwill, income taxes, contingencies, share-based compensation, defined benefit pension plans and other postretirement benefits. We base our estimates and assumptions on historical experience and on various other factors we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

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

Consolidation—We consolidate entities in which we have a majority voting interest and entities that meet the criteria for variable interest entities for which we are deemed to be the primary beneficiary for accounting purposes. We eliminate intercompany transactions and accounts in consolidation. We apply the equity method of accounting for an investment in an entity if we have the ability to exercise significant influence over the entity that (a) does not meet the variable interest entity criteria or (b) meets the variable interest entity criteria, but for which we are not deemed to be the primary beneficiary. We apply the cost method of accounting for an investment in an entity if we do not have the ability to exercise significant influence over the unconsolidated entity. See Note 4—Variable Interest Entities.

Discontinued operations—We present as discontinued operations the operating results of a component of our business that either has been disposed of or is classified as held for sale when both of the following conditions are met: (a) the operations and cash flows of the component have been or will be eliminated from our ongoing operations as a result of the disposal transaction and (b) we will not have any significant continuing involvement in the operations of the disposed component. For discontinued operations that are disposed of other than by sale, we present the operating results as discontinued in the period in which the disposal group is either abandoned, distributed or exchanged, depending on the manner of disposal. We consider a component of our business to be one that comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of our business. During the year ended December 31, 2012, we reclassified to discontinued operations the operating results, assets and liabilities associated with the operations of the standard jackup and swamp barge asset groups, components of our contract drilling services operating segment, and the operations of our U.S. Gulf of Mexico drilling management services, a component of our drilling management services operating segment. During the year ended December 31, 2011, we reclassified to discontinued operations the operating results, assets and liabilities associated with the operations of our Caspian Sea contract drilling operations, a component of our contract drilling services segment, and the operations of our oil and gas properties segment. See Note 7—Discontinued Operations and Note 27—Subsequent Events.

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

Included in our contract drilling revenues, we recognize amortization associated with our drilling contract intangible assets and liabilities. In connection with our business combination with GlobalSantaFe Corporation in November 2007, we recognized drilling contract intangible assets and liabilities for acquired drilling contracts for future contract drilling services. The terms of the acquired contracts include fixed dayrates that were above or below the market dayrates that were available for similar contracts as of the date of the business combination. We recognized the fair value adjustments as contract intangible assets and liabilities, recorded in other assets and other long-term liabilities, respectively. We amortize the resulting contract drilling intangible revenues based on the cash flows projected over the respective contract period and include such revenues in contract drilling revenues on our consolidated statements of operations. See Note 11—Goodwill and Other Intangible Assets.

Other revenues—Our other revenues represent those derived from drilling management services and customer reimbursable revenues. For fixed-price contracts associated with our drilling management services, we recognize revenues and expenses upon well completion and customer acceptance, and we recognize loss provisions on contracts in progress when losses are probable. We recognize customer reimbursable revenues as we bill our customers for reimbursement of costs associated with certain equipment, materials and supplies, subcontracted services, employee bonuses and other expenditures, resulting in little or no net effect on operating income since such recognition is concurrent with the recognition of the respective reimbursable costs in operating and maintenance expense.

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

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

We recognize share-based compensation expense in the same financial statement line item as cash compensation paid to the respective employees. We recognize cash flows resulting from the tax deduction benefits for awards in excess of recognized compensation costs as financing cash flows. In the years ended December 31, 2013, 2012 and 2011, share-based compensation expense was $113 million, $97 million and $95 million, respectively. In the years ended December 31, 2013, 2012 and 2011, income tax benefit on share-based compensation expense was $17 million, $12 million and $16 million, respectively. See Note 18—Share-Based Compensation Plans.

Capitalized interest—We capitalize interest costs for qualifying construction and upgrade projects. In the years ended December 31, 2013, 2012 and 2011, we capitalized interest costs of $78 million, $54 million and $39 million, respectively, for our construction work in progress.

Foreign currency—We consider the U.S. dollar to be the functional currency for all of our operations since the majority of our revenues and expenditures are denominated in U.S. dollars, which limits our exposure to currency exchange rate fluctuations. We recognize foreign currency exchange gains and losses in other, net. In the years ended December 31, 2013, 2012 and 2011, we recognized net foreign currency exchange losses of $11 million, $27 million and $99 million, respectively. See Note 13—Derivatives and Hedging.

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

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

We maintain liabilities for estimated tax exposures in our jurisdictions of operation, and we recognize the provisions and benefits resulting from changes to those liabilities in our income tax expense or benefit along with related interest and penalties. Tax exposure items include potential challenges to permanent establishment positions, intercompany pricing, disposition transactions, and withholding tax rates and their applicability. These tax exposures are resolved primarily through the settlement of audits within these tax jurisdictions or by judicial means, but can also be affected by changes in applicable tax law or other factors, which could cause us to revise past estimates. See Note 6—Income Taxes.

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

We maintain restricted cash investments that are pledged for debt service, as required under certain bank credit agreements. We classify such restricted cash investment balances in other current assets if the restriction is expected to expire within one year and in other assets if the restriction is expected to expire in greater than one year. At December 31, 2013, the aggregate carrying amount of our restricted cash investments was $624 million, of which $159 million and $465 million was classified in other current assets and other assets, respectively. At December 31, 2012, the aggregate carrying amount of our restricted cash investments was $861 million, of which $195 million and $666 million was classified in other current assets and other assets, respectively. See Note 12—Debt.

Accounts receivable—We derive a majority of our revenues from services to international oil companies and government-owned or government-controlled oil companies. We evaluate the credit quality of our customers on an ongoing basis, and we do not generally require collateral or other security to support customer receivables. We establish an allowance for doubtful accounts on a case-by-case basis, considering changes in the financial position of a customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. At December 31, 2013 and 2012, the allowance for doubtful accounts was $14 million and $20 million, respectively.

Materials and supplies—We record materials and supplies at their average cost less an allowance for obsolescence. We estimate the allowance for obsolescence based on historical experience and expectations for future use of the materials and supplies. At December 31, 2013 and 2012, the allowance for obsolescence was $80 million and $66 million, respectively.

Assets held for sale—We classify an asset as held for sale when the facts and circumstances meet the criteria for such classification, including the following: (a) we have committed to a plan to sell the asset, (b) the asset is available for immediate sale, (c) we have initiated actions to complete the sale, including locating a buyer, (d) the sale is expected to be completed within one year, (e) the asset is being actively marketed at a price that is reasonable relative to its fair value, and (f) the plan to sell is unlikely to be subject to significant changes or termination. At December 31, 2013 and 2012, the aggregate carrying amount of our assets held for sale was $148 million and $179 million, respectively. See Note 7—Discontinued Operations and Note 10—Drilling Fleet.

Property and equipment—The carrying amounts of our property and equipment, consisting primarily of offshore drilling rigs and related equipment, are based on our estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values of our rigs. These estimates, assumptions and judgments reflect both historical experience and expectations regarding future industry conditions and operations. At December 31, 2013, the aggregate carrying amount of our property and equipment represented approximately 67 percent of our total assets.

We compute depreciation using the straight-line method after allowing for salvage values. We capitalize expenditures for newbuilds, renewals, replacements and improvements, including capitalized interest, if applicable, and we recognize the expense for maintenance and repair costs as incurred. For newbuild construction projects, we also capitalize the initial preparation, mobilization and commissioning costs incurred until the drilling unit is placed into service. Upon sale or other disposition of an asset, we recognize a net gain or loss on disposal of the asset, which is measured as the difference between the net carrying amount of the asset and the net proceeds received.

The estimated original useful lives of our drilling units range from 18 to 35 years, our buildings and improvements range from 10 to 30 years and our machinery and equipment range from four to 12 years. From time to time, we may review the estimated remaining useful lives of our drilling units when events occur or circumstances change, and we may extend the useful life when such events and circumstances indicate that a drilling unit can operate beyond its remaining useful life. During the year ended December 31, 2013, we adjusted the useful lives for five rigs, extending the estimated useful lives from between 29 and 40 years to between 35 and 44 years. During the year ended December 31, 2012, we adjusted the useful lives for three rigs, extending the estimated useful lives from between 29 and 30 years to between 35 and 38 years. During the year ended December 31, 2011, we adjusted the useful lives for two rigs, extending the estimated useful lives from between 20 and 30 years to between 23 and 38 years. We deemed the life extensions appropriate for each of these rigs based on the respective contracts under which the rigs were operating and the additional life-extending work, upgrades and inspections we performed on the rigs. In each of the years ended December 31, 2013, 2012 and 2011, the changes in estimated useful lives of these rigs resulted in a reduction in annual depreciation expense of $3 million ($0.01 per diluted share), $27 million ($0.08 per diluted share) and $2 million ($0.01 per diluted share), respectively, which had no tax effect for any period.

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

For assets classified as held and used, we determine recoverability by evaluating the undiscounted estimated future net cash flows, based on projected dayrates and utilization, of the asset group under review. We consider our asset groups to be Ultra-Deepwater Floaters, Deepwater Floaters, Harsh Environment Floaters, Midwater Floaters and High-Specification Jackups. When an impairment of one or more of our asset groups is indicated, we measure the impairment as the amount by which the asset group's carrying amount exceeds its estimated fair value. We measure the fair values of our contract drilling asset groups by applying a variety of valuation methods, incorporating a combination of cost, income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. For our drilling management services customer relationships asset, which was fully impaired as of December 31, 2012, we estimated fair value using the excess earnings method, which applied the income approach. For an asset classified as held for sale, we consider the asset to be impaired to the extent its carrying amount exceeds its estimated fair value less cost to sell.

In the year ended December 31, 2012, we determined that the customer relationships intangible asset associated with our drilling management services reporting unit was impaired, and we recognized a loss of $22 million ($17 million, or $0.05 per diluted share, net of tax) associated with the impairment of the intangible asset.

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 indicate that the fair value of a reporting unit or the indefinite-lived intangible asset may have declined below its carrying value.

We test goodwill at the reporting unit level, which is defined as an operating segment or one level below an operating segment that constitutes a business for which financial information is available and is regularly reviewed by management. We have identified two reporting units for this purpose: (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.

For our contract drilling services reporting unit, we estimate fair value using projected 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 the projected cash flows using a long-term, risk-adjusted weighted-average cost of capital, which is based on our estimate of the investment returns that market participants would require for each of our reporting units. We derive publicly traded company multiples for companies with operations similar to our reporting units using observable information related to shares traded on stock exchanges and, when available, observable information related to recent acquisitions. If the reporting unit's carrying amount exceeds its fair value, we consider goodwill impaired and perform a second step to measure the amount of the impairment loss, if any.

As a result of our annual goodwill impairment test in the years ended December 31, 2013 and 2012, we concluded that goodwill was not impaired. During the year ended December 31, 2012, we conducted an interim test on the goodwill attributed to the standard jackup and swamp barge asset group. We determined that such goodwill was impaired and recognized a loss of $112 million ($0.31 per diluted share), which had no tax effect, (see Note 7—Discontinued Operations). 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 ($16.15 per diluted share), which had no tax effect, representing our best estimate of the impairment of goodwill attributable to our contract drilling services reporting unit. In the three months ended March 31, 2012, we completed our analysis and recognized an incremental adjustment of $118 million ($0.33 per diluted share), which had no tax effect, to our original estimate. See Note 5—Impairments and Note 11—Goodwill and Other Intangible Assets.

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

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

We may enter into fair value hedges to manage our exposure to changes in fair value of recognized assets or liabilities, such as fixed-rate debt, or of unrecognized firm commitments. For a derivative that is designated and qualifies as a fair value hedge, we simultaneously recognize in current period earnings the gains or losses on the derivative along with the offsetting losses or gains on the hedged item attributable to the hedged risk. The resulting ineffective portion, which is measured as the difference between the change in fair value of the derivative and the hedged item, is recognized in current period earnings. See Note 13—Derivatives and Hedging, Note 21—Financial Instruments and Note 22—Risk Concentration.

Pension and other postretirement benefits—We use a measurement date of January 1 for determining net periodic benefit costs and December 31 for determining plan benefit obligations and the fair values of plan assets. We determine our net periodic benefit costs based on a market-related value of assets that reduces year-to-year volatility by including investment gains or losses subject to amortization over a five-year period from the year in which they occur. Investment gains or losses for this purpose are measured as the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. If gains or losses exceed 10 percent of the greater of plan assets or plan liabilities, we amortize such gains or losses over the average expected future service period of the employee participants.

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

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

At December 31, 2013 and 2012, our pension and other postretirement benefit plan obligations represented an aggregate liability of $409 million and $639 million, respectively, representing the amount of their net underfunded status. In the years ended December 31, 2013, 2012 and 2011, net periodic benefit costs were $132 million, $149 million and $88 million, respectively. See Note 14—Postemployment Benefit Plans.

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

Reclassifications—We have made certain reclassifications, which did not have an effect on net income, to prior period amounts to conform with the current year's presentation. These reclassifications did not have a material effect on our consolidated statement of financial position, results of operations or cash flows.

Subsequent events—We evaluate subsequent events through the time of our filing on the date we issue our financial statements. See Note 27—Subsequent Events.

Note 3—New Accounting Pronouncements

Recently adopted accounting standards

Balance sheet—Effective January 1, 2013, we adopted the accounting standards update that expands the disclosure requirements for the offsetting of assets and liabilities related to certain financial instruments and derivative instruments. The update requires disclosures to present both gross information and net information for financial instruments and derivative instruments that are eligible for net presentation due to a right of offset, an enforceable master netting arrangement or similar agreement. Our adoption did not have a material effect on our disclosures contained in our notes to consolidated financial statements.

Accumulated other comprehensive income—Effective January 1, 2013, we adopted the accounting standards update that requires disclosure of additional information about reclassifications out of accumulated other comprehensive income and to present reclassifications by component when reporting changes in accumulated other comprehensive income balances. For significant amounts that are reclassified out of accumulated other comprehensive income to net income in their entirety during the reporting period, the update requires disclosure, either on the face of the statement or in the notes, of the effect on the line items in the statement where net income is presented. For significant amounts that are not required to be reclassified in their entirety to net income during the reporting period, the update requires cross-references in the notes to other disclosures that provide additional information about those amounts. Our adoption did not have a material effect on our consolidated statements of other comprehensive income or the disclosures contained in our notes to consolidated financial statements.

Recently issued accounting standards

Income taxes—Effective January 1, 2014, we will adopt the accounting standards update that requires an unrecognized tax benefit to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward if net settlement is required or expected. The update is effective for interim and annual periods beginning on or after December 15, 2013. We are evaluating the potential effect of this accounting standards update. However, we do not expect that our adoption will have a material effect on our consolidated balance sheets or the disclosures contained in our notes to consolidated financial statements.

Note 4—Variable Interest Entities

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

	Years ended December 31,	
	2013	2012
Assets	$ 1,280	$ 1,231
Liabilities	261	311
Net carrying amount	$ 1,019	$ 920

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

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

At December 31, 2013 and 2012, the aggregate carrying amount of assets of our consolidated variable interest entities that were pledged as security for the outstanding debt of our consolidated variable interest entities was $768 million and $805 million, respectively. See Note 12—Debt.

Unconsolidated variable interest entities—As holder of two notes receivable, we hold a variable interest in Awilco Drilling plc (“Awilco”), a U.K. company listed on the Oslo Stock Exchange. We determined that Awilco met the definition of variable interest entity since its equity at risk was insufficient to permit it to carry on its activities without additional subordinated financial support. We believe that we are not the primary beneficiary since we do not have the power to direct the activities that most significantly impact the entity’s economic performance. The notes receivable were originally accepted in exchange for, and are secured by, two drilling units. The notes receivable have stated interest rates of nine percent and are payable in scheduled quarterly installments of principal and interest through maturity in January 2015. We evaluate the credit quality and financial condition of Awilco quarterly. At December 31, 2013 and 2012, the aggregate carrying amount of the notes receivable was $93 million and $105 million, respectively. At December 31, 2013, our aggregate exposure to loss on the notes receivable was $93 million.

Note 5—Impairments

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

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

Goodwill—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 ($16.15 per diluted share), which had no tax effect. During the year ended December 31, 2012, we completed the measurement of the impairment and recognized an incremental adjustment to our original estimate in the amount of $118 million ($0.33 per diluted share), which had no tax effect. 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.

Definite-lived intangible assets—During the year ended December 31, 2012, we determined that the customer relationships intangible asset associated with the U.K. operations of our drilling management services reporting unit was impaired due to the diminishing demand for our drilling management services. We estimated the fair value of the customer relationships intangible asset using the multiperiod excess earnings method, a valuation method that applies the income approach. We estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the drilling management services reporting unit, such as future commodity prices, projected demand for our services, rig utilization and dayrates. In the year ended December 31, 2012, as a result of our valuation, we determined that the carrying amount of the customer relationships intangible asset exceeded its fair value, and we recognized a loss of $22 million ($17 million, or $0.05 per diluted share, net of tax) associated with the impairment of the intangible asset.

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TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – continued

Note 6—Income Taxes

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

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

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

	Years ended December 31,		
	2013	2012	2011
Current tax expense	$ 267	$ 183	$ 386
Deferred tax benefit	(9)	(133)	(62)
Income tax expense	$ 258	$ 50	$ 324

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

	Years ended December 31,		
	2013	2012	2011
Income tax expense at the Swiss federal statutory rate	$ 130	$ 68	$ (426)
Taxes on earnings subject to rates different than the Swiss federal statutory rate	185	141	221
Taxes on impairment loss subject to rates different than the Swiss federal statutory rate	5	5	409
Taxes on asset sales subject to rates different than the Swiss federal statutory rate	9	(1)	—
Taxes on litigation matters subject to rates different than the Swiss federal statutory rate	(33)	59	78
Changes in unrecognized tax benefits, net	(62)	(179)	40
Change in valuation allowance	37	1	19
Benefit from foreign tax credits	(18)	(38)	(28)
Taxes on asset acquisition costs at rates lower than the Swiss federal statutory rate	—	—	8

Other, net	5	(6)	3
Income tax expense	$ 258	$ 50	$ 324

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

	December 31, 2013	December 31, 2012
Deferred tax assets		
Net operating loss carryforwards	$ 369	$ 380
Tax credit carryforwards	21	41
Accrued payroll expenses not currently deductible	98	95
Deferred income	62	86
Valuation allowance	(247)	(210)
Loss contingencies	36	—
Professional fees	89	66
Other	28	43
Total deferred tax assets	456	501
Deferred tax liabilities		
Depreciation and amortization	(650)	(688)
Other	(29)	(37)
Total deferred tax liabilities	(679)	(725)
Net deferred tax liabilities	$ (223)	$ (224)

At December 31, 2013 and 2012, our deferred tax assets include U.S. foreign tax credit carryforwards of $21 million and $41 million, respectively, which will expire between 2018 and 2023. The deferred tax assets related to our net operating losses were generated in various worldwide tax jurisdictions. At December 31, 2013, the tax effect of our Norwegian and Brazilian net operating losses, which do not expire, was $161 million and $49 million, respectively. At December 31, 2012, the tax effect of our Norwegian and Brazilian net operating losses, which do not expire, was $178 million and $55 million, respectively.

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

	December 31, 2013	December 31, 2012
Valuation allowance for non-current deferred tax assets	$ 247	$ 210

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

We consider the earnings of certain of our subsidiaries to be indefinitely reinvested. As such, we have not provided for taxes on these unremitted earnings. Should we make a distribution from the unremitted earnings of these subsidiaries, we would be subject to taxes payable to various jurisdictions. At December 31, 2013, the amount of indefinitely reinvested earnings was approximately $2.5 billion. If all of these indefinitely reinvested earnings were distributed, we would be subject to estimated taxes of $180 million to $250 million.

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

	Years ended December 31,		
	2013	2012	2011
Balance, beginning of period	$ 382	$ 515	$ 485
Additions for current year tax positions	24	58	45
Additions for prior year tax positions	10	25	29
Reductions for prior year tax positions	(72)	(24)	—
Settlements	(6)	(120)	(42)
Reductions related to statute of limitation expirations	(12)	(72)	(2)
Balance, end of period	$ 326	$ 382	$ 515

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

	December 31,	
	2013	2012
Unrecognized tax benefits, excluding interest and penalties	$ 326	$ 382
Interest and penalties	176	199
Unrecognized tax benefits, including interest and penalties	$ 502	$ 581

In the years ended December 31, 2013, 2012 and 2011, we recognized interest and penalties of $23 million, $56 million and $20 million, respectively, associated with our unrecognized tax benefits and recorded as a component of income tax expense. As of December 31, 2013, if recognized, $502 million of our unrecognized tax benefits, including interest and penalties, would favorably impact our effective tax rate.

It is reasonably possible that our existing liabilities for unrecognized tax benefits may increase or decrease in the year ending December 31, 2014, primarily due to the progression of open audits and the expiration of statutes of limitation. However, we cannot reasonably estimate a range of potential changes in our existing liabilities for unrecognized tax benefits due to various uncertainties, such as the unresolved nature of various audits.

Tax returns—We file federal and local tax returns in several jurisdictions throughout the world. With few exceptions, we are no longer subject to examinations of our U.S. and non-U.S. tax matters for years prior to 2006.

Our tax returns in the major jurisdictions in which we operate, other than Norway and Brazil, which are mentioned below, are generally subject to examination for periods ranging from three to six years. We have agreed to extensions beyond the statute of limitations in two major jurisdictions for up to 19 years. Tax authorities in certain jurisdictions are examining our tax returns and in some cases have issued assessments. We are defending our tax positions in those jurisdictions. While we cannot predict or provide assurance as to the 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 statement of cash flows.

Norway tax investigations and trial—Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 1999, 2001 and 2002 as well as the actions of certain employees of our former external tax advisors on these transactions. The authorities issued tax assessments as follows: (a) NOK 684 million, equivalent to approximately $112 million, plus interest, related to the migration of our subsidiary that was previously subject to tax in Norway, (b) NOK 412 million, equivalent to approximately $68 million, plus interest, related to a 2001 dividend payment and (c) NOK 43 million, equivalent to approximately $7 million, plus interest, related to certain foreign exchange deductions and dividend withholding tax. We have provided a parent company guarantee in the amount of approximately $115 million with respect to one of these tax disputes. Furthermore, we may be required to provide some form of additional financial security, in an amount up to $212 million, including interest and penalties, for other assessed amounts as these disputes are appealed and addressed by the Norwegian courts. The authorities are seeking penalties of 60 percent on most but not all matters. In November 2012, the Norwegian district court in Oslo heard the case regarding the disputed tax assessment of NOK 684 million related to the migration of our subsidiary. On March 1, 2013, the Norwegian district court in Oslo overturned the tax assessment and ruled in our favor, and the tax authorities have filed an appeal. We believe that our Norwegian tax returns are materially correct as filed, and we intend to continue to vigorously defend ourselves against all claims to the contrary.

In June 2011, the Norwegian authorities issued criminal indictments against two of our subsidiaries alleging misleading or incomplete disclosures in Norwegian tax returns for the years 1999 through 2002, as well as inaccuracies in Norwegian statutory financial statements for the years ended December 31, 1996 through 2001. The criminal trial commenced in December 2012. Two employees of our former external tax advisors were also issued criminal indictments with respect to the disclosures in our tax returns, and our former external Norwegian tax attorney was issued criminal indictments related to certain of our restructuring transactions and the 2001 dividend payment. We believe the charges brought against us are without merit and do not alter our technical assessment of the underlying claims. In January 2012, the Norwegian authorities supplemented the previously issued criminal indictments by issuing a financial claim of NOK 1.8 billion, equivalent to approximately $302 million, jointly and severally, against our two subsidiaries, the two external tax advisors and the external tax attorney. In February 2012, the authorities dropped the previously existing civil tax claim related to a certain restructuring transaction. In April 2012, the Norwegian tax authorities supplemented the previously issued criminal indictments against our two subsidiaries by extending a criminal indictment against a third subsidiary, alleging misleading or incomplete disclosures in Norwegian tax returns for the years 2001 and 2002. In May 2013, the Norwegian authorities dropped the financial claim of NOK 1.8 billion against one of our subsidiaries and the criminal case related to the migration case of another subsidiary. The criminal trial proceedings ended in September 2013, and the court has not yet ruled on the criminal issues. If we are found guilty, the Norwegian authorities have asked the court to assess criminal penalties in the amount of $38 million against three of our subsidiaries in addition to any civil tax penalties and the financial claim. We believe our Norwegian tax returns are materially correct as filed, and we intend to continue to vigorously contest any assertions to the contrary by the Norwegian civil and criminal authorities in connection with the various transactions being investigated. An unfavorable outcome on the Norwegian civil or criminal tax matters could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Brazil tax investigations—Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. In December 2005, the Brazilian tax authorities issued an aggregate tax assessment of BRL 677 million, equivalent to $283 million, including a 75 percent penalty and interest through December 31, 2013. On January 25, 2008, we filed a protest letter with the Brazilian tax authorities, and we are currently engaged in the appeals process. We believe our returns are materially correct as filed, and we are vigorously contesting these assessments. An unfavorable outcome on these proposed assessments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other tax matters—We conduct operations through our various subsidiaries in a number of countries throughout the world. Each country has its own tax regimes with varying nominal rates, deductions 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. See Note 27—Subsequent Events.

Note 7—Discontinued Operations

Summarized results of discontinued operations

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

	Years ended December 31,		
	2013	2012	2011
Operating revenues	$ 796	$ 1,055	$ 1,171
Operating and maintenance expense	(800)	(990)	(871)
Depreciation and amortization expense	—	(183)	(342)
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, net	5	—	18
Income (loss) from discontinued operations before income tax expense	41	(1,022)	121
Income tax expense	(40)	(5)	(36)
Income (loss) from discontinued operations, net of tax	$ 1	$ (1,027)	$ 85

Assets and liabilities of discontinued operations

The carrying amounts of the major classes of assets and liabilities associated with our discontinued operations were classified as follows (in millions):

	December 31, 2013	December 31, 2012
Assets		
Rigs and related equipment, net	$ —	$ 104
Materials and supplies, net	18	71
Other related assets	1	4
Assets held for sale	$ 19	$ 179
Liabilities		
Deferred revenues	$ 8	$ 32
Other liabilities	—	3
Other current liabilities	$ 8	$ 35

Standard jackup and swamp barge contract drilling services

Overview—In September 2012, in connection with our efforts to dispose of non-strategic assets and to reduce our exposure to low-specification drilling units, we committed to a plan to discontinue operations associated with the standard jackup and swamp barge asset groups, components of our contract drilling services operating segment. As a result, we allocated $112 million of goodwill to this disposal group based on the fair value of the disposal group relative to the fair value of the contract drilling services operating segment. We estimated the fair values of the disposal group and the contract drilling services operating segment by applying a variety of valuation methods, incorporating the income and market approaches, and using significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the disposal group and of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rig utilization and dayrates.

At December 31, 2012, we had seven standard jackups, including D.R. Stewart, GSF Adriatic VIII, GSF Rig 127, GSF Rig 134, Interocean III, Trident IV-A and Trident VI, along with related equipment, which were classified as assets held for sale with an aggregate carrying amount of $112 million, including $8 million in materials and supplies. In the year ended December 31, 2013, we completed the sales of these standard jackups and related equipment.

Impairments—In the year ended December 31, 2013, we recognized an aggregate loss of $14 million ($0.04 per diluted share), which had no tax effect, associated with the impairment of standard jackups GSF Rig 127 and GSF Rig 134. In the year ended December 31, 2012, we also recognized an aggregate loss of $29 million ($0.08 per diluted share), which had no tax effect, associated with the impairment of the standard jackups GSF Adriatic II and GSF Rig 136. In the year ended December 31, 2011, we recognized an aggregate loss of $28 million ($0.09 per diluted share), which had a tax effect of less than $1 million, associated with the impairment of the standard jackups George H. Galloway, GSF Britannia, GSF Labrador and the swamp barge Searex IV. We measured the impairment of the drilling units and related equipment as the amount by which the carrying amounts exceeded the estimated fair values less costs to sell. We estimated the fair value of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including a binding sale and purchase agreement for the drilling units and related equipment.

In September 2012, in connection with our reclassification of the standard jackup and swamp barge disposal group to assets held for sale, we determined that the disposal group was impaired since its aggregate carrying amount exceeded its aggregate fair value. We estimated the fair value of this disposal group by applying a variety of valuation methods, incorporating cost, income and market approaches, to estimate the exit price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. Although we based certain components of our valuation on significant other observable inputs, including binding sale and purchase agreements, a significant portion of our valuation required us to project the future performance of the disposal group based on significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions regarding long-term projections for future revenues and costs, dayrates, rig utilization rates and revenue efficiency rates. We measured the impairments of the disposal group as the amount by which its carrying amount exceeded its estimated fair value less costs to sell. We included in our estimated loss on impairment as a reduction to the expected proceeds approximately $60 million of costs for certain shipyard projects and other obligations required pursuant to the sale agreement and approximately $17 million of costs to sell the disposal group, including legal and financial advisory costs and expenses. In the year ended December 31, 2012, as a result of our valuation, we recognized losses of $744 million ($2.09 per diluted share) and $112 million ($0.31 per diluted share), which had no tax effect, associated with the impairment of long-lived assets and the goodwill, respectively.

In connection with our sale transactions with Shelf Drilling, we were, and continue to be, required to pay postemployment benefits to certain employees and contract labor for which employment was or will be terminated as a direct result of the sale transactions upon expiration of the operating agreements and transition services agreement. In the year ended December 31, 2012, we recognized a loss of $20 million, included in loss on impairment of assets in discontinued operations, associated with such postemployment benefits.

Sale transactions with Shelf Drilling—On November 30, 2012, we completed the sale of 38 drilling units, along with related equipment, to Shelf Drilling. In connection with the sale, we received cash proceeds of $568 million, net of certain working capital and other adjustments, and non-cash proceeds in the form of perpetual preference shares that had a stated value of $195 million and an estimated fair value of $194 million, including the fair value associated with embedded derivatives, estimated at the time of the closing of the sale transactions. In June 2013, we sold the preference shares to an unaffiliated party for cash proceeds of $185 million and, in the year ended December 31, 2013, we recognized a loss of $10 million ($0.03 per diluted share), recorded in other expense, net, which had no tax effect, associated with the sale of the preference shares.

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

Under the operating agreements, we agreed to continue to operate these standard jackups on behalf of Shelf Drilling for periods ranging from nine months to 27 months, until expiration or novation of the underlying drilling contracts by Shelf Drilling, and under a transition services agreement, we agreed to provide certain transition services for a period of up to 18 months following the completion of the sale transactions. As of December 31, 2013, we operated seven standard jackups under operating agreements with Shelf Drilling. Until the expiration or novation of such drilling contracts, we retain possession of the materials and supplies associated with the standard jackups that we operate under the operating agreements. In the years ended December 31, 2013 and 2012, we received cash proceeds of $64 million and $30 million and recognized aggregate gains of $11 million ($0.03 per diluted share), which had no tax effect, and $8 million (net loss of $5 million or $0.01 per diluted share, net of tax), respectively, associated with the sale of equipment and materials and supplies to Shelf Drilling upon expiration of novation of the drilling contracts. At December 31, 2013 and 2012, the materials and supplies associated with the drilling units that we operated under operating agreements with Shelf Drilling had an aggregate carrying amount of $18 million and $63 million, respectively.

For a period of up to three years following the closing of the sale transactions, we have agreed to provide to Shelf Drilling up to $125 million of financial support by maintaining letters of credit, surety bonds and guarantees for various contract bidding and performance activities associated with the drilling units sold to Shelf Drilling and in effect at the closing of the sale transactions. At the time of the sale transactions, we had $113 million of outstanding letters of credit, issued under our committed and uncommitted credit lines, in support of rigs sold to Shelf Drilling. Included within the $125 million maximum amount, we agreed to provide up to $65 million of additional financial support in connection with any new drilling contracts related to such drilling units. Shelf Drilling is required to reimburse us in the event that any of these instruments are called. At December 31, 2013 and 2012, we had $104 million and $113 million, respectively, of outstanding letters of credit, issued under our committed and uncommitted credit lines, in support of drilling units sold to Shelf Drilling. See Note 15—Commitments and Contingencies.

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

During the year ended December 31, 2012, we also completed the sales of the standard jackups GSF Adriatic II, GSFRig 103, GSFRig 136, Roger W. Mowell, Transocean Nordic, Transocean Shelf Explorer and Trident 17, along with related equipment. In the year ended December 31, 2012, in connection with the disposal of these assets, we received aggregate net cash proceeds of $198 million and recognized an aggregate net gain of $74 million ($0.20 per diluted share), which had no tax effect. In the year ended December 31, 2012, we recognized an aggregate net loss of $9 million associated with the disposal of assets unrelated to dispositions of rigs.

During the year ended December 31, 2011, we completed the sales of the standard jackups George H. Galloway, GSF Adriatic XI, GSF Britannia, GSF Labrador and Transocean Mercury and the swamp barge Searex IV, along with related equipment, and our ownership interest in Joides Resolution. In connection with the disposal of these assets, in the year ended December 31, 2011, we received aggregate net cash proceeds of $187 million and recognized an aggregate net gain of $32 million ($0.10 per diluted share), which had no tax effect. In the year ended December 31, 2011, we recognized an aggregate net loss of $1 million associated with the disposal of assets unrelated to dispositions of rigs.

Caspian Sea contract drilling services

Overview—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. 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.

Disposition—In the year ended December 31, 2011, in connection with the sale of the High-Specification Jackup Trident 20, we received net cash proceeds of $259 million and recognized a net gain of $169 million ($0.52 per diluted share), which had no tax effect.

U.S. Gulf of Mexico drilling management services

Overview—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. We based our decision to abandon this market on the declining market outlook for these services in the shallow waters of the U.S. Gulf of Mexico as well as the more difficult regulatory environment for obtaining drilling permits. In December 2012, we completed the final drilling management project and discontinued offering our drilling management services in this region.

Impairments—During the year ended December 31, 2012, we determined that the customer relationships intangible asset and the trade name intangible asset associated with the U.S. operations of our drilling management services reporting unit was impaired due to the declining market outlook for these services in the shallow waters of the U.S. Gulf of Mexico as well as the increasingly difficult regulatory environment for obtaining drilling permits and the diminishing demand for our drilling management services. We estimated the fair value of the customer relationships intangible asset using the multiperiod excess earnings method, a valuation methodology that applies the income approach. We estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the drilling management services reporting unit, such as future commodity prices, projected demand for our services, rig utilization and dayrates. We estimated the fair value of the trade name intangible asset using the relief from royalty method, a valuation methodology that applies the income approach. We estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the drilling management services reporting unit, such as future commodity prices, projected demand for drilling management services, rig utilization and dayrates. In the year ended December 31, 2012, as a result of our valuations, we determined that the carrying amounts of these intangible assets exceeded their respective fair values, and we recognized losses of $31 million ($20 million or $0.06 per diluted share, net of tax) and $39 million ($25 million or $0.07 per diluted share, net of tax) associated with the impairment of the customer relationships intangible asset and the trade name intangible asset, respectively.

See Note 27—Subsequent Events.

Oil and gas properties

Overview—In March 2011, in connection with our efforts to dispose of non-strategic assets, we engaged an unaffiliated advisor to coordinate the sale of the assets of our oil and gas properties reporting unit, formerly a component of our other operations segment, which comprised the exploration, development and production activities performed by CMI. During the year ended December 31, 2012, we completed the sale of these assets.

Impairments—In the years ended December 31, 2012 and 2011, we recognized losses of $11 million ($10 million or $0.02 per diluted share, net of tax) and $10 million ($6 million or $0.02 per diluted share, net of tax), respectively, associated with the impairment of our oil and gas properties, which were classified as assets held for sale at the time of impairment, since the carrying amount of the properties exceeded the estimated fair value less costs to sell the properties.

Dispositions—During the year ended December 31, 2012, we completed the sales of the assets of Challenger Minerals Inc. and Challenger Minerals (Ghana) Limited for aggregate net cash proceeds of $13 million, which had no tax effect. During the year ended December 31, 2011, we completed the sale of Challenger Minerals (North Sea) Limited for aggregate net cash proceeds of $24 million, and in May 2012, we received additional cash proceeds of

$10 million. In the years ended December 31, 2012 and 2011, we recognized an aggregate net gain of $9 million ($0.02 per diluted share), which had no tax effect, and an aggregate net loss of $4 million (aggregate net gain of $14 million or $0.05 per diluted share, net of tax), respectively, associated with the completion of these sales.

Note 8—Earnings (Loss) Per Share

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

	Years ended December 31,					
	2013		2012		2011	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
Numerator for earnings (loss) per share						
Income (loss) from continuing operations attributable to controlling interest	$ 1,406	$ 1,406	$ 808	$ 808	$ (5,839)	$ (5,839)
Undistributed earnings allocable to participating securities	(12)	(12)	—	—	—	—
Income (loss) from continuing operations available to shareholders	$ 1,394	$ 1,394	$ 808	$ 808	$ (5,839)	$ (5,839)
Denominator for earnings (loss) per share						
Weighted-average shares outstanding	360	360	356	356	322	322
Effect of stock options and other share-based awards	—	—	—	—	—	—
Weighted-average shares for per share calculation	360	360	356	356	322	322
Per share earnings (loss) from continuing operations	$ 3.87	$ 3.87	$ 2.27	$ 2.27	$ (18.14)	$ (18.14)

For the years ended December 31, 2013, 2012 and 2011, we excluded 1.4 million, 2.4 million and 2.4 million share-based awards, respectively, from the calculation since the effect would have been anti-dilutive. The 1.50% Series B Convertible Senior Notes and the 1.50% Series C Convertible Senior Notes did not have an effect on the calculation for the periods presented. See Note 12—Debt.

Note 9—Other Comprehensive Income (Loss)

The allocation of other comprehensive income (loss) attributable to controlling interest and to noncontrolling interest was as follows (in millions):

	Years ended December 31,								
	2013			2012			2011		
	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	T
r orehensive me (loss) e ssifications									
ponents of eriodic fit costs	$ 198	$ —	$ 198	$ (52)	$ —	$ (52)	$ (204)	$ —	$ (
(loss) on ative uments	(5)	—	(5)	6	(3)	3	3	(16)	
on etable ities	—	—	—	—	—	—	(13)	—	
assifications t income									
ponents of eriodic fit costs	49	—	49	47	—	47	25	—	
) loss on ative uments	15	3	18	(4)	3	(1)	(1)	12	
on etable ities	—	—	—	2	—	2	13	—	
r orehensive me (loss) e income	257	3	260	(1)	—	(1)	(177)	(4)	(
me taxes ed to other orehensive me (loss)	2	—	2	(7)	—	(7)	13	—	
r orehensive me (loss), f income	$ 259	$ 3	$ 262	$ (8)	$ —	$ (8)	$ (164)	$ (4)	$ (

(a) Includes amounts attributable to noncontrolling interest and redeemable noncontrolling interest.

Note 10—Drilling Fleet

Construction work in progress—For each of the three years ended December 31, 2013, the changes in our construction work in progress, including capital expenditures and other capital additions, such as capitalized interest, were as follows (in millions):

	Years ended December 31,		
	2013	2012	2011
Construction work in progress, at beginning of period	$ 2,010	$ 1,391	$ 1,459
Newbuild construction program			
Deepwater Champion (a) (b)	—	—	76
Transocean Honor (a) (c)	—	35	129
Transocean Siam Driller (a) (d)	74	39	113
Transocean Andaman (a) (d)	82	38	113
Transocean Ao Thai (a) (d)	90	72	80
Deepwater Asgard (e)	309	46	4
Deepwater Invictus (e)	65	40	3
Deepwater Thalassa (f)	154	139	—
Deepwater Proteus (f)	146	128	—
Deepwater Pontus (f)	65	76	—
Deepwater Poseidon (f)	66	76	—
Deepwater Conqueror (g)	108	—	—
High-Specification Jackup TBN1 (h)	44	—	—
High-Specification Jackup TBN2 (h)	44	—	—
High-Specification Jackup TBN3 (h)	44	—	—
High-Specification Jackup TBN4 (h)	44	—	—
High-Specification Jackup TBN5 (h)	44	—	—
Other construction projects and capital additions	859	614	456
Total capital expenditures	2,238	1,303	974
Changes in accrued capital expenditures	44	61	(2)
Acquisition of construction work in progress (e)	—	—	272
Impairment of certain corporate assets under construction	(17)	—	—
Property and equipment placed into service			
Deepwater Champion (b)	—	—	(881)
Transocean Honor (c)	—	(262)	—
Transocean Siam Driller (a) (d)	(236)	—	—
Transocean Andaman (a) (d)	(242)	—	—
Transocean Ao Thai (a) (d)	(242)	—	—
Other property and equipment	(845)	(483)	(431)
Construction work in progress, at end of period	$ 2,710	$ 2,010	$ 1,391

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

(b) The Ultra-Deepwater Floater Deepwater Champion commenced operations in May 2011.

(c) The High-Specification Jackup Transocean Honor, owned through our 70 percent interest in TDSOI, commenced operations in May 2012. The costs presented above represent 100 percent of TDSOI's expenditures in the construction of Transocean Honor.

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

(e) 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. In the year ended December 31, 2011, in connection with our acquisition of Aker Drilling ASA ("Aker Drilling"), we acquired construction work in progress with an aggregate estimated fair value of $272 million.

(f) 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.

(g) 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.

(h) 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.

Dispositions—During the year ended December 31, 2013, in connection with our efforts to dispose of non-strategic assets, we committed to plans to sell the Deepwater Floaters Sedco 709 and Transocean Richardson, the Midwater Floaters C. Kirk Rhein, Jr., Falcon 100 and Sedco 703 and the High-Specification Jackup GSF Monitor. During the year ended December 31, 2013, we completed the sale of Transocean Richardson along with related equipment, and as a result of the sale, we received net cash proceeds of $142 million and recognized a net gain of $33 million ($22 million or $0.06 per diluted share, net of tax). In the year ended December 31, 2013, we received cash proceeds of $32 million and recognized an aggregate net loss of $26 million associated with the disposal of assets unrelated to dispositions of rigs. At December 31, 2013, in addition to the remaining assets of our discontinued operations, our assets held for sale included Sedco 709, C. Kirk Rhein, Jr., Falcon 100, Sedco 703 and GSF Monitor, along with related equipment, with an aggregate carrying amount of $129 million. See Note 5—Impairments.

During the year ended December 31, 2012, in connection with our efforts to dispose of non-strategic assets, we completed the sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham. In connection with these sales, we received aggregate net cash proceeds of $178 million and recognized an aggregate net gain of $51 million ($48 million or $0.13 per diluted share, net of tax). In the year ended December 31, 2012, we recognized an aggregate net loss of $15 million associated with the disposal of assets unrelated to dispositions of rigs.

In the year ended December 31, 2011, we recognized an aggregate net loss of $12 million associated with the disposal of assets unrelated to dispositions of rigs.

Note 11—Goodwill and Other Intangible Assets

Goodwill—The gross carrying amounts of goodwill and accumulated impairment associated with our contract drilling services reporting unit were as follows (in millions):

	Year ended December 31, 2013			Year ended December 31, 2012		
	Gross carrying amount	Accumulated impairment	Net carrying amount	Gross carrying amount	Accumulated impairment	Net carrying amount
Balance, beginning of period	$ 10,799	$ (7,812)	$ 2,987	$ 10,911	$ (7,694)	$ 3,217
Impairment associated with continuing operations	—	—	—	—	(118)	(118)
Reclassified balance associated with discontinued operations (a)	—	—	—	(112)	—	(112)
Balance, end of period	$ 10,799	$ (7,812)	$ 2,987	$ 10,799	$ (7,812)	$ 2,987

(a) As a result of our decision to discontinue operations associated with the standard jackups and swamp barge asset groups, components of our contract drilling services operating segment, we allocated $112 million of goodwill attributable to such operations, which was subsequently impaired. See Note 7—Discontinued Operations.

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Definite-lived intangible assets and liabilities—The gross carrying amounts of our drilling contract intangibles and drilling management customer relationships, both of which we consider to be definite-lived intangible assets and intangible liabilities, and accumulated amortization and impairment were as follows (in millions):

	Year ended December 31, 2013			Year ended December 31, 2012		
	Gross carrying amount	Accumulated amortization and impairment	Net carrying amount	Gross carrying amount	Accumulated amortization and impairment	Net carrying amount
Drilling contract intangible assets						
Balance, beginning of period	$ 9	(9)	—	$ 191	$ (191)	$ —
Amortization	—	—	—	—	—	—
Reclassified balance associated with discontinued operations (a)	—	—	—	(182)	182	—
Balance, end of period	9	(9)	—	9	(9)	—
Customer relationships						
Balance, beginning of period	60	(60)	—	148	(94)	54
Amortization	—	—	—	—	(1)	(1)
Impairment associated with continuing operations	—	—	—	—	(22)	(22)
Reclassified balance associated with discontinued operations (b)	—	—	—	(88)	57	(31)
Balance, end of period	60	(60)	—	60	(60)	—
Total definite-lived intangible assets						
Balance, beginning of period	69	(69)	—	339	(285)	54
Amortization	—	—	—	—	(1)	(1)
Impairment associated with continuing operations	—	—	—	—	(22)	(22)
Reclassified balance associated with discontinued	—	—	—	(270)	239	(31)

operations (b)						
Balance, end of period	$ 69	(69)	—	$ 69	$ (69)	$ —
Drilling contract intangible liabilities						
Balance, beginning of period	$ 1,410	$ (1,351)	$ 59	$ 1,494	$ (1,393)	$ 101
Amortization	—	(15)	(15)	—	(42)	(42)
Reclassified balance associated with discontinued operations (a)	—	—	—	(84)	84	—
Balance, end of period	$ 1,410	$ (1,366)	$ 44	$ 1,410	$ (1,351)	$ 59

(a) As a result of our decision to discontinue operations associated with the standard jackup and swamp barge asset groups, we reclassified the balances attributable to such operations. See Note 7—Discontinued Operations.

(b) As a result of our decision to discontinue the U.S. operations of our drilling management services operating segment, we reclassified the balances attributable to such operations. See Note 7—Discontinued Operations.

At December 31, 2013, the estimated future amortization of our drilling contract intangible liabilities was as follows (in millions):

	Drilling contract intangible liabilities
Years ending December 31,	
2014	$ 15
2015	15
2016	14
Total intangible liabilities	$ 44

Note 12—Debt

Debt, net of unamortized discounts, premiums and fair value adjustments, was comprised of the following (in millions):

	December 31, 2013			December 31, 2012		
	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
5% Notes due February 2013	$ —	$ —	$ —	$ 250	$ —	$ 250
5.25% Senior Notes due March 2013 (a)	—	—	—	502	—	502
TPDI Credit Facilities due March 2015	—	—	—	403	—	403
4.95% Senior Notes due November 2015 (a)	1,113	—	1,113	1,118	—	1,118
Callable Bonds due February 2016	—	—	—	282	—	282
5.05% Senior Notes due December 2016 (a)	999	—	999	999	—	999
2.5% Senior Notes due October 2017 (a)	748	—	748	748	—	748
ADDCL Credit Facilities due December 2017	—	163	163	—	191	191
Eksportfinans Loans due January 2018	591	—	591	797	—	797
6.00% Senior Notes due March 2018 (a)	998	—	998	998	—	998
7.375% Senior Notes due April 2018 (a)	247	—	247	247	—	247
6.50% Senior Notes due November 2020 (a)	900	—	900	899	—	899
6.375% Senior Notes due December 2021 (a)	1,199	—	1,199	1,199	—	1,199
3.8% Senior Notes due October 2022 (a)	745	—	745	745	—	745
7.45% Notes due April 2027 (a)	97	—	97	97	—	97
	57	—	57	57	—	57

8% Debentures due April 2027 (a)						
7% Notes due June 2028	311	—	311	311	—	311
Capital lease contract due August 2029	637	—	637	657	—	657
7.5% Notes due April 2031 (a)	598	—	598	598	—	598
1.50% Series C Convertible Senior Notes due December 2037 (a)	—	—	—	62	—	62
6.80% Senior Notes due March 2038 (a)	999	—	999	999	—	999
7.35% Senior Notes due December 2041 (a)	300	—	300	300	—	300
Total debt	10,539	163	10,702	12,268	191	12,459
Less debt due within one year						
5% Notes due February 2013	—	—	—	250	—	250
5.25% Senior Notes due March 2013 (a)	—	—	—	502	—	502
TPDI Credit Facilities due March 2015	—	—	—	70	—	70
Callable Bonds due February 2016	—	—	—	282	—	282
ADDCL Credit Facilities due December 2017	—	163	163	—	28	28
Eksportfinans Loans due January 2018	140	—	140	153	—	153
Capital lease contract due August 2029	20	—	20	20	—	20
1.50% Series C Convertible Senior Notes due December 2037 (a)	—	—	—	62	—	62
Total debt due within one year	160	163	323	1,339	28	1,367
Total long-term debt	$ 10,379	$ —	$ 10,379	$ 10,929	$ 163	$ 11,092

(a) Transocean Inc., a 100 percent owned subsidiary of Transocean Ltd., is the issuer of the notes and debentures, which have been guaranteed by Transocean Ltd. Transocean Ltd. has also guaranteed borrowings under the Five-Year Revolving Credit Facility and the Three-Year Secured Revolving Credit Facility. Transocean Ltd. and Transocean Inc. are not subject to any significant restrictions on their ability to obtain funds from their consolidated subsidiaries by dividends, loans or return of capital distributions. See Note 24—Condensed Consolidating Financial Information.

Scheduled maturities—At December 31, 2013, the scheduled maturities of our debt were as follows (in millions):

	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
Years ending December 31,			
2014	$ 160	$ 163	$ 323
2015	1,263	—	1,263
2016	1,165	—	1,165
2017	917	—	917
2018	1,311	—	1,311
Thereafter	5,719	—	5,719
Total debt, excluding unamortized discounts, premiums and fair value adjustments	10,535	163	10,698
Total unamortized discounts, premiums and fair value adjustments, net	4	—	4
Total debt	$ 10,539	$ 163	$ 10,702

Five-Year Revolving Credit Facility—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 may borrow under the Five-Year Revolving Credit Facility at either (1) the adjusted London Interbank Offered Rate ("LIBOR") plus a margin (the "Five-Year Revolving Credit Facility Margin") that is based on the credit rating of our non-credit enhanced senior unsecured long-term debt ("Debt Rating") or (2) the base rate specified in the credit agreement plus the Five-Year Revolving Credit Facility Margin, less one percent per annum. At December 31, 2013, based on our Debt Rating on that date, the Five-Year Revolving Credit Facility Margin was 1.625 percent. Throughout the term of the Five-Year Revolving Credit Facility, we pay a facility fee on the daily unused amount of the underlying commitment, which ranges from 0.125 percent to 0.325 percent depending on our Debt Rating, and was 0.275 percent at December 31, 2013. Among other things, the Five-Year Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Five-Year Revolving Credit Facility also includes a covenant imposing a maximum debt to tangible capitalization ratio of 0.6 to 1.0. Borrowings under the Five-Year Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default. Borrowings are guaranteed by Transocean Ltd. and may be prepaid in whole or in part without premium or penalty. At December 31, 2013, we had $20 million in letters of credit issued and outstanding, we had no borrowings outstanding, and we had $2.0 billion of available borrowing capacity under the Five-Year Revolving Credit Facility.

Three-Year Secured Revolving Credit Facility—We 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"). We may borrow under the Three-Year Secured Revolving Credit Facility at either (1) LIBOR plus a margin (the "Three-Year Secured Revolving Credit Facility Margin") that ranges from 0.875 percent to 2.5 percent based on our Debt Rating or (2) the base rate specified in the credit agreement plus the Three-Year Secured Revolving Credit Facility Margin, less one percent per annum. At December 31, 2013, based on our Debt Rating on that date, the Three-Year Secured Revolving Credit Facility Margin was 2.0 percent. Throughout the term of the Three-Year Secured Revolving Credit Facility, we pay a facility fee on the daily unused amount of the underlying commitment, which ranges from 0.125 percent to 0.50 percent depending on our Debt Rating, and was 0.375 percent at December 31, 2013. Among other things, the Three-Year Secured Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Three-Year Secured Revolving Credit Facility also contains a covenant imposing a maximum debt to tangible capitalization ratio of 0.6 to 1.0. Borrowings under the Three-Year Secured Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default. Borrowings are guaranteed by Transocean Ltd. and Transocean Inc. and may be prepaid in whole or in part without premium or penalty. At December 31, 2013, we had no borrowings outstanding, and we had $900 million of available borrowing capacity under the Three-Year Secured Revolving Credit Facility.

Borrowings under the Three-Year Secured Revolving Credit Facility are secured by the Ultra-Deepwater Floaters Deepwater Champion, Discoverer Americas and Discoverer Inspiration. At December 31, 2013 and 2012, the aggregate carrying amount of Deepwater Champion, Discoverer Americas and Discoverer Inspiration was $2.2 billion and $2.3 billion, respectively.

5% Notes and 7% Notes—Two of our wholly-owned subsidiaries are the obligors on the 5% Notes due 2013 (the “5% Notes”) and the 7% Notes due 2028 (the “7% Notes”), and we have not guaranteed either obligation. The indentures related to the 5% Notes and the 7% Notes contain limitations on creating liens and sale/leaseback transactions. The respective obligor may redeem the 5% Notes and the 7% Notes in whole or in part at a price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make-whole premium.

On February 15, 2013, we repaid the outstanding $250 million aggregate principal amount of the 5% Notes due February 2013 as of the stated maturity date. At December 31, 2013, the aggregate outstanding principal amount of the 7% Notes was $300 million.

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

On March 15, 2013, we repaid the outstanding $500 million aggregate principal amount of the 5.25% Senior Notes due March 2013 as of the stated maturity date. At December 31, 2013, the aggregate outstanding principal amount of the 6.00% Senior Notes and the 6.80% Senior Notes was $1.0 billion each.

TPDI Credit Facilities—Through our wholly owned subsidiary, Transocean Pacific Drilling Inc. ("TPDI"), 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 dated October 28, 2008, that was scheduled to expire in March 2015 (the "TPDI Credit Facilities"). One of our subsidiaries participated in the senior and junior term loans with an aggregate commitment of $595 million.

Under the TPDI Credit Facilities, we were required to satisfy certain liquidity requirements, including a requirement to maintain certain cash balances in restricted accounts for the payment of scheduled installments. At December 31, 2012, we had restricted cash investments of $23 million. At December 31, 2012, we had an outstanding letter of credit in the amount of $60 million to satisfy additional liquidity requirements under the TPDI Credit Facilities.

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 and the related security agreement with respect to the Ultra-Deepwater Floaters Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2. In the year ended December 31, 2013, we recognized a loss of $1 million associated with the retirement of debt.

4.95% Senior Notes and 6.50% Senior Notes—In September 2010, we issued $1.1 billion aggregate principal amount of 4.95% Senior Notes due November 2015 (the "4.95% Senior Notes") and $900 million aggregate principal amount of 6.50% Senior Notes due November 2020 (the "6.50% Senior Notes," and together with the 4.95% Senior Notes, the "2010 Senior Notes"). We are required to pay interest on the 2010 Senior Notes on May 15 and November 15 of each year, beginning November 15, 2010. We may redeem some or all of the 2010 Senior Notes at any time at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make-whole premium. The indenture pursuant to which the 2010 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. At December 31, 2013, the aggregate outstanding principal amount of the 4.95% Senior Notes and the 6.50% Senior Notes was $1.1 billion and $900 million, respectively.

5.05% Senior Notes, 6.375% Senior Notes and 7.35% Senior Notes—In December 2011, we issued $1.0 billion aggregate principal amount of 5.05% Senior Notes due December 2016 (the "5.05% Senior Notes"), $1.2 billion aggregate principal amount of 6.375% Senior Notes due December 2021 (the "6.375% Senior Notes") and $300 million aggregate principal amount of 7.35% Senior Notes due December 2041 (the "7.35% Senior Notes," and collectively with the 5.05% Senior Notes and the 6.375% Senior Notes, the "2011 Senior Notes"). The interest rates for the notes are subject to adjustment from time to time upon a change to our Debt Rating. The indenture pursuant to which the

2011 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. We may redeem some or all of the 2011 Senior Notes at any time at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, and a make-whole premium. At December 31, 2013, the aggregate outstanding principal amount of the 5.05% Senior Notes, the 6.375% Senior Notes and the 7.35% Senior Notes was $1.0 billion, $1.2 billion and $300 million, respectively.

Aker Revolving Credit and Term Loan Facility—We had a credit facility, comprised of a $500 million revolving credit facility and a $400 million term loan, established under the Revolving Credit and Term Loan Facility Agreement dated February 21, 2011 (the "Aker Revolving Credit and Term Loan Facility"). In the year ended December 31, 2012, we prepaid $333 million of borrowings outstanding under the Aker Term Loan, and we recognized a gain of $2 million associated with the retirement of debt. In September 2012, we cancelled the Aker Revolving Credit and Term Loan Facility.

Callable Bonds—We were the obligor for 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"), which were publicly traded on the Oslo Stock Exchange. 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. In the year ended December 31, 2013, we recognized a loss of $1 million associated with the retirement of debt.

2.5% Senior Notes and 3.8% Senior Notes—In September 2012, we issued $750 million aggregate principal amount of 2.5% Senior Notes due October 2017 (the "2.5% Senior Notes") and $750 million aggregate principal amount of 3.8% Senior Notes due October 2022 (the "3.8% Senior Notes," and together with the 2.5% Senior Notes, the "2012 Senior Notes"). The interest rates for the notes are subject to adjustment from time to time upon a change to our Debt Rating. The indenture pursuant to which the 2012 Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. We may redeem some or all of the 2012 Senior Notes at any time prior to maturity at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any, together with a make-whole premium unless, in the case of the 3.8% Senior Notes, such redemption occurs on or after July 15, 2022, in which case no such make-whole premium will apply. At December 31, 2013, the aggregate outstanding principal amount of the 2.5% Senior Notes and the 3.8% Senior Notes was $750 million each.

ADDCL Credit Facilities—ADDCL has a senior secured credit facility, comprised of Tranche A for $215 million and Tranche C for $399 million, under a bank credit agreement dated June 2, 2008 that is scheduled to expire in December 2017 (the "ADDCL Primary Loan Facility"). Unaffiliated financial institutions provide the commitment for and borrowings under Tranche A, and one of our subsidiaries provides the commitment for Tranche C. Tranche A bears interest at LIBOR plus the applicable margin of 0.725 percent. Tranche A requires semi-annual installments of principal and interest. The ADDCL Primary Loan Facility contains various covenants, including requirements that ADDCL maintain certain cash balances to service the debt and limit its ability to incur additional indebtedness, to acquire assets, or to make distributions or other payments. At December 31, 2013, $135 million was outstanding under Tranche A at a weighted-average interest rate of 0.89 percent. At December 31, 2013, $399 million was outstanding under Tranche C, which was eliminated in consolidation.

Borrowings under the ADDCL Primary Loan Facility are secured by the Ultra-Deepwater Floater Discoverer Luanda. At December 31, 2013 and 2012, the carrying amount of Discoverer Luanda was $748 million and $786 million, respectively.

ADDCL also has a $90 million secondary credit facility, established under a bank credit agreement dated June 2, 2008 that is 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 provides 65 percent of the total commitment under the ADDCL Secondary Loan Facility. The facility bears interest at LIBOR plus the applicable margin, ranging from 3.125 percent to 5.125 percent, depending on certain milestones. Borrowings under the ADDCL Secondary Loan Facility are subject to acceleration by the unaffiliated financial institution upon the occurrence of certain events of default, including if our Debt Rating falls below investment grade. The ADDCL Secondary Loan Facility is payable in full in December 2015, and it may be prepaid in whole or in part without premium or penalty. At December 31, 2013, $80 million was outstanding under the ADDCL Secondary Loan Facility, of which $52 million was provided by one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on December 31, 2013 was 3.3 percent.

ADDCL is required to maintain certain cash balances in restricted accounts for the payment of the scheduled installments on the ADDCL Credit Facilities. At December 31, 2013 and 2012, ADDCL had restricted cash investments of $20 million and $19 million, respectively. See Note 27—Subsequent Events.

Eksportfinans Loans—We have borrowings outstanding under the Loan Agreement dated September 12, 2008 ("Eksportfinans Loan A") and under the Loan Agreement dated November 18, 2008 ("Eksportfinans Loan B," and together with Eksportfinans Loan A, the "Eksportfinans Loans"). The Eksportfinans Loans bear interest at a fixed rate of 4.15 percent and require semi-annual installments of principal and interest through September 2017 and January 2018 for Eksportfinans Loan A and Eksportfinans Loan B, respectively. At December 31, 2013, $280 million and $314 million principal amount were outstanding under Eksportfinans Loan A and Eksportfinans Loan B, respectively.

The Eksportfinans Loans require cash collateral to remain on deposit at a financial institution through expiration (the "Eksportfinans Restricted Cash Investments"). The Eksportfinans Restricted Cash Investments bear interest at a fixed rate of 4.15 percent with semi-annual installments that correspond with those of the Eksportfinans Loans. At December 31, 2013 and 2012, the aggregate principal amount of the Eksportfinans Restricted Cash Investments was $594 million and $801 million, respectively.

7.375% Senior Notes—In March 2002, we issued $247 million principal amount of our 7.375% Senior Notes due April 2018 (the "7.375% Senior Notes"). The indenture pursuant to which the 7.375% Senior Notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. At December 31, 2013, the aggregate outstanding principal amount of the 7.375% Senior Notes was $247 million.

TPDI Notes—We previously issued promissory notes (the "TPDI Notes"), which were payable to our former partner and TPDI's former other shareholder with maturities through October 2019. On May 31, 2012, we extinguished the aggregate principal amount of $148 million and accrued and unpaid interest of $16 million associated with the TPDI Notes with a corresponding adjustment to additional paid-in capital. See Note 16—Redeemable Noncontrolling Interest.

7.45% Notes and 8% Debentures—In April 1997, a predecessor of Transocean Inc. issued $100 million aggregate principal amount of 7.45% Notes due April 2027 (the "7.45% Notes") and $200 million aggregate principal amount of 8% Debentures due April 2027 (the "8% Debentures"). The indenture pursuant to which the 7.45% Notes and the 8% Debentures were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. The 7.45% Notes and the 8% Debentures are redeemable at any time at our option subject to a make-whole premium. At December 31, 2013, the aggregate outstanding principal amount of the 7.45% Notes and the 8% Debentures was $100 million and $57 million, respectively.

Capital lease contract—In August 2009, we accepted delivery of Petrobras 10000, an asset held under capital lease, and we recorded $716 million to property and equipment, net and a corresponding increase to long-term debt. The capital lease contract has an implicit interest rate of 7.8 percent and requires scheduled monthly payments of $6 million through August 2029, after which we will have the right and obligation to acquire the drillship from the lessor for one dollar. See Note 15—Commitments and Contingencies.

7.5% Notes—In April 2001, we issued $600 million aggregate principal amount of 7.5% Notes due April 2031 (the "7.5% Notes"). The indenture pursuant to which the notes were issued contains restrictions on creating liens, engaging in sale/leaseback transactions and engaging in merger, consolidation or reorganization transactions. At December 31, 2013, the aggregate outstanding principal amount of the 7.5% Notes was $600 million.

1.50% Series B Convertible Senior Notes and 1.50% Series C Convertible Senior Notes—In December 2007, we issued $2.2 billion aggregate principal amount of 1.50% Series B Convertible Senior Notes due December 2037 (the "Series B Convertible Senior Notes") and $2.2 billion aggregate principal amount of 1.50% Series C Convertible Senior Notes due December 2037 (the "Series C Convertible Senior Notes" and, together with the Series B Convertible Series Notes, the "Convertible Senior Notes"). On December 14, 2012, holders of the Series C Convertible Senior Notes had the option to require us to repurchase all or any part of such holders' notes. As a result, we were required to repurchase an aggregate principal amount of $1.7 billion of the Series C Convertible Senior Notes for an aggregate cash payment of $1.7 billion.

In the years ended December 31, 2013, 2012 and 2011, interest expense for our Convertible Senior Notes, excluding amortization of debt issue costs, was less than $1 million, $84 million and $162 million, respectively. At December 31, 2012, the aggregate carrying amount of the 1.50% Series C Convertible Senior Notes included a liability component and an equity component of $62 million and $10 million, respectively. In February 2013, we redeemed the remaining $62 million aggregate principal amount of the Series C Convertible Senior Notes for an aggregate cash payment of $62 million.

Note 13—Derivatives and Hedging

Derivatives designated as hedging instruments—We had interest rate swaps, which were designated and qualified as fair value hedges, to reduce our exposure to changes in the fair values of the 5% Notes due February 2013, the 5.25% Senior Notes due March 2013 and the 4.95% Senior Notes due November 2015. In February and March 2013, the interest rate swaps designated as hedges of the 5% Notes and the 5.25% Senior Notes, respectively, expired. In June 2012, we terminated the interest rate swaps designated as hedges of the 4.95% Senior Notes due November 2015 and, in the year ended December 31, 2012, we received an aggregate net cash payment of $23 million.

We also had interest rate swaps, which were designated and qualified as a cash flow hedge, to reduce the variability of cash interest payments associated with the variable-rate borrowings under the TPDI Credit Facilities. In June 2013, we repaid the borrowings under the TPDI Credit Facilities, and we terminated these interest rate swaps. In connection with the termination, we made a net cash payment of $22 million, and we reclassified $9 million from accumulated other comprehensive loss to other expense, net.

Additionally, we had cross-currency interest rate swaps, which were designated and qualified as a cash flow hedge, to reduce the variability of cash interest payments and the final cash principal payment associated with the 11% Callable Bonds resulting from the changes in the U.S. dollar to Norwegian krone exchange rate. In March 2013, in connection with our redemption of the 11% Callable Bonds, we terminated these cross-currency interest rate swaps and the related security agreement with respect to the Harsh Environment Ultra-Deepwater Floaters Transocean Spitsbergen and Transocean Barents. As a result of the termination, we made a cash payment of $128 million and received a cash payment of NOK 705 million, which we applied to the redemption of the 11% Callable Bonds, and we reclassified $5 million from accumulated other comprehensive loss to other expense, net.

The effect on our consolidated statements of operations resulting from changes in the fair values of derivatives designated as cash flow hedges was as follows (in millions):

	Statement of operations classification	Years ended December 31, 2013	2012	2011
Loss associated with effective portion	Interest expense, net of amounts capitalized	$ (4)	$ (5)	$ (11)
Gain associated with effective portion	Other, net	—	6	—
Loss associated with terminations	Other, net	(14)	—	—

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The balance sheet classification and aggregate carrying amount of our derivatives designated as hedging instruments, measured at fair value, were as follows (in millions):

	Balance sheet classification	December 31, 2013	2012
Interest rate swaps, fair value hedges	Other current assets	$ —	$ 6
Interest rate swaps, cash flow hedges	Other long-term liabilities	—	13
Cross-currency swaps, cash flow hedges	Other current assets	—	1
Cross-currency swaps, cash flow hedges	Other assets	—	1

Derivatives not designated as hedging instruments—In connection with our acquisition of Aker Drilling, we assumed certain derivatives not designated as hedging instruments. In the years ended December 31, 2012 and 2011, we terminated these interest rate swaps not designated as hedging instruments and made aggregate cash payments of $14 million and $15 million, respectively.

Additionally, in August 2011, in connection with our acquisition of Aker Drilling, we entered into a forward exchange contract, which was not designated and did not qualify as a hedging instrument for accounting purposes, in order to offset the variability in the cash flows resulting from fluctuations in the U.S. dollar to Norwegian krone exchange rate. The forward exchange contract had aggregate notional amounts requiring us to pay $1.1 billion in exchange for receiving NOK 6.1 billion, representing an exchange rate of $1.00 to NOK 5.40. On September 28, 2011, we settled the full amount of the forward exchange contract and made a net cash payment of $78 million.

In connection with our sale transactions with Shelf Drilling, we received non-cash proceeds in the form of preference shares with a stated value of $195 million. The preference shares contain two embedded derivatives, which were not designated and did not qualify as hedging instruments for accounting purposes. At December 31, 2012, the embedded derivatives not designated as hedging instruments had an aggregate carrying amount of $2 million, recorded in other long-term liabilities. In June 2013, we completed the sale of the preference shares with the embedded derivatives. See Note 7—Discontinued Operations.

The effect on our consolidated statements of operations resulting from changes in the fair values of derivatives not designated as hedging instruments was as follows (in millions):

	Statement of operations classification	Years ended December 31, 2013	2012	2011
Loss associated with undesignated interest rate swaps	Interest expense, net of amounts capitalized	$ —	$ (1)	$ —
	Other, net	—	—	(78)

Loss associated with
undesignated forward
exchange contract

Note 14—Postemployment Benefit Plans

Defined benefit pension plans and other postretirement employee benefit plans

Overview—We maintain a single 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 seven funded defined benefit plans, primarily group pension schemes with life insurance companies, three of which we assumed in connection with our acquisition of Aker Drilling, 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.

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

	December 31, 2013			December 31, 2012		
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans
Discount rate	5.01%	4.92%	4.54%	4.19%	5.37%	3.63%
Compensation trend rate	4.24%	4.57%	n/a	4.21%	4.38%	n/a

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

	Year ended December 31, 2013			Year ended December 31, 2012			Year ended December 31, 2011		
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans
Discount rate	4.19%	5.13%	3.39%	4.67%	5.43%	4.27%	5.49%	5.73%	4.94%
Expected rate of return	7.48%	5.79%	n/a	7.47%	6.07%	n/a	8.49%	6.42%	n/a
Compensation trend rate	4.22%	4.21%	n/a	4.22%	4.61%	n/a	4.24%	4.62%	n/a
Health care cost trend rate									
-initial	n/a	n/a	8.07%	n/a	n/a	8.08%	n/a	n/a	8.08%
-ultimate	n/a	n/a	5.00%	n/a	n/a	5.00%	n/a	n/a	5.00%
-ultimate year	n/a	n/a	2020	n/a	n/a	2019	n/a	n/a	2018

“n/a” means not applicable.

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

	Year ended December 31, 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
Change in projected benefit obligation								
Projected benefit obligation, beginning of period	$ 1,452	$ 499	$ 58	$ 2,009	$ 1,260	$ 447	$ 53	$ 1,760
Actuarial (gains) losses, net	(147)	55	(7)	(99)	128	(15)	4	117
Service cost	55	27	1	83	49	31	1	81
Interest cost	63	25	2	90	59	24	2	85

Currency exchange rate changes	—	(11)	—	(11)	—	19	—	19
Benefits paid	(45)	(28)	(3)	(76)	(45)	(23)	(3)	(71)
Participant contributions	—	2	2	4	—	2	1	3
Special termination benefits	1	—	—	1	1	—	—	1
Settlements and curtailments	1	4	—	5	—	14	—	14
Projected benefit obligation, end of period	1,380	573	53	2,006	1,452	499	58	2,009
Change in plan assets								
Fair value of plan assets, beginning of period	948	422	—	1,370	769	351	—	1,120
Actual return on plan assets	149	45	—	194	116	28	—	144
Currency exchange rate changes	—	(10)	—	(10)	—	15	—	15
Employer contributions	64	50	1	115	108	49	2	159
Participant contributions	—	2	2	4	—	2	1	3
Benefits paid	(45)	(28)	(3)	(76)	(45)	(23)	(3)	(71)
Fair value of plan assets, end of period	1,116	481	—	1,597	948	422	—	1,370
Funded status, end of period	$ (264)	$ (92)	$ (53)	$ (409)	$ (504)	$ (77)	$ (58)	$ (639)
Balance sheet classification, end of period:								
Pension asset, non-current	$ —	$ 8	$ —	$ 8	$ —	$ 3	$ —	$ 3
Accrued pension liability, current	(2)	(23)	(4)	(29)	(3)	(24)	(3)	(30)
Accrued pension liability, non-current	(262)	(77)	(49)	(388)	(501)	(56)	(55)	(612)
Accumulated other comprehensive	(198)	(114)	1	(311)	(469)	(80)	(6)	(555)

income (loss) (a)

(a) Amounts are before income tax effect.

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

	December 31, 2013				December 31, 2012			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Projected benefit obligation	$ 1,380	$ 573	$ 53	$ 2,006	$ 1,452	$ 482	$ 58	$ 1,992
Fair value of plan assets	1,116	481	—	1,597	948	404	—	1,352

The accumulated benefit obligation for all defined benefit pension plans was $1.7 billion at December 31, 2013 and 2012. The aggregate accumulated benefit obligation and fair value of plan assets for plans with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	December 31, 2013				December 31, 2012			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Accumulated benefit obligation	$ 1,210	$ 374	$ 53	$ 1,637	$ 1,255	$ 335	$ 58	$ 1,648
Fair value of plan assets	1,116	351	—	1,467	948	298	—	1,246

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

As of December 31, 2013 and 2012, the weighted-average target and actual allocations of the investments for our funded Transocean Plans were as follows:

	December 31, 2013				December 31, 2012			
	Target allocation		Actual allocation		Target allocation		Actual allocation	
	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans
Equity securities	63%	51%	68%	53%	65%	49%	64%	49%

Fixed income securities	37%	15%	32%	17%	35%	14%	36%	17%
Other investments	—	34%	—	30%	—	37%	—	34%
Total	100%	100%	100%	100%	100%	100%	100%	100%

As of December 31, 2013, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2013								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Mutual funds									
U.S. equity funds	$ 610	$ —	$ 610	$ —	$ 43	$ 43	$ 610	$ 43	$ 653
Non-U.S. equity funds	141	—	141	3	209	212	144	209	353
Bond funds	357	—	357	—	83	83	357	83	440
Total mutual funds	1,108	—	1,108	3	335	338	1,111	335	1,446
Other investments									
Cash and money market funds	5	1	6	—	—	—	5	1	6
Property collective trusts	—	—	—	—	15	15	—	15	15
Investment contracts	—	—	—	—	130	130	—	130	130
Total other investments	5	1	6	—	145	145	5	146	151
Total investments	$ 1,113	$ 1	$ 1,114	$ 3	$ 480	$ 483	$ 1,116	$ 481	$ 1,597

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – continued

As of December 31, 2012, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2012								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Mutual funds									
U.S. equity funds	$ 525	$ —	$ 525	$ —	$ 32	$ 32	$ 525	$ 32	$ 557
Non-U.S. equity funds	120	—	120	3	176	179	123	176	299
Bond funds	296	—	296	—	73	73	296	73	369
Total mutual funds	941	—	941	3	281	284	944	281	1,225
Other investments									
Cash and money market funds	4	2	6	—	6	6	4	8	12
Property collective trusts	—	—	—	—	8	8	—	8	8
Investment contracts	—	—	—	—	125	125	—	125	125
Total other investments	4	2	6	—	139	139	4	141	145
Total investments	$ 945	$ 2	$ 947	$ 3	$ 420	$ 423	$ 948	$ 422	$ 1,370

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

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

Year ended December 31, 2013			Year ended December 31, 2012			Year ended December 31, 2011		
U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans

Service cost	$ 55	$ 27	$ 82	$ 49	$ 31	$ 80	$ 43	$ 21	$ 64
Interest cost	63	25	88	59	24	83	58	22	80
Expected return on plan assets	(70)	(25)	(95)	(62)	(22)	(84)	(63)	(23)	(86)
Settlements and curtailments	2	3	5	3	19	22	2	1	3
Special termination benefits	1	—	1	1	—	1	—	—	—
Actuarial losses, net	45	3	48	41	4	45	23	4	27
Prior service cost, net	(1)	1	—	(2)	1	(1)	(1)	—	(1)
Net periodic benefit costs	$ 95	$ 34	$ 129	$ 89	$ 57	$ 146	$ 62	$ 25	$ 87

For the OPEB Plans, the combined components of net periodic benefit costs, including service cost, interest cost, recognized net actuarial losses, prior service cost amortization and special termination benefits were $3 million, $3 million and $1 million in the years ended December 31, 2013, 2012 and 2011, respectively.

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

	December 31, 2013				December 31, 2012			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ 205	$ 116	$ 1	$ 322	$ 477	$ 80	$ 8	$ 565
Prior service cost, net	(7)	—	(2)	(9)	(8)	—	(2)	(10)
Transition obligation, net	—	(2)	—	(2)	—	—	—	—
Total	$ 198	$ 114	$ (1)	$ 311	$ 469	$ 80	$ 6	$ 555

The following table presents the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit costs during the year ending December 31, 2014 (in millions):

	Year ending December 31, 2014			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ 20	$ 5	$ —	$ 25
Prior service cost, net	(1)	—	(1)	(2)
Transition obligation, net	—	—	—	—
Total amount expected to be recognized	$ 19	$ 5	$ (1)	$ 23

Funding contributions—In the years ended December 31, 2013, 2012 and 2011, we contributed $115 million, $159 million and $103 million, respectively, to the Transocean Plans and the OPEB Plans using our cash flows from operations. For the year ending December 31, 2014, we expect to contribute $69 million to the Transocean Plans, and we expect to fund benefit payments of approximately $3 million for the OPEB Plans as costs are incurred.

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

	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Years ending December 31,				
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

Defined contribution plans

We sponsor two defined contribution plans, including (1) one qualified defined contribution savings plan covering certain employees working in the U.S. (the “U.S. Savings Plan”) and (2) one defined contribution savings plan covering certain employees working outside the U.S. (the “Non-U.S. Savings Plan”).

For the U.S. Savings Plan, we make a matching contribution of up to 6.0 percent of each participant’s base salary based on the participant’s contribution to the plan. For the Non-U.S. Savings Plan, in addition to a matching contribution of up to 6.0 percent of each participant’s base salary based on the participant’s contribution to the plans, we contribute between 4.5 percent and 6.5 percent of each participant’s base salary, based on the participant’s years of eligible service. In the years ended December 31, 2013, 2012 and 2011, we recognized expense of $88 million, $85 million and $82 million, respectively, related to our defined contribution plans.

One-time termination benefit plans

During the year ended December 31, 2013, we committed to a plan to improve the organizational efficiency of our shore-based support activities worldwide. In connection with this initiative, we established certain one-time termination benefit plans for shore-based employees in the U.S. and the U.K. and for expatriate resident employees worldwide that were or are expected to be involuntarily terminated during the period from May 2013 through December 2014. The plans generally offer affected individuals a lump sum benefit payment equivalent to between four weeks and 52 weeks of the employee's weekly base salary, calculated based on the employee's annual base salary and years of service with additional amounts paid to those employees that would otherwise have been eligible for a bonus payment under our annual incentive program, and allowed for early retirement and immediate vesting for qualifying individuals under our defined benefit plans and other postretirement employee benefit plans.

In the year ended December 31, 2013, we recognized expense of $32 million, associated with severance-related costs under these one-time termination benefit plans. In the year ended December 31, 2013, we made payments of $21 million for involuntary terminations under these plans.

Note 15—Commitments and Contingencies

Lease obligations

We have operating lease obligations expiring at various dates, principally for real estate, office space and office equipment. In the years ended December 31, 2013, 2012 and 2011, our rental expense for all operating leases, including operating leases with terms of less than one year, was approximately $128 million, $97 million and $169 million, respectively.

We also have a capital lease obligation, which is due to expire in August 2029. In each of the years ended December 31, 2013, 2012 and 2011, depreciation expense associated with Petrobras 10000, the asset held under capital lease, was $20 million. At December 31, 2013 and 2012, the aggregate carrying amount of this asset held under capital lease was as follows (in millions):

	December 31, 2013	December 31, 2012
Property and equipment, cost	$ 752	$ 745
Accumulated depreciation	(84)	(64)
Property and equipment, net	$ 668	$ 681

As of December 31, 2013, the aggregate future minimum rental payments related to our non-cancellable operating leases and the capital lease were as follows (in millions):

	Capital lease	Operating leases
Years ending December 31,		
2014	$ 66	$ 25
2015	71	25
2016	72	20
2017	72	11
2018	72	10
Thereafter	765	87
Total future minimum rental payment	1,118	$ 178
Less amount representing imputed interest	(481)	
Present value of future minimum rental payments under capital leases	637	
Less current portion included in debt due within one year	(20)	
Long-term capital lease obligation	$ 617	

Purchase obligations

At December 31, 2013, the aggregate future payments required under our purchase obligations, primarily related to our newbuilds, were as follows (in millions):

	Purchase obligations
Years ending December 31,	
2014	$ 1,691
2015	861
2016	1,649
2017	353
Total	$ 4,554

Macondo well incident settlement obligations

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").

On January 3, 2013, we reached an agreement with the U.S. Department of Justice ("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.

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 initial payment to the National Fish and Wildlife Foundation and $2 million for the initial payment to the National Academy of Sciences. In the year ended December 31, 2013, we paid $404 million, including interest at a rate of 2.15 percent, in satisfaction of amounts due under the Consent Decree. At December 31, 2013, the aggregate future payments required under our outstanding settlement obligations under the Plea Agreement and the Consent Decree, excluding interest, were as follows (in millions):

	Plea Agreement	Consent Decree	Settlement obligations
Years ending December 31,			
2014	$ 60	$ 400	$ 460
2015	60	200	260
2016	60	—	60
2017	60	—	60
Total settlement obligations	$ 240	$ 600	$ 840

The resolution with the DOJ of such civil and potential criminal claims did not include potential claims arising from the False Claims Act investigation. As part of the settlement discussions, however, we inquired whether the U.S. intends to pursue any actions under the False Claims Act as discussed below. In response, the DOJ sent us a letter stating that the Civil Division of the DOJ, based on facts then known, was no longer pursuing any investigation or claims, and did not have any present intention to pursue any investigation or claims, under the False Claims Act against the various Transocean entities for their involvement in the Macondo well incident.

We also agreed that payments made pursuant to the Plea Agreement or the Consent Decree are not deductible for tax purposes and that payments made pursuant to the Consent Decree are not to be used as a basis for indemnity or reimbursement from BP or other non-insurer defendants named in the complaint by the U.S.

Plea Agreement—Pursuant to the Plea Agreement, which was accepted by the court on February 14, 2013, one of our subsidiaries pled guilty to one misdemeanor count of negligently discharging oil into the U.S. Gulf of Mexico, in violation of the Clean Water Act ("CWA"). 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.

Our subsidiary also agreed to be subject to probation through February 2018. The DOJ agreed, subject to the provisions of the Plea Agreement, not to further prosecute us for certain conduct generally regarding matters under investigation by the DOJ's Deepwater Horizon Task Force. In addition, we agreed to continue to cooperate with the Deepwater Horizon Task Force in any ongoing investigation related to or arising from the accident.

Consent Decree—Pursuant to the Consent Decree, which was approved by the court on February 19, 2013, we agreed to take specified actions relating to operations in U.S. waters, including, among other things, the design and implementation of, and compliance with, additional systems and procedures; blowout preventer certification and reports; measures to strengthen well control competencies, drilling monitoring, recordkeeping, incident reporting, risk management and oil spill training, exercises and response planning; communication with operators; alarm systems; transparency and responsibility for matters relating to the Consent Decree; and technology innovation, with a first emphasis on more efficient, reliable blowout preventers. We agreed to submit a performance plan (the "Performance Plan") for approval by the DOJ within 120 days after the date of entry of the Consent Decree. On June 14, 2013, we submitted our proposed 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.

The Consent Decree also provides for the appointment of (i) an independent auditor to review, audit and report on our compliance with the injunctive provisions of the Consent Decree and (ii) an independent process safety consultant to review, report on and assist with respect to the process safety aspects of the Consent Decree, including operational risk identification and risk management. The Consent Decree requires certain plans, reports and submissions be made and be acceptable to the U.S. and also requires certain publicly available filings.

Under the terms of the Consent Decree, the U.S. agreed not to sue Transocean Ltd. and certain of our subsidiaries and certain related individuals for civil or administrative penalties for the Macondo well incident under specified provisions of the CWA, the Outer Continental Shelf Lands Act ("OSCLA"), the Endangered Species Act, the Marine Mammal Protection Act, the National Marine Sanctuaries Act, the federal Oil and Gas Royalty Management Act, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Emergency Planning and Community Right to Know Act and the Clean Air Act. In addition, the Consent Decree resolved our appeal of the incidents of noncompliance under the OSCLA issued by the Bureau of Safety and Environmental Enforcement ("BSEE") on October 12, 2011 without any admission of liability by us, and we subsequently dismissed our appeal.

The Consent Decree did not resolve the rights of the U.S. with respect to all other matters, including certain liabilities under the Oil Pollution Act of 1990 (the "OPA") for removal costs or resulting from a natural resources damages assessment ("NRDA"). However, the district court previously held that we are not liable under the OPA for damages caused by subsurface discharge from the Macondo well. If this ruling is upheld on appeal, our NRDA liability would be limited to any such damages arising from the above-surface discharge. The court has not yet ruled whether we could be liable for removal costs to the U.S. or any state or local government as an operator of the Macondo well.

We may request termination of the Consent Decree after we have: (i) completed timely the civil penalty payment requirements of the Consent Decree; (ii) operated under a fully approved Performance Plan required under the Consent Decree through a five-year performance period ending February 2017; (iii) complied with the terms of the Performance Plan and certain provisions of the Consent Decree, generally relating to a framework and outline of measures to improve performance, for at least 12 consecutive months prior to seeking termination; and (iv) complied with the other requirements of the Consent Decree, including payment of any stipulated penalties and compliant reporting.

EPA Agreement—On February 25, 2013, we and the U.S. Environmental Protection Agency ("EPA") entered into an administrative agreement (the "EPA Agreement"), which has a five-year term. The EPA Agreement resolved all matters relating to suspension, debarment and statutory disqualification arising from the matters contemplated by the Plea Agreement. Subject to our compliance with the terms of the EPA Agreement, the EPA agreed that it will not suspend, debar or statutorily disqualify us and will lift any existing suspension, debarment or statutory disqualification.

In the EPA Agreement, we agreed to, among other things, (1) comply with our obligations under the Plea Agreement and the Consent Decree; (2) continue the implementation of certain programs and systems, including the scheduled revision of our environmental management system and maintenance of certain compliance and ethics programs; (3) comply with certain employment and contracting procedures; (4) engage independent compliance auditors and a process safety consultant to, among other things, assess and report to the EPA on our compliance with the terms of the Plea Agreement, the Consent Decree and the EPA Agreement; and (5) give reports and notices with respect to various matters, including those relating to compliance, misconduct, legal proceedings, audit reports, the EPA Agreement, the Consent Decree and the Plea Agreement. 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.

Macondo well incident contingencies

Overview—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 (see "—Insurance coverage"). 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.

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"). The BP/PSC Settlement agreement provides that (a) to the extent permitted by law, BP will assign to the settlement class certain of BP's claims, rights and recoveries against us for damages with protections such that the settlement class is barred from collecting any amounts from us unless it is finally determined that we cannot recover such amounts from BP, and (b) the settlement class releases all claims for compensatory damages against us but purports to retain claims for punitive damages against us.

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 have 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 had been interpreted with respect to BEL Claims. On December 2, 2013, the panel ordered a temporary halt to certain of the BEL Claims pending further proceedings in the MDL Court.

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 ruled on these motions.

In May 2013, we filed a motion seeking partial summary judgment on claims asserted by BP against us seeking damages from loss of the well and for source-control and cleanup costs (the "Direct Damages" claims). The Direct Damages claims are included in the claims BP assigned to the economic and property damages settlement class. The motion argues that BP released the Direct Damages claims in its contract with us and that the release is enforceable even if we are found grossly negligent. Some courts have held that such agreements will not be enforced if the defendant is found grossly negligent. The MDL Court has not ruled on this motion.

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 MDL Court has not yet ruled on the issues tried in the first phase of the trial.

If the MDL Court finds in this phase of the trial that we were grossly negligent, we will be exposed to at least three litigation risks: (1) the MDL Court could award punitive damages under general maritime law to plaintiffs who own property damaged by oil and to plaintiffs who are commercial fishermen; (2) the MDL Court could find that our gross negligence voids the release BP gave us in the drilling contract for direct claims by BP, which BP has assigned to the plaintiffs in the BP/PSC settlement; and (3) we could be liable for all other oil pollution damages claims, including claims resulting from NRDA, if the court of appeals were to reverse a prior ruling that BP owes us indemnity for these claims even in the event of gross negligence. This potential liability for all other oil pollution damage claims could also arise regardless of a finding as to our gross negligence, for which we believe we are owed indemnity, if the MDL Court were in any event to find a core breach of the drilling contract, thereby nullifying our indemnity. Our four pending motions for partial judgment on the pleadings or partial summary judgment, if successful, could reduce or eliminate our exposure to these claims. A finding of gross negligence against us or against BP or a finding that either we or BP violated certain safety regulations would also result in the removal of the statutory liability caps under OPA. Under the MDL Court's present ruling, however, our liability for damages under OPA is limited to damages caused by discharge on or above the surface of the water.

The second phase of the trial began on September 30, 2013 and concluded on October 17, 2013. This phase addressed BP's conduct related to stopping the release of hydrocarbons after April 22, 2010 and quantification of the amount of oil discharged. In light of BP's criminal plea agreement with the DOJ acknowledging that it provided the government with false or misleading information throughout the spill response, we argued at trial that BP's fraud delayed the final capping of the well and that we should not be liable for damages resulting from this delay. The parties filed post-trial briefs and proposed findings of fact and conclusions of law on December 20, 2013. The MDL Court has not yet ruled on the issues tried in the second phase of the trial.

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

Litigation—As of December 31, 2013, approximately 1,400 actions or claims were pending against us, along with other unaffiliated defendants, in state and federal courts. Additionally, government agencies have initiated investigations into the Macondo well incident. We have categorized below the nature of the legal actions or claims. We are evaluating all claims and intend to vigorously defend any claims and pursue any and all defenses available. In addition, we believe we are entitled to contractual defense and indemnity for all wrongful death and personal injury claims made by non-employees and third-party subcontractors' employees as well as all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See "—Contractual indemnity."

Wrongful death and personal injury—As of December 31, 2013, we have been named, along with other unaffiliated defendants, in nine complaints that were pending in state and federal courts in Louisiana and Texas involving multiple plaintiffs that allege wrongful death and other personal injuries arising out of the Macondo well incident. Nine complaints involve fatalities and 63 complaints seek recovery for bodily injuries. A number of these lawsuits have been settled. Per the order of the Multidistrict Litigation Panel ("MDL"), all claims but one have been centralized for discovery purposes in the MDL Court. The complaints generally allege negligence and seek awards of unspecified economic damages and punitive damages. BP, MI-SWACO, Weatherford International Ltd. and Cameron International Corporation ("Cameron") and certain of their affiliates, have, based on contractual arrangements, also made indemnity demands upon us with respect to personal injury and wrongful death claims asserted by our employees or representatives of our employees against these entities. See "—Contractual indemnity."

Economic loss—As of December 31, 2013, we and certain of our subsidiaries were named, along with other unaffiliated defendants, in 949 pending individual complaints as well as 199 putative class-action complaints that were pending in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Florida and possibly other courts. The complaints generally allege, among other things, potential economic losses as a result of environmental pollution arising out of the Macondo well incident and are based primarily on the OPA and state OPA analogues. The plaintiffs are generally seeking awards of unspecified economic, compensatory and punitive damages, as well as injunctive relief. No classes have been certified at this time. Most of these actions have either been transferred to or are the subject of motions to transfer to the MDL. See "—Contractual indemnity."

Cross-claims, counter-claims, and third party claims—In April 2011, several defendants in the MDL litigation filed cross-claims or third-party claims against us and certain of our subsidiaries, and other defendants. BP filed a claim seeking contribution under the OPA and maritime law, subrogation and claimed breach of contract, unseaworthiness, negligence and gross negligence. Through these claims, BP sought to recover from us damages it has paid or may pay arising from the Macondo well incident. BP also sought a declaration that it is not liable in contribution, indemnification, or otherwise to us. Anadarko Petroleum Corporation ("Anadarko"), which owned a 25 percent non-operating interest in the Macondo well, asserted claims of negligence, gross negligence, and willful misconduct and is seeking indemnity under state and maritime law and contribution under maritime and state law as well as OPA. MOEX Offshore 2007 LLC ("MOEX"), which owns a 10 percent non-operating interest in the Macondo well, filed claims of negligence under state and maritime law, gross negligence under state law, gross negligence and willful misconduct under maritime law and is seeking indemnity under state and maritime law and contribution under maritime law and OPA. Cameron, the manufacturer and designer of the blowout preventer, asserted multiple claims for contractual indemnity and declarations regarding contractual obligations under various contracts and quotes and is also seeking non-contractual indemnity and contribution under maritime law and OPA. As part of the BP/PSC Settlement, one or more of these claims against us and certain of our subsidiaries have been assigned to the PSC settlement class. Halliburton Company ("Halliburton"), which provided cementing and mud-logging services to the operator, filed a claim against us seeking contribution and indemnity under maritime law, contractual indemnity and alleging negligence and gross negligence. Additionally, certain other third parties filed claims against us for indemnity and contribution.

In April 2011, we filed cross-claims and counter-claims against BP, Halliburton, Anadarko, MOEX, certain of these parties' affiliates, the U.S. and certain other third parties. We seek indemnity, contribution, including contribution under OPA, and subrogation under OPA, and we have asserted claims for breach of warranty of workmanlike performance, strict liability for manufacturing and design defect, breach of express contract, and damages for the difference between the fair market value of Deepwater Horizon and the amount received from insurance proceeds. The Consent Decree limits our ability to seek indemnification or reimbursement with respect to certain of these matters against the owners of the Macondo well and dismissed our claims against the U.S. We are not pursuing arbitration on the key contractual issues with BP; instead, we are relying on the court to resolve the disputes.

Federal securities claims—A federal securities proposed class action is currently pending in the U.S. District Court, Southern District of New York, naming us and former chief executive officers of Transocean Ltd. and one of our acquired companies as defendants. In the action, a former shareholder of the acquired company alleges that the joint proxy statement related to our shareholder meeting in connection with our merger with the acquired company violated Section 14(a) of the Securities Exchange Act of 1934 (the "Exchange Act"), Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The plaintiff claims that the acquired company's shareholders received inadequate consideration for their shares as a result of the alleged violations and seeks compensatory and rescissory damages and attorneys' fees on behalf of itself and the proposed class members. In addition, we are obligated to pay the defense fees and costs for the individual defendants, which may be covered by our directors' and officers' liability insurance, subject to a deductible. On October 4, 2012, the court denied our motion to dismiss the action. On June 27, 2013, the Second Circuit Court of Appeals ruled in the unrelated action on an issue that could be relevant to the disposition of this case in a manner that we believe supports our position that the plaintiff's existing claims alleged in the action are time-barred. On August 30, 2013, we filed a motion to dismiss on the ground that the claims are time-barred, citing the Second Circuit Court of Appeals' ruling. Plaintiffs filed an opposition to our motion to dismiss on September 20, 2013, and we filed a reply to that opposition on September 24, 2013. Oral argument has not been scheduled, and the motion remains under submission.

Other federal statutes—Several of the claimants have made assertions under the statutes, including the CWA, the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Air Act, the CERCLA and the Emergency Planning and Community Right-to-Know Act.

Shareholder derivative claims—In June 2010, two shareholder derivative suits were filed in the state district court in Texas by our shareholders 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. Any recovery of the damages or disgorgement by the plaintiffs in these actions would be paid to us. If the plaintiffs prevail, we could be required to pay plaintiffs' attorneys' fees. In addition, we are obligated to pay the defense fees and costs for the individual defendants, which may be covered by our directors' and officers' liability insurance, subject to a deductible. The two actions have been consolidated before a single judge. In August 2012, the defendants filed a motion to dismiss the complaint on the grounds that the actions must be maintained in the courts of Switzerland and that the plaintiffs lack standing to assert the claims alleged. In December 2012, in response to defendants' motion to dismiss for lack of standing, the plaintiffs dismissed their action without prejudice. In January 2013, one of the plaintiffs re-filed a previously dismissed complaint seeking to recover damages to Transocean Ltd. and disgorgement of all profits, benefits, and other compensation from the individual defendants. Certain defendants filed a motion to dismiss the re-filed complaint in March 2013 on the ground that the action must be maintained in the courts of Switzerland. On July 30, 2013, the court granted the motion to dismiss. 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.

U.S. Department of Justice claims—On December 15, 2010, the DOJ filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleged violations under OPA and the CWA, including claims for per barrel civil penalties of up to $1,100 per barrel or up to $4,300 per barrel if gross negligence or willful misconduct is established, and the DOJ reserved its rights to amend the complaint to add new claims and defendants. The U.S. government has estimated that up to 4.1 million barrels of oil were discharged and subject to penalties. The complaint asserted that all defendants named are jointly and severally liable for all removal costs and damages resulting from the Macondo well incident. In response to the U.S. complaint, BP and Anadarko filed claims seeking contribution from us for any damages for which they may be found liable, including OPA damages. 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 of the discharges from the Macondo well on the theory that discharges not only came from the well but also from the blowout preventer and riser, appurtenances of Deepwater Horizon.

On January 9, 2012, we filed our opposition to the motion and filed a cross-motion for partial summary judgment seeking a ruling that we are not liable for the subsurface discharge of hydrocarbons. On February 22, 2012, the MDL Court 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 MDL Court did not rule on whether we could be liable for removal costs to the U.S. or any state or local government as an operator of 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. However, the MDL 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. We subsequently entered into an agreement with the DOJ regarding liability to the U.S. with respect to its CWA claim through the Consent Decree. The Consent Decree did not resolve the rights of the U.S. with respect to certain liabilities under OPA for removal costs or resulting from NRDA. In August and September 2012, Anadarko and BP filed appeals to the Fifth Circuit Court of Appeals, in which they argue that, under the CWA, the below-surface discharge was discharged from the vessel, not from the well facility. Briefing was completed in August 2013, and the Court of Appeals heard oral argument on December 4, 2013. As a result of our Consent Decree agreement, the outcome of this appeal would not affect our CWA civil penalty liability for the Macondo well incident, but it could establish a legal precedent as to whether the owner and operator of a drilling vessel are liable for CWA civil penalties for a subsurface discharge. See "—Macondo well incident settlement obligations."

In addition to the civil complaint, the DOJ served us with civil investigative demands on December 8, 2010. These demands were part of an investigation by the DOJ to determine if we made false claims, or false statements in support of claims, in violation of the False Claims Act, in connection with the operator's acquisition of the leasehold interest in the Mississippi Canyon Block 252, Gulf of Mexico and drilling operations on Deepwater Horizon. As part of the settlement discussions, we inquired whether the U.S. intends to pursue any actions under the False Claims Act. In response, the DOJ sent us a letter stating that the Civil Division of the DOJ, based on facts then known, is no longer pursuing any investigation or claims, and did not have any present intention to pursue any investigation or claims, under the False Claims Act against the various Transocean entities for their involvement in the Macondo well incident.

As noted above, the DOJ also conducted a criminal investigation into the Macondo well incident. On March 7, 2011, the DOJ announced the formation of the Deepwater Horizon Task Force to lead the criminal investigation. The task force investigated 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. As discussed above, on January 3, 2013, we entered into the Plea Agreement with the DOJ resolving these claims. See "—Macondo well incident settlement obligations."

State and other government claims—In June 2010, the Louisiana Department of Environmental Quality (the "LDEQ") issued a consolidated compliance order and notice of potential penalty to us and certain of our subsidiaries asking us to eliminate and remediate discharges of oil and other pollutants into waters and property located in the State of Louisiana, and to submit a plan and report in response to the order. In October 2010, the LDEQ rescinded its enforcement actions against us and our subsidiaries but reserved its rights to seek civil penalties for future violations of the Louisiana Environmental Quality Act. In September 2010, the State of Louisiana filed an action for declaratory judgment seeking to designate us as a responsible party under OPA and the Louisiana Oil Spill Prevention and Response Act for the discharges emanating from the Macondo well.

Prior to the possible expiration of the statute of limitations in April 2013, suits were filed by over 200 state, local and foreign governments, including the U.S. States of Alabama, Florida, Louisiana, Mississippi and Texas; the Mexican States of Veracruz, Quintana Roo and Tamaulipas ("Mexican States"); the Federal Government of Mexico and by other local governments by and on behalf of multiple towns and parishes. These governments generally assert claims under OPA, other statutory environmental state claims and various common law claims. A local government master complaint also was filed in which cities, municipalities, and other local government entities can, and have, joined. Most of these new government cases, including the suits filed by the attorneys general of Alabama, Florida, Louisiana, Mississippi and Texas, have been transferred to the MDL.

The Mexican States' OPA claims were subsequently dismissed for failure to demonstrate that recovery under OPA was authorized by treaty or executive agreement. However, the Court preserved some of the Mexican States' negligence and gross negligence claims, but only to the extent there has been a physical injury to a proprietary interest. On September 6, 2013, the MDL Court ruled that the Federal Government of Mexico rather than the Mexican States had the proprietary interest in the property and natural resources allegedly injured by the spill and, on that basis, dismissed the remaining claims of the Mexican States. The Mexican States have filed a notice of appeal. The claims of the Federal Government of Mexico remain pending. On September 18, 2013, the Mexican State of Yucatan filed a suit similar to those filed by the other Mexican States.

By letter dated May 5, 2010, the Attorneys General of the five Gulf Coast states of Alabama, Florida, Louisiana, Mississippi and Texas informed us that they intend to seek recovery of pollution cleanup costs and related damages arising from the Macondo well incident. In addition, by letter dated June 21, 2010, the Attorneys General of the 11 Atlantic Coast states of Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Rhode Island and South Carolina informed us that their states have not sustained any damage from the Macondo well incident but they would like assurances that we will be responsible financially if damages are sustained. We responded to each letter from the Attorneys General and indicated that we intend to fulfill our obligations as a responsible party for any discharge of oil from Deepwater Horizon on or above the surface of the water, and we assume that the operator will similarly fulfill its obligations under OPA for discharges from the undersea well.

On August 26, 2011, the MDL Court ruled on the motion to dismiss certain economic loss claims. The court ruled that state law, both statutory and common law, is inapplicable to the Macondo well incident. Accordingly, all claims brought under state law were dismissed. Secondly, general maritime law claims that do not allege physical damage to a proprietary interest were dismissed, unless the claim falls into the commercial fisherman exception. The court ruled that OPA claims for economic loss do not require physical damage to a proprietary interest. Third, the MDL Court ruled that presentment under OPA is a mandatory condition precedent to filing suit against a responsible party. Finally, the MDL Court ruled that claims for punitive damages may be available under general maritime law in claims against responsible parties and non-responsible parties. Certain Louisiana parishes have appealed portions of this ruling.

The state, local and foreign government claims include claims under OPA. On February 22, 2012, the MDL Court ruled that we are not a responsible party under OPA for damages with respect to subsurface discharge from the Macondo well.

Prior to the possible expiration of the three-year statute of limitations on April 20, 2013, additional private plaintiffs filed new lawsuits relating to the Macondo well incident. We are named as a defendant in many but not all of the new lawsuits. The lawsuits seek recoveries for economic loss and punitive damages and allege claims under OPA, maritime law and state law. Some of the new lawsuits were filed in the MDL Court, but many were filed in state and federal courts outside of the MDL Court. Most of these cases have been transferred to the MDL and, consistent with our prior experience, we expect the remaining cases to be transferred to the MDL Court.

Wreck removal—By letter dated December 6, 2010, the U.S. Coast Guard requested us to formulate and submit a comprehensive oil removal plan to remove any diesel fuel contained in the sponsons and fuel tanks that can be recovered from Deepwater Horizon. We have conducted a survey of the rig wreckage and have confirmed that no diesel fuel remains on the rig. The U.S. Coast Guard has not requested that we remove the rig wreckage from the sea floor. In October 2012, a new sheen was reported and preliminarily determined to have originated from the Macondo well. We understand that BP was notified of the sheen in early September 2012 and had commenced an investigation to determine the source, whether the oil and mud were from the sea floor, the rig or rig equipment, or other sources. In February 2013, the U.S. Coast Guard submitted a request seeking analysis and recommendations as to the potential life of the rig's riser and cofferdam resting on the seafloor and potential remediation or removal options. We have insurance coverage for wreck removal for up to 25 percent of Deepwater Horizon's insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our remaining excess liability limits.

Insurance coverage—At the time of the Macondo well incident, our excess liability insurance program offered aggregate insurance coverage of $950 million, excluding a $15 million deductible and a $50 million self-insured layer through our wholly owned captive insurance subsidiary. This excess liability insurance coverage consisted of a first and a second layer of $150 million each, a third and fourth layer of $200 million each and a fifth layer of $250 million. The first four excess layers have similar coverage and contractual terms, while the $250 million fifth layer is on a different policy form, which varies to some extent from the underlying coverage and contractual terms. Generally, we believe that the policy forms for all layers include coverage for personal injury and fatality claims of our crew and vendors, actual and compensatory damages, punitive damages and related legal defense costs and that the policy forms for the first four excess layers provide coverage for fines; however, we do not expect payments deemed to be criminal in nature to be covered by any of the layers.

In May 2010, we received notice from BP maintaining that it believes that it is entitled to additional insured status under our excess liability insurance program. Our insurers have also received notices from Anadarko and MOEX advising of their intent to preserve any rights they may have to our insurance policies as an additional insured under the drilling contract. In response, our wholly owned captive insurance subsidiary and our first four excess layer insurers filed declaratory judgment actions in the Houston Division of the U.S. District Court for the Southern District of Texas in May 2010 seeking a judgment declaring that they have limited additional insured obligations to BP, Anadarko and MOEX. We are parties to the declaratory judgment actions, which were transferred to the MDL Court for discovery and other purposes. On November 15, 2011, the MDL Court ruled that BP's coverage rights are limited to the scope of our indemnification of BP in the drilling contract. A final judgment was entered against BP, Anadarko and MOEX, and BP appealed. On March 1, 2013, the Fifth Circuit Court of Appeals issued an opinion reversing the decision of the MDL Court, and holding that BP is an unrestricted additional insured under the policies issued by our wholly owned captive insurance company and the first four excess layer insurers. We and the insurers filed petitions for rehearing with the Fifth Circuit Court of Appeals. On August 29, 2013, the Fifth Circuit Court of Appeals issued an opinion withdrawing the March 1, 2013 opinion and certifying certain insurance law questions to the Texas Supreme Court. On September 6, 2013, the Texas Supreme Court accepted certification of these questions. The parties' briefing to the Texas Supreme Court is scheduled to be completed by March 10, 2014.

We believe that additional insured coverage for BP, Anadarko or MOEX under the $250 million fifth layer of our insurance program is limited to the scope of our indemnification of BP under the drilling contract. While we cannot predict the outcome of the matter before the Texas Supreme Court or the outcome of any subsequent proceedings in the Fifth Circuit, we do not expect them to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

On June 17, 2011 and July 31, 2012, our first layer and second layer of excess insurers, respectively, each representing $150 million of insurance coverage, filed interpleader actions. On February 14, 2013, the third and fourth layers, each representing $200 million of insurance coverage, filed interpleader actions substantially similar to the prior filings. The insurers contend that they face multiple, and potentially competing, claims to the relevant insurance proceeds. In these actions, the insurers effectively ask the court to manage disbursement of the funds to the alleged claimants, as appropriate, and discharge the insurers of any additional liability. The parties to the first and second excess insurer interpleader actions have executed protocol agreements to facilitate the reimbursement and funding of settlements of personal injury and fatality claims of our crew and vendors (collectively, "crew claims") using insurance funds and claims were submitted to the court for review. Following the court's determination and approval of the amounts to be paid by the insurers with respect to the crew claims submitted by the parties to date, the first layer of excess insurers made reimbursement payments to the parties for crew claims during the year ended December 31, 2013. Parties to the third and fourth excess insurer interpleader actions have agreed to adjourn the deadline for responses to the pleadings to an unspecified date that will follow a decision in another action that pertains to our insurance.

Contractual indemnity—Under our drilling contract for Deepwater Horizon, the operator has agreed, among other things, to assume full responsibility for and defend, release and indemnify us from any loss, expense, claim, fine, penalty or liability for pollution or contamination, including control and removal thereof, arising out of or connected with operations under the contract other than for pollution or contamination originating on or above the surface of the water from hydrocarbons or other specified substances within the control and possession of the contractor, as to which we agreed to assume responsibility and protect, release and indemnify the operator. Although we do not believe it is applicable to the Macondo well incident, we also agreed to indemnify and defend the operator up to a limit of $15 million for claims for loss or damage to third parties arising from pollution caused by the rig while it is off the drilling location, while the rig is underway or during drive off or drift off of the rig from the drilling location. The operator has also agreed, among other things, (1) to defend, release and indemnify us against loss or damage to the reservoir, and loss of property rights to oil, gas and minerals below the surface of the earth and (2) to defend, release and indemnify us and bear the cost of bringing the well under control in the event of a blowout or other loss of control. We agreed to defend, release and indemnify the operator for personal injury and death of our employees, invitees and the employees of our subcontractors while the operator agreed to defend, release and indemnify us for personal injury and death of its employees, invitees and the employees of its other subcontractors, other than us. We have also agreed to defend, release and indemnify the operator for damages to the rig and equipment, including salvage or removal costs.

Although we believe we are entitled to contractual defense and indemnity, the operator has sought to avoid its indemnification obligations. In April 2011, the operator filed a claim seeking a declaration that it is not liable to us in contribution, indemnification, or otherwise. On November 1, 2011, we filed a motion for partial summary judgment, seeking enforcement of the indemnity obligations for pollution and civil fines and penalties contained in the drilling contract with the operator. On January 26, 2012, the court ruled that the drilling contract requires the operator 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 ruling is not currently subject to appeal, but may be appealed once a final judgment in the case is rendered. The court also held that the operator does not owe us indemnity to the extent that we are held liable for civil penalties under the CWA or for punitive damages, and we have since agreed with the DOJ that we will not seek indemnity or reimbursement of our Consent Decree payments from the operator or the other non-insurer defendants named in the complaint by the U.S. The court deferred ruling on the operator's argument that we committed a core breach of the drilling contract or otherwise materially increased the operator's risk or prejudiced its rights so as to vitiate the operator's indemnity obligations. Our motion for partial summary judgment and the court's ruling did not address the issue of contractual indemnity for criminal fines and penalties. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy. Our motion did not ask the court to rule on the validity of BP's agreement in the drilling contract to release us from any claims asserted by BP itself. Some courts have held that such agreements will not be enforced if the defendant is found to be grossly negligent. 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 MDL Court has not yet ruled on this motion.

Other legal proceedings

Asbestos litigation—In 2004, several of our subsidiaries were named, along with numerous other unaffiliated defendants, in 21 complaints filed on behalf of 769 plaintiffs in the Circuit Courts of the State of Mississippi and which claimed injuries arising out of exposure to asbestos allegedly contained in drilling mud during these plaintiffs' employment in drilling activities between 1965 and 1986. The Circuit Courts subsequently dismissed the original 21 multi-plaintiff complaints and required each plaintiff to file a separate lawsuit. After certain individual claims were dismissed, 593 separate lawsuits remained, each with a single plaintiff. We have or may have direct or indirect interest in a total of 20 cases in Mississippi. The complaints generally allege that the defendants used or manufactured asbestos-containing drilling mud additives for use in connection with drilling operations and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. The plaintiffs generally seek awards of unspecified compensatory and punitive damages. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling-related products that contained asbestos. With the exception of cases pending in Jones and Jefferson counties, these cases are being governed for discovery and trial setting by a single Case Management Order entered by a Special Master appointed by the court to preside over the cases. Of the 20 cases in which we have or may have an interest, two have been scheduled for trial. During the year ended December 31, 2013, one of these two cases was resolved through a negotiated settlement for a nominal sum. In the other case, we were not named as a direct defendant, but the Special Master granted a Motion for Summary Judgment based on the absence of medical evidence in favor of all defendants. The resolution of these two cases leaves 18 remaining lawsuits in Mississippi in which we have or may have an interest.

In 2011, the Special Master issued a ruling that a Jones Act employer defendant, such as us, cannot be sued for punitive damages, and this ruling has now been obtained in three of our cases. To date, seven of the 593 cases have gone to trial against defendants who allegedly manufactured or distributed drilling mud additives. None of these cases has involved an individual Jones Act employer, and we have not been a defendant in any of these cases. During the year ended December 31, 2013, a group of lawsuits premised on the same allegations as those in Mississippi were filed in Louisiana, 11 of which named one of our subsidiaries as a defendant. Four of these cases were dismissed through early motions, and seven claims remain pending in Louisiana. We intend to defend these lawsuits vigorously, although we can provide no assurance as to the outcome. We historically have maintained broad liability insurance, although we are not certain whether insurance will cover the liabilities, if any, arising out of these claims. Based on our evaluation of the exposure to date, we do not expect the liability, if any, resulting from these claims to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

One of our subsidiaries was involved in lawsuits arising out of the subsidiary's involvement in the design, construction and refurbishment of major industrial complexes. The operating assets of the subsidiary were sold and its operations discontinued in 1989, and the subsidiary has no remaining assets other than the insurance policies involved in its litigation, with its insurers and, either directly or indirectly through a qualified settlement fund. The subsidiary has been named as a defendant, along with numerous other companies, in lawsuits alleging bodily injury or personal injury as a result of exposure to asbestos. As of December 31, 2013, the subsidiary was a defendant in approximately 879 lawsuits, some of which include multiple plaintiffs, and we estimate that there are approximately 1,819 plaintiffs in these lawsuits. For many of these lawsuits, we have not been provided with sufficient information from the plaintiffs to determine whether all or some of the plaintiffs have claims against the subsidiary, the basis of any such claims, or the nature of their alleged injuries. The first of the asbestos-related lawsuits was filed against the subsidiary in 1990. Through December 31, 2013, the costs incurred to resolve claims, including both defense fees and expenses and settlement costs, have not been material, all known deductibles have been satisfied or are inapplicable, and the subsidiary's defense fees and expenses and settlement costs have been met by insurance made available to the subsidiary. The subsidiary continues to be named as a defendant in additional lawsuits, and we cannot predict the number of additional cases in which it may be named a defendant nor can we predict the potential costs to resolve such additional cases or to resolve the pending cases. However, the subsidiary has in excess of $1.0 billion in insurance limits potentially available to the subsidiary. Although not all of the policies may be fully available due to the insolvency of certain insurers, we believe that the subsidiary will have sufficient funding directly or indirectly from settlements and claims payments from insurers, assigned rights from insurers and coverage-in-place settlement agreements with insurers to respond to these claims. While we cannot predict or provide assurance as to the outcome of these matters, we do not believe that the ultimate liability, if any, arising from these claims will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Rio de Janeiro tax assessment—In the third quarter of 2006, we received tax assessments of BRL 407 million, equivalent to approximately $172 million, including interest and penalties, from the state tax authorities of Rio de Janeiro in Brazil against one of our Brazilian subsidiaries for taxes on equipment imported into the state in connection with our operations. The assessments resulted from a preliminary finding by these authorities that our record keeping practices were deficient. We currently believe that the substantial majority of these assessments are without merit. We filed an initial response with the Rio de Janeiro tax authorities on September 9, 2006 refuting these additional tax assessments. In September 2007, we received confirmation from the state tax authorities that they believe the additional tax assessments are valid, and as a result, we filed an appeal on September 27, 2007 to the state Taxpayer's Council contesting these assessments. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Brazilian import license assessment—In the fourth quarter of 2010, we received an assessment from the Brazilian federal tax authorities in Rio de Janeiro of BRL 509 million, equivalent to approximately $215 million, including interest and penalties, based upon the alleged failure to timely apply for import licenses for certain equipment and for allegedly providing improper information on import license applications. We believe that a substantial majority of the assessment is without merit and are vigorously pursuing legal remedies. The case was decided partially in favor of our Brazilian subsidiary in the lower administrative court level. The decision cancelled the majority of the assessment, reducing the total assessment to BRL 31 million, equivalent to approximately $13 million. On July 14, 2011, we filed an appeal to eliminate the assessment. On May 23, 2013, a ruling was issued that eliminated all assessment amounts. A further appeal by the taxing authorities is possible. While we cannot predict or provide assurance as to the outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Nigerian litigation—Under the Nigerian Industrial Training Fund Act of 2004, as amended (the "Nigerian Act"), Nigerian companies with five or more employees must remit on an annual basis one percent of their payroll to the Industrial Training Fund (the "ITF") established under the Nigerian Act to be used for the training of Nigerian nationals. We have not paid this amount on the cost of personnel movement to rigs or the expense of benefits to employees because "payroll" is not defined in the relevant legislation and we did not believe such costs should be considered "payroll" under the Nigerian Act. The ITF thereafter brought suit against our now-liquidated subsidiary, Sedco Forex Nigeria Limited, which subsequently filed preliminary objections, that were heard by the Lagos Federal High Court (the "Lagos Court") on October 28, 2013. The Lagos Court dismissed this lawsuit based on the objections and the statute of limitations. The ITF could still file an appeal, but to date, nothing has been filed. In a related matter, the ITF brought suit against our wholly-owned subsidiary, Transocean Support Services Nigeria Limited ("TSSNL"), which subsequently filed objections, but the judge has not yet issued a ruling.

In October 2013, Steven L. Newman, our chief executive officer, was named along with TSSNL in a criminal suit initiated by ITF for allegedly failing to provide the required training to TSSNL's employees. We do not believe that the criminal claim has any merit given that, among other things, Mr. Newman is neither an officer nor an employee of TSSNL. The criminal case is still pending, and we do not believe the resolution of this matter will have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

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

Other environmental matters

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

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

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

On February 24, 2011, the Housing Authority of the City of Los Angeles ("HACLA") filed an original complaint against multiple defendants for releases of hazardous substances and other hazardous materials based on prior use of a site it now owns between the late 1930s and 2008. HACLA seeks recovery for response costs and other damages resulting from the release of those hazardous substances and materials. On September 20, 2013, one of the third party defendants filed claims against one of our subsidiaries as a fourth party defendant asserting cost recovery and contribution under CERCLA, contribution pursuant to California Health and Safety Code, equitable contribution and indemnity and declaratory judgment. Our subsidiary never owned or leased the site, and our subsidiary's involvement at the site was primarily related to the demolition, excavation and grading of the site between 1979 and 1980. The remediation process is currently in the very initial stage and cannot be quantified, but we have no reason to believe at this time the ultimate liability, if any, will be material.

Resolutions of other claims by the EPA, the involved state agency or PRPs are at various stages of investigation. These investigations involve determinations of:

§ the actual responsibility attributed to us and the other PRPs at the site;

§ appropriate investigatory or remedial actions; and

§ allocation of the costs of such activities among the PRPs and other site users.

Our ultimate financial responsibility in connection with those sites may depend on many factors, including:

§ the volume and nature of material, if any, contributed to the site for which we are responsible;

§ the number of other PRPs and their financial viability; and

§ the remediation methods and technology to be used.

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

Retained risk

Overview—Our hull and machinery and excess liability insurance program is comprised of commercial market and captive insurance policies that we renew annually on May 1. We periodically evaluate our insurance limits and self-insured retentions. 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.

Hull and machinery coverage—At December 31, 2013, under the hull and machinery program, we generally maintain a $125 million per occurrence deductible, limited to a maximum of $200 million per policy period. Subject to the same shared deductible, we also have coverage for an amount equal to 50 percent of a rig’s insured value for combined costs incurred to mitigate damage to a rig and wreck removal. Any excess wreck removal costs are generally covered to the extent of our remaining excess liability coverage.

Excess liability coverage—At December 31, 2013, we carry $820 million of commercial market excess liability coverage, exclusive of deductibles and self-insured retention, noted below, which generally covers offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. Our excess liability coverage has (1) separate $10 million per occurrence deductibles on collision liability claims and (2) separate $5 million per occurrence deductibles on crew personal injury claims and on other third-party non-crew claims. Through our wholly owned captive insurance company, we have retained the risk of the primary

$50 million excess liability coverage. In addition, we generally retain the risk for any liability losses in excess of $870 million.

Other insurance coverage—At December 31, 2013, we also carry $100 million of additional insurance that generally covers expenses that would otherwise be assumed by the well owner, such as costs to control the well, redrill expenses and pollution from the well. This additional insurance provides coverage for such expenses in circumstances in which we have legal or contractual liability arising from our gross negligence or willful misconduct.

Letters of credit and surety bonds

At December 31, 2013 and 2012, we had outstanding letters of credit totaling $575 million and $522 million, respectively, issued under various committed and uncommitted credit lines provided by several banks to guarantee various contract bidding, performance activities and customs obligations, including letters of credit totaling $104 million and $113 million, respectively, that we agreed to maintain in support of the operations for Shelf Drilling (see Note 7—Discontinued Operations).

As is customary in the contract drilling business, we also have various surety bonds in place that secure customs obligations relating to the importation of our rigs and certain performance and other obligations. At December 31, 2013 and 2012, we had outstanding surety bonds totaling $6 million and $11 million, respectively.

Note 16—Redeemable Noncontrolling Interest

On October 18, 2007, one of our subsidiaries acquired a 50 percent interest in TPDI, a consolidated British Virgin Islands company formed to operate two Ultra-Deepwater Floaters, Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2. Quantum Pacific Management Limited ("Quantum") held the remaining 50 percent interest in TPDI. Through February 29, 2012, Quantum had the unilateral right, pursuant to a put option agreement, to exchange its 50 percent interest in TPDI for our shares or cash, at its election, at an amount based on an appraisal of the fair value of the drillships that are owned by TPDI, subject to certain adjustments. Accordingly, we presented Quantum's interest as redeemable noncontrolling interest on our consolidated balance sheets until Quantum exercised its rights under the put option agreement.

On February 29, 2012, Quantum exercised its rights under the put option agreement to exchange its interest in TPDI for our shares or cash, at its election. Based on the redemption value of Quantum's interest as of that date, we adjusted the carrying amount of the noncontrolling interest and reclassified Quantum's interest to other current liabilities with a corresponding adjustment of $106 million to retained earnings within shareholders' equity. We estimated the fair value of Quantum's interest using significant other observable inputs, representative of a Level 2 fair value measurement, including indications of market values of the drilling units owned by TPDI.

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

	Years ended December 31, 2012	2011
Redeemable noncontrolling interest		
Balance, beginning of period	$ 116	$ 41
Net income attributable to noncontrolling interest	13	78
Other comprehensive loss attributable to noncontrolling interest	—	(3)
Fair value adjustment to redeemable noncontrolling interest	106	—
Reclassification to accumulated other comprehensive loss	17	—
Reclassification to other current liabilities	(252)	—
Balance, end of period	$ —	$ 116

On March 29, 2012, Quantum elected to exchange its interest in TPDI for our shares, net of Quantum's share of TPDI's indebtedness, as defined in the put option agreement. Quantum had the right, prior to closing of this exchange, to change its election to cash, net of Quantum's share of TPDI's indebtedness.

Through settlement of the exchange transactions on May 31, 2012, we measured the carrying amount of Quantum's interest at its estimated fair value resulting in a cumulative adjustment of $25 million to increase the liability with corresponding adjustments to other expense on our consolidated statement of operations. On May 31, 2012, we issued 8.7 million shares to Quantum in a non-cash exchange for its interest in TPDI to satisfy our obligation, resulting in an adjustment of $134 million and $233 million to shares and additional paid-in capital, respectively. The adjustment included the extinguishment of the outstanding principal amount and unpaid interest associated with the TPDI Notes payable to Quantum (see Note 12—Debt). As a result of the transaction, TPDI became our wholly owned subsidiary.

Note 17—Shareholders' Equity

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

Share issuances—On May 31, 2012, we issued 8.7 million shares to Quantum in a non-cash exchange for its interest in TPDI. See Note 16—Redeemable Noncontrolling Interest.

In December 2011, we completed a public offering of 29.9 million shares at a price per share of $40.50, equivalent to CHF 37.19 using an exchange rate of USD 1.00 to CHF 0.9183. We received proceeds of $1.2 billion, net of underwriting discounts and commissions, issuance costs and the Swiss Federal Issuance Stamp Tax from the offering.

Shares held in treasury—In May 2009, at our annual general meeting, our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, which is equivalent to approximately $3.9 billion, using an exchange rate of USD 1.00 to CHF 0.89 as of the close of trading on December 31, 2013. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program.

During the years ended December 31, 2013, 2012 and 2011, we did not purchase any of our shares under our share repurchase program. At December 31, 2013 and 2012, we held 2.9 million shares in treasury, recorded at cost.

Shares held by subsidiary—One of our subsidiaries holds our shares for future use to satisfy our obligations to deliver shares in connection with awards granted under our incentive plans or other rights to acquire our shares. At December 31, 2013 and 2012, our subsidiary held 10.2 million shares and 11.5 million shares, respectively.

Accumulated other comprehensive loss—During the years ended December 31, 2013 and 2012, the changes in accumulated other comprehensive loss, presented net of tax, were as follows (in millions):

	Year ended December 31, 2013				Year ended December 31, 2012			
	Defined benefit pension plans	Derivative instruments	Marketable securities	Total	Defined benefit pension plans	Derivative instruments	Marketable securities	Total
Balance, beginning of period	$ (511)	$ (10)	$ —	$ (521)	$ (501)	$ 7	$ (2)	$ (496)
Other comprehensive income (loss) before reclassifications	202	(6)	—	196	(52)	1	—	(51)
Reclassifications to net income	45	18	—	63	42	(1)	2	43
Other comprehensive income (loss), net	247	12	—	259	(10)	—	2	(8)
Reclassification from redeemable noncontrolling interest	—	—	—	—	—	(17)	—	(17)
Balance, end of period	$ (264)	$ 2	$ —	$ (262)	$ (511)	$ (10)	$ —	$ (521)

Significant reclassifications from accumulated other comprehensive income to net income included the following (in millions):

	Statement of operations classification	Years ended December 31, 2013	2012	2011
Defined benefit pension plans				
Actuarial losses		$ 48	$ 45	$ 26
Prior service costs		—	(1)	(1)
Settlements and curtailments		1	3	—
Total amortization, before income taxes	Net periodic benefit costs (a)	49	47	25
Income tax (benefit) expense	Income tax expense	(4)	(5)	13
Total amortization, net of income taxes		$ 45	$ 42	$ 38

(a) We recognize the amortization of accumulated other comprehensive income components related to defined benefit pension plans in net periodic benefit costs. In the year ended December 31, 2013, the amortization components of our net periodic benefit costs were $37 million, recorded in operating and maintenance costs, and $12 million, recorded in general and administrative costs. In the year ended December 31, 2012, the amortization components of our net periodic benefit costs were $31 million, recorded in operating and maintenance costs, and $16 million, recorded in general and administrative costs. In the year ended December 31, 2011, the amortization components of our net periodic benefit costs were $17 million, recorded in operating and maintenance costs, and $8 million, recorded in general and administrative costs. See Note 14—Postemployment Benefit Plans.

Note 18—Share-Based Compensation Plans

Overview—We have (i) a long-term incentive plan (the "Long-Term Incentive Plan") for executives, key employees and outside directors under which awards can be granted in the form of deferred units, restricted shares, stock options, stock appreciation rights and cash performance awards and (ii) other incentive plans under which awards are currently outstanding. Awards that may be granted under the Long-Term Incentive Plan include time-vesting awards ("time-based awards") and awards that are earned based on the achievement of certain performance criteria ("performance-based awards") or market factors ("market-based awards"). Our executive compensation committee of our board of directors determines the terms and conditions of the awards granted under the Long-Term Incentive Plan. As of December 31, 2013, we had 36.0 million shares authorized and 7.9 million shares available to be granted under the Long-Term Incentive Plan.

Time-based awards typically vest either in three equal annual installments beginning on the first anniversary date of the grant or in an aggregate installment at the end of the stated vesting period. Performance-based and market-based awards are typically awarded subject to either a two-year or a three-year measurement period during which the number of options, shares or deferred units remains uncertain. At the end of the measurement period, the awarded number of options, shares or deferred units is determined (the "determination date") subject to the stated vesting period. The performance-based and market-based awards generally vest in one aggregate installment following the determination date. Once vested, stock options and stock appreciation rights generally have a 10-year term during which they are exercisable.

As of December 31, 2013, total unrecognized compensation costs related to all unvested share-based awards were $93 million, which are expected to be recognized over a weighted-average period of 1.7 years. In the years ended December 31, 2013, 2012 and 2011, we recognized additional share-based compensation expense of $22 million, $4 million and $3 million, respectively, in connection with modifications of share-based awards.

Option valuation assumptions—We estimated the fair value of each option award under the Long-Term Incentive Plan on the grant date using the Black-Scholes-Merton option-pricing model with the following weighted-average assumptions:

	Years ended December 31,		
	2013	2012	2011
Dividend yield	2%	—	4%
Expected price volatility	39%	43%	40%
Risk-free interest rate	0.94%	0.87%	1.97%
Expected life of options	5.3 years	5.0 years	4.9 years
Weighted-average fair value of options granted	$ 17.37	$ 18.87	$ 19.75

Time-based awards

Deferred units—A deferred unit is a unit that is equal to one share but has no voting rights until the underlying shares are issued. The following table summarizes unvested activity for time-based vesting deferred units ("time-based units") granted under our incentive plans during the year ended December 31, 2013:

	Number of units		Weighted-average grant-date fair value per share
Unvested at January 1, 2013	2,870,051	$	58.09
Granted	1,691,029		58.91
Vested	(1,556,840)		61.32
Forfeited	(271,912)		57.28
Unvested at December 31, 2013	2,732,328	$	56.84

The total grant-date fair value of the time-based units that vested during the year ended December 31, 2013 was $95 million.

There were 2,183,853 and 1,090,747 time-based units granted during the years ended December 31, 2012 and 2011, respectively. The weighted-average grant-date fair value of time-based units granted was $50.07 and $77.55 per share for the years ended December 31, 2012 and 2011, respectively. There were 1,064,359 and 832,252 time-based units that vested during the years ended December 31, 2012 and 2011, respectively. The total grant-date fair value of the time-based units that vested was $74 million and $66 million for the years ended December 31, 2012 and 2011, respectively.

Restricted shares—We did not grant time-based vesting restricted shares ("time-based shares") during the years ended December 31, 2013, 2012 and 2011. There were no time-based shares that vested during the years ended December 31, 2013 and 2012. There were 3,939 time-based shares that vested during the year ended December 31, 2011. The total grant-date fair value of time-based shares that vested was $1 million for the year ended December 31, 2011.

Stock options—The following table summarizes activity for vested and unvested time-based vesting stock options ("time-based options") outstanding under our incentive plans during the year ended December 31, 2013:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2013	1,616,055	$ 71.69	6.30	$ —
Granted	455,915	59.30		
Exercised	(102,254)	36.64		
Forfeited	(102,973)	56.97		
Expired	(12,579)	27.15		
Outstanding at December 31, 2013	1,854,164	$ 71.49	6.55	$ —
Vested and exercisable at December 31, 2013	1,176,140	$ 79.25	5.32	$ —

The weighted-average grant-date fair value of time-based options granted during the year ended December 31, 2013 was $17.37 per time-based option. The total grant-date fair value of time-based options that vested during the year ended December 31, 2013 was $7 million. The total pre-tax intrinsic value of time-based options exercised during the year ended December 31, 2013 was $5 million. At January 1 and December 31, 2013, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on these dates. There were unvested time-based options to purchase 678,024 shares as of December 31, 2013.

There were time-based options to purchase 395,673 and 194,342 shares granted during the years ended December 31, 2012 and 2011, respectively. The weighted-average grant-date fair value of time-based options granted was $18.87 and $19.75 per time-based option for the years ended December 31, 2012 and 2011, respectively. The total grant-date fair value of time-based options that vested was $5 million and $8 million for the years ended December 31, 2012 and 2011, respectively. There were time-based options to purchase 264,707 and 210,997 shares exercised during the years ended December 31, 2012 and 2011, respectively. The total pretax intrinsic value of time-based options exercised was $3 million and $5 million during the years ended December 31, 2012 and 2011, respectively.

Stock appreciation rights—The following table summarizes activity for stock appreciation rights outstanding under our incentive plans during the year ended December 31, 2013:

	Number of awards	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2013	187,739	$ 93.39	3.76	$ —
Outstanding at December 31, 2013	187,739	$ 93.39	2.76	$ —
Vested and exercisable at December 31, 2013	187,739	$ 93.39	2.76	$ —

We did not grant stock appreciation rights during the years ended December 31, 2013, 2012, and 2011. At January 1 and December 31, 2013, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on those dates. There were no stock appreciation rights exercised for the years ended December 31, 2013 and 2012. There were 1,400 stock appreciation rights exercised with a total pre-tax intrinsic value of zero for the year ended December 31, 2011. There were no unvested stock appreciation rights outstanding as of December 31, 2013.

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Market-based awards

Deferred units—We grant market-based deferred units ("market-based units") that can be earned depending on the achievement of certain market conditions. The number of units earned is quantified upon completion of the specified period at the determination date. The following table summarizes unvested activity for market-based units granted under our incentive plans during the year ended December 31, 2013:

	Number of units	Weighted-average grant-date fair value per share
Unvested at January 1, 2013	231,451	$ 65.50
Granted	171,001	74.05
Vested	(78,136)	78.69
Forfeited	(18,153)	69.87
Unvested at December 31, 2013	306,163	$ 66.65

Total grant date fair value of the market-based units that vested during the year ended December 31, 2013 was $6 million.

There were 163,319 and 98,797 market-based units granted during the years ended December 31, 2012 and 2011 with a weighted-average grant-date fair value of $58.52 and $78.69 per share, respectively. The total grant-date fair value of the market-based units that vested was $24 million for the year ended December 31, 2012. No market-based units vested in the year ended December 31, 2011.

Performance-based awards

Stock options—We have previously granted performance-based stock options ("performance-based options") that could be earned depending on the achievement of certain performance targets. The number of options earned is quantified upon completion of the performance period at the determination date. The following table summarizes activity for vested and unvested performance-based options outstanding under our incentive plans during the year ended December 31, 2013:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2013	179,262	$ 75.30	3.22	$ —
Exercised	(7,385)	22.58		
Outstanding at December 31, 2013	171,877	$ 77.57	2.28	$ —
	171,877	$ 77.57	2.28	$ —

Vested and exercisable at December 31, 2013

We did not grant performance-based options during the years ended December 31, 2013, 2012 and 2011. At January 1 and December 31, 2013, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on that date. There were no performance-based options exercised during the years ended December 31, 2012 and 2011. There were no unvested performance-based stock options outstanding as of December 31, 2013.

Note 19—Supplemental Balance Sheet Information

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

	December 31, 2013	December 31, 2012
Other current liabilities		
Accrued payroll and employee benefits	$ 431	$ 421
Distribution payable	202	—
Deferred revenue	195	214
Deferred revenue of consolidated variable interest entities	21	21
Accrued taxes, other than income	145	150
Accrued interest	108	122
Contingent liabilities	490	1,958
Macondo well incident settlement obligations	460	—
Other	20	47
Total other current liabilities	$ 2,072	$ 2,933

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

	December 31, 2013	December 31, 2012
Other long-term liabilities		
Long-term income taxes payable	$ 502	$ 581
Accrued pension liabilities	339	558
Deferred revenue	108	174
Deferred revenue of consolidated variable interest entities	51	72
Drilling contract intangibles	44	60
Accrued retiree life insurance and medical benefits	49	54
Macondo well incident settlement obligations	380	—
Other	81	105
Total other long-term liabilities	$ 1,554	$ 1,604

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Note 20—Supplemental Cash Flow Information

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

	Years ended December 31, 2013	2012	2011
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable	$ 58	$ (139)	$ (174)
Increase in other current assets	(152)	(73)	(73)
Decrease in other assets	87	12	26
Increase (decrease) in accounts payable and other current liabilities	(625)	931	978
Decrease in other long-term liabilities	(33)	(63)	(34)
Change in income taxes receivable / payable, net	(151)	(156)	80
	$ (816)	$ 512	$ 803

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

	Years ended December 31, 2013	2012	2011
Certain cash operating activities			
Cash payments for interest	$ 669	$ 719	$ 501
Cash payments for income taxes	457	347	338
Non-cash investing and financing activities			
Capital expenditures, accrued at end of period (a)	$ 167	$ 123	$ 62
Issuance of shares in exchange for noncontrolling interest (b)	—	367	—
Non-cash proceeds received for the sale of assets (c)	—	194	—

(a)

These amounts represent additions to property and equipment for which we had accrued a corresponding liability in accounts payable.

(b) On May 31, 2012, we issued 8.7 million shares to Quantum in a non-cash exchange for its interest in TPDI. See Note 16—Redeemable Noncontrolling Interest.

(c) During the year ended December 31, 2012, we completed the sale of 38 drilling units to Shelf Drilling. In connection with the sale transactions, we received net cash proceeds of $568 million and non-cash proceeds in the form of preference shares with an aggregate stated value of $195 million. We recognized the preference shares at their estimated fair value measured at the time of the sale, in the aggregate amount of $194 million, including the fair value associated with the embedded derivatives. See Note 7—Discontinued Operations.

Note 21—Financial Instruments

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

	December 31, 2013		December 31, 2012	
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and cash equivalents	$ 3,243	$ 3,243	$ 5,134	$ 5,134
Notes and other loans receivable	101	101	142	142
Preference shares	—	—	196	196
Restricted cash investments	624	649	861	903
Long-term debt, including current maturities	10,539	11,621	12,268	13,899
Long-term debt of consolidated variable interest entities, including current maturities	163	163	191	191
Derivative instruments, assets	—	—	8	8
Derivative instruments, liabilities	—	—	15	15

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

Cash and cash equivalents—The carrying amount of cash and cash equivalents represents the historical cost, plus accrued interest, which approximates fair value because of the short maturities of those instruments. We measured the estimated fair value of our cash equivalents using significant other observable inputs, representative of a Level 2 fair value measurement, including the net asset values of the investments. At December 31, 2013 and 2012, the aggregate carrying amount of our cash equivalents was $2.3 billion and $4.2 billion, respectively.

Notes and other loans receivable—We hold certain notes and other loans receivable, which originated in connection with certain asset dispositions and supplier advances. The carrying amount represents the amortized cost of our investments. We measured the estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including the credit ratings of the borrowers. At December 31, 2013, the aggregate carrying amount of our notes receivable and other loans receivable was $101 million, including $6 million and $95 million recorded in other current assets and other assets, respectively. At December 31, 2012, the aggregate carrying amount of our notes receivable and other loans receivable was $142 million, including $35 million and $107 million, recorded in other current assets and other assets, respectively.

Preference shares—We held preference shares of one of Shelf Drilling's parent companies. The carrying amount of the preference shares represents the historical cost of our investment, as the preference shares do not have a readily determinable fair value. We measured the estimated fair value of the Shelf Drilling preference shares using significant unobservable inputs, representative of a Level 3 fair value measurement, including the credit ratings and financial position of the investee. At December 31, 2012, the aggregate carrying amount of the preference shares, excluding the balance associated with the embedded derivatives, was $196 million recorded in other assets. In June 2013, we sold the preference shares to an unaffiliated party for cash proceeds of $185 million.

Restricted cash investments—The carrying amount of the Eksportfinans Restricted Cash Investments represents the amortized cost of our investment. We measured the estimated fair value of the Eksportfinans Restricted Cash Investments using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads of the instruments. At December 31, 2013 and 2012, the aggregate carrying amount of the Eksportfinans Restricted Cash Investments was $594 million and $801 million, respectively. At December 31, 2013 and 2012, the estimated fair value of the Eksportfinans Restricted Cash Investments was $619 million and $843 million, respectively.

The carrying amount of the restricted cash investments for the TPDI Credit Facilities, the ADDCL Credit Facilities and other obligations approximates fair value due to the short term nature of the instruments in which the restricted cash investments are held. At December 31, 2013, the aggregate carrying amount of the restricted cash investments for the ADDCL Credit Facilities and other obligations was $30 million. At December 31, 2012, the aggregate carrying amount of the restricted cash investments for the TPDI Credit Facilities, the ADDCL Credit Facilities and other obligations was $60 million.

Debt—We measured the estimated fair value of our fixed-rate debt using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads for the instruments. At December 31, 2013 and 2012, the aggregate carrying amount of our fixed-rate debt was $10.5 billion and $11.7 billion, respectively. At December 31, 2013 and 2012, the aggregate estimated fair value of our fixed-rate debt was $11.6 billion and $13.3 billion, respectively.

The carrying amount of our variable-rate debt approximates fair value because the terms of those debt instruments include short-term interest rates and exclude penalties for prepayment. We measured the estimated fair value of our variable-rate debt using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads for the instruments. At December 31, 2013, we did not have any variable-rate debt. At December 31, 2012, the aggregate carrying amount of our variable-rate debt was $579 million.

Debt of consolidated variable interest entities—The carrying amount of the variable-rate debt of our consolidated variable interest entities approximates fair value because the terms of those debt instruments include short-term interest rates and exclude penalties for prepayments. We measured the estimated fair value of the debt of our consolidated variable interest entities using significant other observable inputs, representative of a Level 2 fair value measurement, including the terms and credit spreads of the instruments. At December 31, 2013 and 2012, the aggregate carrying amount of the variable-rate debt of our consolidated variable interest entities was $163 million and $191 million, respectively.

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

Note 22—Risk Concentration

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

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

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

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

We do not enter into currency exchange derivative transactions for speculative purposes. We record designated currency exchange derivative instruments at fair value and defer gains and losses in other comprehensive income, recognizing the gains and losses when the underlying currency exchange exposure is realized. We record undesignated currency exchange derivative instruments at fair value and record changes to the fair value in current period earnings as an adjustment to currency exchange gains or losses. At December 31, 2012, we had cross-currency swaps that were designated as cash flow hedges of certain debt instruments denominated in Norwegian kroner. In March 2013, we terminated these cross-currency interest rate swaps and the underlying debt instruments. See Note 13—Derivatives and Hedging.

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

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

We derive the majority of our revenue from services to international oil companies, government-owned oil companies and government-controlled oil companies. Receivables are dispersed in various countries (see Note 23—Operating Segments, Geographic Analysis and Major Customers). We establish an allowance for doubtful accounts on a case-by-case basis, considering changes in the financial position of a customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. Although we have encountered isolated credit concerns related to independent oil companies, we are not aware of any significant credit risks related to our customer base and do not generally require collateral or other security to support customer receivables.

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

Labor agreements—We require highly skilled personnel to operate our drilling units. We conduct extensive personnel recruiting, training and safety programs. At December 31, 2013, we had approximately 15,100 employees, including approximately 1,000 persons engaged through contract labor providers. Of our 15,100 employees, approximately 800 persons are 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.

Note 23—Operating Segments, Geographic Analysis and Major Customers

Operating segments—We have established two operating segments: (1) contract drilling services and (2) drilling management services. Our contract drilling services business operates in a single, global market for the provision of contract drilling services. The location of our rigs and the allocation of our resources to build or upgrade rigs are determined by the activities and needs of our customers. Our drilling management services operating segment does not meet the quantitative thresholds for determining reportable segments.

Geographic analysis—Operating revenues for our continuing operations by country were as follows (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.

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

	December 31,	
	2013	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.

A substantial portion of our assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the revenues generated by such assets during the periods. Although we are organized under the laws of Switzerland, we do not conduct any operations and do not have operating revenues in Switzerland. At December 31, 2013 and 2012, the aggregate carrying amount of our long-lived assets located in Switzerland was $6 million and $7 million, respectively.

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

Major customers—For the year ended December 31, 2013, Chevron Corporation and BP accounted for approximately 12 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. For the year ended December 31, 2012, Chevron Corporation, BP and Petrobras accounted for approximately 11 percent, 11 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. For the year ended December 31, 2011, BP accounted for approximately 11 percent of our consolidated operating revenues from continuing operations.

Note 24—Condensed Consolidating Financial Information

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

The following tables present condensed consolidating financial information for (a) Transocean Ltd. (the "Parent Guarantor"), (b) Transocean Inc. (the "Subsidiary Issuer"), and (c) the other direct and indirect wholly owned and partially owned subsidiaries of the Parent Guarantor, none of which guarantee any indebtedness of the Subsidiary Issuer (the "Other Subsidiaries"). The tables include the consolidating adjustments necessary to present the condensed financial statements on a consolidated basis. The condensed consolidating financial information may not necessarily be indicative of the results of operations, financial position or cash flows had the subsidiaries operated as independent entities.

	Year ended December 31, 2013				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ 18	$ —	$ 9,468	$ (2)	$ 9,484
Cost and expenses	47	9	7,132	(2)	7,186
Loss on impairment	—	—	(81)	—	(81)
Gain on disposal of assets, net	—	—	7	—	7
Operating income (loss)	(29)	(9)	2,262	—	2,224
Other income (expense), net					
Interest income (expense), net	(15)	(538)	21	—	(532)
Equity in earnings	1,450	2,112	—	(3,562)	—
Other, net	1	(15)	(14)	—	(28)
	1,436	1,559	7	(3,562)	(560)
Income from continuing operations before income tax expense	1,407	1,550	2,269	(3,562)	1,664
Income tax expense	—	—	258	—	258
Income from continuing operations	1,407	1,550	2,011	(3,562)	1,406
	—	(97)	98	—	1

Gain (loss) from discontinued operations, net of tax					
Net Income	1,407	1,453	2,109	(3,562)	1,407
Net income attributable to noncontrolling interest	—	—	—	—	—
Net income attributable to controlling interest	1,407	1,453	2,109	(3,562)	1,407
Other comprehensive income before income taxes	3	238	19	—	260
Income taxes related to other comprehensive loss	—	—	2	—	2
Other comprehensive income, net of income taxes	3	238	21	—	262
Total comprehensive income	1,410	1,691	2,130	(3,562)	1,669
Total comprehensive income attributable to noncontrolling interest		—	3	—	3
Total comprehensive income attributable to controlling interest	$ 1,410	$ 1,691	$ 2,127	$ (3,562)	$ 1,666

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	Year ended December 31, 2012				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ 5	$ 9,213	$ (22)	$ 9,196
Cost and expenses	54	16	7,463	(22)	7,511
Loss on impairment	—	—	(140)	—	(140)
Gain on disposal of assets, net	—	—	36	—	36
Operating income (loss)	(54)	(11)	1,646	—	1,581
Other income (expense), net					
Interest expense, net	(12)	(576)	(79)	—	(667)
Equity in earnings	(153)	402	—	(249)	—
Other, net	—	(4)	(44)	—	(48)
	(165)	(178)	(123)	(249)	(715)
Income (loss) from continuing operations before income tax expense	(219)	(189)	1,523	(249)	866
Income tax expense	—	—	50	—	50
Income (loss) from continuing operations	(219)	(189)	1,473	(249)	816
Loss from discontinued operations, net of tax	—	—	(1,027)	—	(1,027)
Net income (loss)	(219)	(189)	446	(249)	(211)
Net income attributable to noncontrolling interest	—	—	8	—	8
Net income (loss) attributable to controlling interest	(219)	(189)	438	(249)	(219)
Other comprehensive income (loss) before income taxes	(5)	(31)	35	—	(1)
Income taxes related to other comprehensive loss	—	—	(7)	—	(7)
Other comprehensive income (loss), net of income taxes	(5)	(31)	28	—	(8)
Total comprehensive income (loss)	(224)	(220)	474	(249)	(219)
Total comprehensive income attributable to noncontrolling interest	—	—	8	—	8

Total comprehensive income (loss) attributable to controlling interest	$ (224)	$ (220)	$ 466	$ (249)	$ (227)

	Year ended December 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 8,045	$ (18)	$ 8,027
Cost and expenses	44	4	7,546	(18)	7,576
Loss on impairment	—	—	(5,201)	—	(5,201)
Loss on disposal of assets, net	—	—	(12)	—	(12)
Operating loss	(44)	(4)	(4,714)	—	(4,762)
Other income (expense), net					
Interest expense, net	(11)	(510)	(56)	—	(577)
Equity in earnings	(5,699)	(5,174)	—	10,873	—
Other, net	—	9	(108)	—	(99)
	(5,710)	(5,675)	(164)	10,873	(676)
Loss from continuing operations before income tax expense	(5,754)	(5,679)	(4,878)	10,873	(5,438)
Income tax expense	—	—	324	—	324
Loss from continuing operations	(5,754)	(5,679)	(5,202)	10,873	(5,762)
Income from discontinued operations, net of tax	—	—	85	—	85
Net loss	(5,754)	(5,679)	(5,117)	10,873	(5,677)
Net income attributable to noncontrolling interest	—	—	77	—	77
Net loss attributable to controlling interest	(5,754)	(5,679)	(5,194)	10,873	(5,754)
Other comprehensive loss before income taxes	(3)	(114)	(64)	—	(181)
Income taxes related to other comprehensive loss	—	—	13	—	13
Other comprehensive loss, net of income taxes	(3)	(114)	(51)	—	(168)
Total comprehensive loss	(5,757)	(5,793)	(5,168)	10,873	(5,845)
Total comprehensive income attributable to noncontrolling interest	—	—	73	—	73
Total comprehensive loss attributable to controlling interest	$ (5,757)	$ (5,793)	$ (5,241)	$ 10,873	$ (5,918)

	December 31, 2013				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 4	$ 1,617	$ 1,622	$ —	$ 3,243
Other current assets	22	1,302	4,607	(2,402)	3,529
Total current assets	26	2,919	6,229	(2,402)	6,772
Property and equipment, net	—	—	21,707	—	21,707
Goodwill	—	—	2,987	—	2,987
Investment in affiliates	18,151	31,308	—	(49,459)	—
Other assets	—	2,427	19,954	(21,301)	1,080
Total assets	18,177	36,654	50,877	(73,162)	32,546
Liabilities and equity					
Debt due within one year	—	—	323	—	323
Other current liabilities	214	526	4,893	(2,402)	3,231
Total current liabilities	214	526	5,216	(2,402)	3,554
Long-term debt	1,237	18,759	11,684	(21,301)	10,379
Other long-term liabilities	35	232	1,661	—	1,928
Total long-term liabilities	1,272	18,991	13,345	(21,301)	12,307
Commitments and contingencies					
Total equity	16,691	17,137	32,316	(49,459)	16,685
Total liabilities and equity	$ 18,177	$ 36,654	$ 50,877	$ (73,162)	$ 32,546

	December 31, 2012				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 24	$ 3,155	$ 1,955	$ —	$ 5,134
Other current assets	7	1,901	3,852	(2,247)	3,513
Total current assets	31	5,056	5,807	(2,247)	8,647
Property and equipment, net	—	—	20,880	—	20,880
Goodwill	—	—	2,987	—	2,987
Investment in affiliates	16,354	27,933	—	(44,287)	—
Other assets	—	1,804	18,244	(18,307)	1,741

Total assets	16,385	34,793	47,918	(64,841)	34,255
Liabilities and equity					
Debt due within one year	—	564	803	—	1,367
Other current liabilities	13	632	5,698	(2,247)	4,096
Total current liabilities	13	1,196	6,501	(2,247)	5,463
Long-term debt	594	17,772	11,033	(18,307)	11,092
Other long-term liabilities	33	454	1,483	—	1,970
Total long-term liabilities	627	18,226	12,516	(18,307)	13,062
Commitments and contingencies					
Total equity	15,745	15,371	28,901	(44,287)	15,730
Total liabilities and equity	$ 16,385	$ 34,793	$ 47,918	$ (64,841)	$ 34,255

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

	Year ended December 31, 2012				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (86)	$ (953)	$ 3,747	$ —	$ 2,708
Cash flows from investing activities					
Capital expenditures	—	—	(1,303)	—	(1,303)
Capital expenditures for discontinued operations	—	—	(106)	—	(106)
Proceeds from disposal of assets, net	—	—	191	—	191
Proceeds from disposal of discontinued operations, net	—	568	221	—	789
Investing activities with affiliates, net	(165)	(2,344)	(3,726)	6,235	—
Other, net	—	29	11	—	40
Net cash provided by (used in) investing activities	(165)	(1,747)	(4,712)	6,235	(389)
Cash flows from financing activities					
Changes in short-term borrowings, net	—	—	(260)	—	(260)
Proceeds from debt	—	1,493	—	—	1,493
Repayments of debt	—	(1,689)	(593)	—	(2,282)
Proceeds from restricted cash investments	—	—	311	—	311
Deposits to restricted cash investments	—	—	(167)	—	(167)
Distribution of qualifying additional paid-in capital	(276)	—	—	—	(276)
Financing activities with affiliates, net	549	3,276	2,410	(6,235)	—
Other, net	(1)	(18)	(2)	—	(21)
Net cash provided by (used in) financing activities	272	3,062	1,699	(6,235)	(1,202)
Net increase (decrease) in cash and cash equivalents	21	362	734	—	1,117
Cash and cash equivalents at beginning of period	3	2,793	1,221	—	4,017
Cash and cash equivalents at end of period	$ 24	$ 3,155	$ 1,955	$ —	$ 5,134

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	Year ended December 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (52)	$ (568)	$ 2,445	$ —	$ 1,825
Cash flows from investing activities					
Capital expenditures	—	—	(974)	—	(974)
Capital expenditures for discontinued operations	—	—	(46)	—	(46)
Investment in business combination, net of cash acquired	—	—	(1,246)	—	(1,246)
Proceeds from disposal of assets, net	—	—	14	—	14
Proceeds from disposal of discontinued operations, net	—	—	447	—	447
Investing activities with affiliates, net	(875)	(325)	(1,764)	2,964	—
Other, net	—	(23)	(68)	—	(91)
Net cash provided by (used in) investing activities	(875)	(348)	(3,637)	2,964	(1,896)
Cash flows from financing activities					
Changes in short-term borrowings, net	—	(88)	—	—	(88)
Proceeds from debt	435	2,504	—	—	2,939
Repayments of debt	(429)	(1,827)	(153)	—	(2,409)
Proceeds from restricted cash investments	429	—	50	—	479
Deposits to restricted cash investments	(435)	—	(88)	—	(523)
Proceeds from share issuance, net	1,211	—	—	—	1,211
Distribution of qualifying additional paid-in capital	(759)	—	—	—	(759)
Financing activities with affiliates, net	495	1,114	1,355	(2,964)	—
Other, net	(55)	(35)	(26)	—	(116)
	892	1,668	1,138	(2,964)	734

Net cash provided by (used in) financing activities					
Net increase (decrease) in cash and cash equivalents	(35)	752	(54)	—	663
Cash and cash equivalents at beginning of period	38	2,041	1,275	—	3,354
Cash and cash equivalents at end of period	$ 3	$ 2,793	$ 1,221	$ —	$ 4,017

Note 25—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. See Note 16—Redeemable Noncontrolling Interest.

Note 26—Quarterly Results (Unaudited)

	Three months ended March 31,	Three months ended June 30,	Three months ended September 30,	Three months ended December 31,
	(In millions, except per share data)			
2013				
Operating revenues	$ 2,197	$ 2,397	$ 2,558	$ 2,332
Operating income (a)	473	602	742	407
Income from continuing operations (a)	313	321	544	228
Net income (a) (b)	329	303	544	231
Net income attributable to controlling interest (a) (b)	321	307	546	233
Per share earnings from continuing operations				
Basic	$ 0.88	$ 0.87	$ 1.49	$ 0.62
Diluted	$ 0.88	$ 0.87	$ 1.49	$ 0.62
Weighted-average shares outstanding				
Basic	360	360	361	361
Diluted	360	360	361	361
2012				
Operating revenues	$ 2,110	$ 2,329	$ 2,431	$ 2,326
Operating income (loss) (c)	371	(142)	811	541
Income (loss) from continuing operations (c)	154	(303)	533	432
Net income (loss) (c) (d)	18	(303)	(383)	457
Net income (loss) attributable to controlling interest (c) (d)	10	(304)	(381)	456
Per share earnings (loss) from continuing operations				
Basic	$ 0.42	$ (0.86)	$ 1.49	$ 1.19
Diluted	$ 0.42	$ (0.86)	$ 1.49	$ 1.19
Weighted-average shares outstanding				
Basic	350	353	359	359
Diluted	350	353	359	360

(a) First quarter and third quarter included losses of $74 million and $29 million, respectively, associated with loss contingencies related to Macondo well incident. Second quarter included an aggregate loss of $37 million associated with the impairment of certain drilling units classified as assets held for sale. Third quarter included a gain of $33 million associated with the sale of Transocean Richardson. See Note 5—Impairments, Note 10—Drilling Fleet and Note 15-Commitments and Contingencies.

(b) First, second, third and fourth quarters included aggregate gains of $15 million, $3 million, $31 million and $5 million, respectively, associated with the disposal of assets of our discontinued operations. See Note 7—Discontinued Operations.

(c) First quarter included an adjustment of $118 million associated with an adjustment to the goodwill impairment attributed to our contract drilling services reporting unit and a loss of $22 million associated with the impairment of the customer relationships intangible asset related to the U.K. operations of our drilling management services reporting unit. Second quarter included a loss of $756 million associated with loss contingencies related to the Macondo well incident. Third quarter included an aggregate gain of $51 million associated with the sale of Discoverer 534 and Jim Cunningham. See Note 5—Impairments, Note 10—Drilling Fleet and Note 15—Commitments and Contingencies.

(d) First, second, third and fourth quarters included aggregate losses of $93 million, $12 million, $878 million and $3 million, respectively, associated with the impairment of assets of our discontinued operations. First, second, third and fourth quarters included aggregate gains (losses) of $(1) million, $72 million, $(1) million and $12 million, respectively, associated with the disposal of assets of our discontinued operations. See Note 7—Discontinued Operations.

Note 27—Subsequent Events

Income Taxes—Subsequent to December 31, 2013, 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.

Discontinued operations—Subsequent to December 31, 2013, in connection with our efforts to discontinue non-strategic operations, we completed the sale of ADTI, which performs drilling management services in the North Sea. 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.

Debt—Subsequent to December 31, 2013, we repaid borrowings of $163 million outstanding under the ADDCL Credit Facilities. Upon repayment of all borrowings, we terminated the bank credit agreement under which the credit facilities were established.

Note 28—Supplemental Disclosures Required by Swiss Law

Personnel expenses—In the years ended December 31, 2013, 2012 and 2011, we recognized total personnel expenses of $2.6 billion, $2.5 billion, and $2.6 billion, respectively.

Fire insurance—At December 31, 2013 and 2012, the fire insurance value of our property and equipment was $27.2 billion and $29.3 billion, respectively.

Compensation and security ownership of board members and executive officers—In the Transocean Ltd. statutory financial statements, we have presented the compensation and security ownership of members of our board of directors and members of our executive management team. See Transocean Ltd. Statutory Financial Statements—Notes to Statutory Financial Statements—Note 6—Share Ownership, Note 7—Board of Directors' Compensation, and Note 8—Executive Management Team Compensation.

Risk assessment—In the Transocean Ltd. statutory financial statements, we have presented our risk assessment. See Transocean Ltd. Statutory Financial Statements—Notes to Statutory Financial Statements—Note 13—Risk Assessment.

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

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

Item 9A. Controls and Procedures

Disclosure controls and procedures—We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures, as defined in the Exchange Act, Rules 13a-15 and 15d-15, were effective as of December 31, 2013 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms.

Internal controls over financial reporting—There were no changes to our internal controls during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

See "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" included in Item 8 of this Annual Report.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 11. Executive Compensation

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

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

Item 14. Principal Accounting Fees and Services

The information required by Items 10, 11, 12, 13 and 14 is incorporated herein by reference to our definitive proxy statement for our 2014 annual general meeting of shareholders, which will be filed with the U.S. Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of December 31, 2013. Certain information with respect to our executive officers is set forth in Item 4 of this annual report under the caption “Executive Officers of the Registrant.”

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – continued

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Financial Statements

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

(2) Financial Statement Schedules

Transocean Ltd. and Subsidiaries
Schedule II - Valuation and Qualifying Accounts
(In millions)

		Additions			
	Balance at beginning of period	Charge to cost and expenses	Charge to other accounts -describe	Deductions -describe	Balance at end of period
Year ended December 31, 2011					
Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 38	$ —	$ —	$ 10(a)	$ 28
Allowance for obsolete materials and supplies	70	5	—	2(b)	73
Valuation allowance on deferred tax assets	164	19	—	—	183
Year ended December 31, 2012					

Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 28	$ —	$ —	$ 8(a)	$ 20
Allowance for obsolete materials and supplies	73	8	—	15(b)	66
Valuation allowance on deferred tax assets	183	28	—	1(c)	210
Year ended December 31, 2013					
Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 20	$ —	$ —	$ 6(a)	$ 14
Allowance for obsolete materials and supplies	66	17	—	3(b)	80
Valuation allowance on deferred tax assets	210	37	—	—	247

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

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

(c) Primarily due to reassessments of valuation allowances against future operations.

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

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – continued

(3) Exhibits

The following exhibits are filed in connection with this Report:

Number	Description
3.1	Articles of Association of Transocean Ltd. (incorporated by reference to Exhibit 3.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on August 22, 2013)
3.2	Organizational Regulations of Transocean Ltd. (incorporated by reference to Exhibit 3.2 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2012)
4.1	Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.2	First Supplemental Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee, supplementing the Indenture dated as of April 15, 1997 (incorporated by reference to Exhibit 4.2 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.3	Second Supplemental Indenture dated as of May 14, 1999 between Transocean Offshore (Texas) Inc., Transocean Offshore Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Transocean Offshore Inc.'s Post-Effective Amendment No. 1 to Registration Statement on Form S-3 (Registration No. 333-59001-99))
4.4	Third Supplemental Indenture dated as of May 24, 2000 between Transocean Sedco Forex Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Sedco Forex Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on May 24, 2000)
4.5	Fourth Supplemental Indenture dated as of May 11, 2001 between Transocean Sedco Forex Inc. and The Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Quarterly Report on Form 10-Q (Commission File No. 333-75899) for the quarter ended March 31, 2001)
4.6	Fifth Supplemental Indenture, dated as of December 18, 2008, among Transocean Ltd., Transocean Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.4 to Transocean Ltd.'s Current Report on Form 8-K filed on December 19, 2008)
4.7	Form of 7.45% Notes due April 15, 2027 (incorporated by reference to Exhibit 4.3 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.8	Form of 8.00% Debentures due April 15, 2027 (incorporated by reference to Exhibit 4.4 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.9	

Form of 7.50% Note due April 15, 2031 (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on April 9, 2001)

4.10 Officers' Certificate establishing the terms of the 6.50% Notes due 2003, 6.75% Notes due 2005, 6.95% Notes due 2008, 7.375% Notes due 2018, 9.125% Notes due 2003 and 9.50% Notes due 2008 (incorporated by reference to Exhibit 4.13 to Transocean Sedco Forex Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the fiscal year ended December 31, 2001)

4.11 Officers' Certificate establishing the terms of the 7.375% Notes due 2018 (incorporated by reference to Exhibit 4.14 to Transocean Sedco Forex Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the fiscal year ended December 31, 2001)

4.12 Indenture dated as of September 1, 1997, between Global Marine Inc. and Wilmington Trust Company, as Trustee, relating to Debt Securities of Global Marine Inc. (incorporated by reference to Exhibit 4.1 of Global Marine Inc.'s Registration Statement on Form S-4 (No. 333-39033) filed with the Commission on October 30, 1997); First Supplemental Indenture dated as of June 23, 2000 (incorporated by reference to Exhibit 4.2 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended June 30, 2000); Second Supplemental Indenture dated as of November 20, 2001 (incorporated by reference to Exhibit 4.2 to GlobalSantaFe Corporation's Annual Report on Form 10-K (Commission File No. 001-14634) for the year ended December 31, 2004)

4.13 Form of 7% Note Due 2028 (incorporated by reference to Exhibit 4.2 of Global Marine Inc.'s Current Report on Form 8-K (Commission File No. 1-5471) filed on May 22, 1998)

4.14 Terms of 7% Note Due 2028 (incorporated by reference to Exhibit 4.1 of Global Marine Inc.'s Current Report on Form 8-K (Commission File No. 1-5471) filed on May 22, 1998)

4.15 Senior Indenture, dated as of December 11, 2007, between Transocean Inc. and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.36 to Transocean Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the year ended December 31, 2007)

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

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

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

4.19 Fifth Supplemental Indenture, dated as of December 5, 2011, among Transocean Ltd., Transocean Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 5, 2011)

4.20 Sixth Supplemental Indenture, dated as of September 13, 2012, among Transocean Inc., Transocean Ltd. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on September 13, 2012)

4.21 Credit Agreement dated November 1, 2011 among Transocean Inc., the lenders parties thereto and JPMorgan Chase Bank, N.A., as administrative agent, Crédit Agricole Corporate and Investment Bank and Citibank, N.A., as co-syndication agents, and The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Wells Fargo Bank, National Association, as co-documentation agents, and J.P. Morgan Securities LLC, Crédit Agricole Corporate and Investment Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Citigroup Global Markets Inc., and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners (incorporated by reference to Exhibit 4.1 to Transocean Ltd.'s Quarterly Report on Form 10-Q (Commission File No. 000-53533) for the quarter ended September 30, 2011)

4.22 Guarantee Agreement dated November 1, 2011 among Transocean Ltd. and JPMorgan Chase Bank, N.A., as administrative agent under the Credit Agreement (incorporated by reference to Exhibit 4.2 to Transocean Ltd.'s Quarterly Report on Form 10-Q (Commission File No. 000-53533) for the quarter ended September 30, 2011)

4.23 First Amendment to Credit Agreement dated effective as of March 23, 2012 among Transocean Inc., the lenders parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, Crédit Agricole Corporate and Investment Bank and Citibank, N.A., as co-syndication agents, and The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Wells Fargo Bank, National Association, as co-documentation agents (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on March 30, 2012)

4.24 Credit Agreement, dated October 25, 2012, among Triton Nautilus Asset Leasing GmbH, the lender parties thereto and DNB Bank, ASA, as administrative agent (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on October 31, 2012)

†4.25 First Amendment to Credit Agreement, dated December 16, 2013, among Trident Nautilus Asset Leasing GmbH, the lender parties thereto and DNB Bank, ASA, as administrative agent

10.1 Tax Sharing Agreement between Sonat Inc. and Sonat Offshore Drilling Inc. dated June 3, 1993 (incorporated by reference to Exhibit 10-(3) to Sonat Offshore Drilling Inc.'s Form 10-Q (Commission File No. 001-07746) for the quarter ended June 30, 1993)

10.2 Nomination and Standstill Agreement dated as of November 10, 2013 by and between Transocean Ltd., High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Partners Master Fund II LP, Icahn Partners Master Fund III LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital LP, Icahn Onshore LP, Icahn Offshore LP, Beckton Corp., Samuel Merksamer and Vincent Intrieri (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on November 12, 2013)

*10.3 Long-Term Incentive Plan of Transocean Ltd. (as amended and restated as of February 12, 2009) (incorporated by reference to Exhibit 10.5 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.4 First Amendment to Long-Term Incentive Plan of Transocean Ltd. (as amended and restated as of February 12, 2009) (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on May 22, 2013)

*10.5 Deferred Compensation Plan of Transocean Offshore Inc., as amended and restated effective January 1, 2000 (incorporated by reference to Exhibit 10.10 to Transocean Sedco Forex Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the year ended December 31, 1999)

*10.6 GlobalSantaFe Corporation Key Employee Deferred Compensation Plan effective January 1, 2001; and Amendment to GlobalSantaFe Corporation Key Employee Deferred Compensation Plan effective November 20, 2001 (incorporated by reference to Exhibit 10.33 to the GlobalSantaFe Corporation Annual Report on Form 10-K for the year ended December 31, 2004)

*10.7 Amendment to Transocean Inc. Deferred Compensation Plan (incorporate by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 29, 2005)

*10.8 Sedco Forex Employees Option Plan of Transocean Sedco Forex Inc. effective December 31, 1999 (incorporated by reference to Exhibit 4.5 to Transocean Sedco Forex Inc.'s Registration Statement on Form S-8 (Registration No. 333-94569) filed January 12, 2000)

*10.9 1997 Long-Term Incentive Plan of Reading & Bates Corporation (incorporated by reference to Exhibit 99.A to Reading & Bates' Proxy Statement (Commission File No. 001-05587) dated March 28, 1997)

*10.10 1998 Employee Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.A to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 23, 1998)

*10.11 1998 Director Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.B to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 23, 1998)

*10.12 1999 Employee Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.A to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 13, 1999)

*10.13 1999 Director Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.B to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 13, 1999)

10.14 Master Separation Agreement dated February 4, 2004 by and among Transocean Inc., Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on March 3, 2004)

10.15 Tax Sharing Agreement dated February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.3 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on March 3, 2004)

10.16 Amended and Restated Tax Sharing Agreement effective as of February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 4.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on November 30, 2006)

*10.17 Form of 2004 Performance-Based Nonqualified Share Option Award Letter (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on February 15, 2005)

*10.18 Form of 2004 Director Deferred Unit Award (incorporated by reference to Exhibit 10.5 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on February 15, 2005)

*10.19 Form of 2008 Director Deferred Unit Award (incorporated by reference to Exhibit 10.20 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended

December 31, 2008)

*10.20 Form of 2009 Director Deferred Unit Award (incorporated by reference to Exhibit 10.19 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2009)

*10.21 Performance Award and Cash Bonus Plan of Transocean Ltd. (incorporated by reference to Exhibit 10.21 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.22 Amendment to Performance Award and Cash Bonus Plan of Transocean Ltd. (incorporated by reference to Exhibit 10.20 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2012)

*10.23 Executive Change of Control Severance Benefit (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on July 19, 2005)

*10.24 Terms of July 2007 Employee Restricted Stock Awards (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2007)

*10.25 Terms of July 2007 Employee Deferred Unit Awards (incorporated by reference to Exhibit 10.3 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2007)

*10.26 Terms and Conditions of the July 2008 Employee Contingent Deferred Unit Award (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2008)

*10.27 Terms and Conditions of the July 2008 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2008)

*10.28 Terms and Conditions of the February 2009 Employee Deferred Unit Award (incorporated by reference to Exhibit 10.28 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.29 Terms and Conditions of the February 2009 Employee Contingent Deferred Unit Award (incorporated by reference to Exhibit 10.29 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.30 Terms and Conditions of the February 2009 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.30 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.31 Terms and Conditions of the February 2012 Long Term Incentive Plan Award (incorporated by reference to Exhibit 10.28 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2011)

*10.32 Transocean Ltd. Incentive Recoupment Policy (incorporated by reference to Exhibit 10.30 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2012)

10.33 Form of Novation Agreement dated as of November 27, 2007 by and among GlobalSantaFe Corporation, Transocean Offshore Deepwater Drilling Inc. and certain executives (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)

*10.34 Form of Severance Agreement with GlobalSantaFe Corporation Executive Officers (incorporated by reference to Exhibit 10.1 to GlobalSantaFe Corporation's Current Report on Form 8-K/A (Commission File No. 001-14634) filed on July 26, 2005)

*10.35 Global Marine Inc. 1990 Non-Employee Director Stock Option Plan (incorporated by reference to Exhibit 10.18 of Global Marine Inc.'s Annual Report on Form 10-K (Commission File No. 1-5471) for the year ended December 31, 1991); First Amendment (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended June 30, 1995); Second Amendment (incorporated by reference to Exhibit 10.37 of Global Marine Inc.'s Annual Report on Form 10-K (Commission File No. 1-5471) for the year ended December 31, 1996)

*10.36 1997 Long-Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Registration Statement on Form S-8 (No. 333-7070) filed June 13, 1997); Amendment to 1997 Long Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20-F (Commission File No. 001-14634) for the calendar year ended December 31, 1998); Amendment to 1997 Long Term Incentive Plan dated December 1, 1999 (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20-F (Commission File No. 001-14634) for the calendar year ended December 31, 1999)

*10.37 GlobalSantaFe Corporation 1998 Stock Option and Incentive Plan (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended March 31, 1998); First Amendment (incorporated by reference to Exhibit 10.2 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended June 30, 2000)

*10.38 GlobalSantaFe Corporation 2001 Non-Employee Director Stock Option and Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Registration Statement on Form S-8 (No. 333-73878) filed November 21, 2001)

*10.39 GlobalSantaFe Corporation 2001 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to GlobalSantaFe Corporation's Quarterly Report on Form 10-Q (Commission File No. 001-14634) for the quarter ended June 30, 2001)

*10.40 GlobalSantaFe 2003 Long-Term Incentive Plan (as Amended and Restated Effective June 7, 2005) (incorporated by reference to Exhibit 10.4 to GlobalSantaFe Corporation's Quarterly Report on Form 10-Q (Commission File No. 001-14634) for the quarter ended June 30, 2005)

*10.41 Transocean Ltd. Pension Equalization Plan, as amended and restated, effective January 1, 2009 (incorporated by reference to Exhibit 10.41 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

*10.42 Transocean U.S. Supplemental Retirement Benefit Plan, as amended and restated, effective as of November 27, 2007 (incorporated by reference to Exhibit 10.11 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)

*10.43 GlobalSantaFe Corporation Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.1 to the GlobalSantaFe Corporation Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)

*10.44 Transocean U.S. Supplemental Savings Plan (incorporated by reference to Exhibit 10.44 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

10.45 Form of Indemnification Agreement entered into between Transocean Ltd. and each of its Directors and Executive Officers (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on October 10, 2008)

*10.46 Form of Assignment Memorandum for Executive Officers (incorporated by reference to Exhibit 10.5 to Transocean Ltd.'s Current Report on Form 8-K filed on December 19, 2008)

10.47 Drilling Contract between Vastar Resources, Inc. and R&B Falcon Drilling Co. dated December 9, 1998 with respect to Deepwater Horizon, as amended (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Quarterly Report on Form 10-Q (Commission File No. 000-53533) for the quarterly period ended June 30, 2010)

*10.48 Executive Severance Benefit Policy (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on February 23, 2012)

*10.49 Agreement with Gregory L. Cauthen (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on January 10, 2012)

*10.50 First Amendment to Agreement with Gregory L. Cauthen (incorporated by reference from Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on July 2, 2012)

*10.51 Agreement with Gregory L. Cauthen effective as of April 25, 2013 (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on April 26, 2013)

*10.52 Agreement with Allen M. Katz (incorporated by reference to Exhibit 10.55 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2012)

*10.53 First Amendment to Employment Agreement with Allen M. Katz effective as of July 1, 2013 (incorporated by reference to Exhibit 10.3 to Transocean Ltd.'s Quarterly Report on Form 10-Q (Commission File No. 000-53533) for the quarterly period ended June 30, 2013)

† *10.54 Second Amendment to Employment Agreement with Allen M. Katz effective as of January 1, 2014 and incorporated herein by reference

*10.55 Agreement with Steven L. Newman (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 23, 2013)

*10.56 Agreement with John Stobart (incorporated by reference to Exhibit 10.2 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 23, 2013)

*10.57 Agreement with Esa Ikäheimonen (incorporated by reference to Exhibit 10.3 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 23, 2013)

*10.58 Agreement with Ihab M. Toma (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 26, 2013)

† 21 Subsidiaries of Transocean Ltd.

† 23.1 Consent of Ernst & Young LLP

† 24 Powers of Attorney

† 31.1 CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

† 31.2 CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

† 32.1 CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

† 32.2 CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

99.2 Cooperation Guilty Plea Agreement by and among Transocean Deepwater Inc., Transocean Ltd. and the United States (incorporated by reference to Exhibit 99.2 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on January 3, 2013)

99.3 Consent Decree by and among Triton Asset Leasing GmbH, Transocean Holdings LLC, Transocean Offshore Deepwater Drilling Inc., Transocean Deepwater Inc. and the United States (incorporated by reference to Exhibit 99.2 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on January 3, 2013)

99.4 Administrative Agreement by and among Transocean Deepwater Inc., Transocean Offshore Deepwater Drilling Inc., Triton Asset Leasing GmbH, Transocean Holdings, LLC and the United States Environmental Protection Agency dated effective as of February 25, 2013 and incorporated herein by reference

†101.ins XBRL Instance Document

†101.sch XBRL Taxonomy Extension Schema

†101.cal XBRL Taxonomy Extension Calculation Linkbase

†101.def XBRL Taxonomy Extension Definition Linkbase

†101.lab XBRL Taxonomy Extension Label Linkbase

†101.pre XBRL Taxonomy Extension Presentation Linkbase

† Filed herewith.
* Compensatory plan or arrangement.

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 26, 2014.

TRANSOCEAN LTD.
By: /s/ Esa Ikäheimonen_____________________________
Esa Ikäheimonen
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

By: /s/ David Tonnel________________________________
David Tonnel
Senior Vice President, Finance and Controller
(Principal Accounting Officer)

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – continued

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on February 26, 2014.

Signature	Title
* Ian C. Strachan	Chairman of the Board of Directors
/s/ Steven L. Newman Steven L. Newman	President and Chief Executive Officer (Principal Executive Officer)
/s/ Esa Ikäheimonen Esa Ikäheimonen	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ David Tonnel David Tonnel	Senior Vice President, Finance and Controller (Principal Accounting Officer)
* Glyn Barker	Director
* Jagjeet S. Bindra	Director
* Thomas W. Cason	Director
* Vanessa C.L. Chang	Director
* Chad Deaton	Director

* Tan Ek Kia	Director
* Steve Lucas	Director
* Samuel Merksamer	Director
* Martin B. McNamara	Director
* Edward R. Muller	Director
* Robert M. Sprague	Director
By: /s/ David Tonnel (Attorney-in-Fact)	