Transocean Ltd.
Form 10-K
March 01, 2013

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, 2012

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 share	New York Stock Exchange SIX Swiss Exchange

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

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Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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, 2012, 359,284,907 shares were outstanding and the aggregate market value of shares held by non-affiliates was approximately $16.1 billion (based on the reported closing market price of the shares of Transocean Ltd. on June 29, 2012 of $44.73 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 20, 2013, 359,542,668 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, 2012, for its 2013 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, 2012

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,

§ the impact of the Brazil Frade field incident and related matters,

§ our results of operations and cash flow from operations, including revenues 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 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 and debt retirement,

§ 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,

§ pending or possible transactions, including the timing, benefits and terms thereof,

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

§ 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 and the United States,

§ 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

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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 contracts for our rigs that do not have contracts,

§ our inability to renew contracts at comparable dayrates,

§ operational performance,

§ the impact of regulatory changes,

§ the cancellation of contracts currently included in our reported contract backlog,

§ shipyard, construction and other delays,

§ 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 20, 2013, we owned or had partial ownership interests in and operated 82 mobile offshore drilling units associated with our continuing operations. As of this date, the fleet associated with our continuing operations consisted of 48 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters and nine High-Specification Jackups. At February 20, 2013, we also had six Ultra-Deepwater drillships and three High-Specification Jackups under construction or under contract to be constructed.

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. 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 also provide oil and gas drilling management services on either a dayrate basis or a completed-project, fixed price or turnkey basis, as well as drilling engineering and drilling project management services.

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 25—Operating Segments, Geographical Analysis and Major Customers."

Recent Developments

In November 2012, in connection with our efforts to improve the overall technical capabilities of our fleet and dispose of non-strategic assets, 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. As of February 20, 2013, we operated 25 Standard Jackups under operating agreements with Shelf Drilling. In addition, 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. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 9—Discontinued Operations."

In March 2012, we announced our intent to discontinue drilling management services operations in the shallow waters of the United States ("U.S.") Gulf of Mexico, 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.

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 for operations 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 three Enterprise-class, five Enhanced Enterprise-class and two other Ultra-Deepwater drillships, which are all 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. Our Enhanced Enterprise-class drillships offer improved reliability, increased pipe handling capacity, dual well control systems and flexible fluid capabilities and increased water depth and drilling depth.

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 three Express-class 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. Our three Development Driller-class semisubmersibles and two other 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.

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 greater operational capabilities than Standard Jackups and have higher capacity derricks, drawworks, mud systems and storage. Typically, High-Specification Jackups also have deeper water depth capacity than Standard Jackups.

As of February 14, 2013, we owned and operated a fleet of 82 rigs, excluding rigs under construction, was as follows:

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

§ 27 Ultra-Deepwater Floaters;

§ 14 Deepwater Floaters; and

§ Seven Harsh Environment Floaters;

§ 25 Midwater Floaters; and

§ Nine High-Specification Jackups.

As of February 14, 2013, we also operated a fleet of 25 previously owned Standard Jackups, associated with our discontinued operations, under operating agreements with Shelf Drilling, the buyer of these rigs. We agreed to continue to operate these rigs, for periods ranging from nine months to 27 months, until expiration or novation of the underlying drilling contracts by Shelf Drilling. See “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 9—Discontinued Operations.”

Fleet status—Depending on market conditions, we may idle or stack non-contracted rigs. An idle rig is between contracts, readily available for operations, and operating costs are typically at or near normal levels. A stacked rig is staffed by a reduced crew or has no crew and typically has reduced operating costs 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.

Drilling units—The following tables, presented as of February 14, 2013, 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 14, 2013, 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 (9)

Name	Type	Expected completion	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Ultra-Deepwater Floaters					
Deepwater Asgard	HSD	2Q 2014	12,000	40,000	To be determined
Deepwater Invictus	HSD	2Q 2014	12,000	40,000	U.S. Gulf
DSME 12000 Drillship TBN1	HSD	4Q 2015	12,000	40,000	To be determined
DSME 12000 Drillship TBN2	HSD	2Q 2016	12,000	40,000	To be determined
DSME 12000 Drillship TBN3	HSD	4Q 2016	12,000	40,000	To be determined
DSME 12000 Drillship TBN4	HSD	1Q 2017	12,000	40,000	To be determined
High-Specification Jackups					
Transocean Siam Driller	Jackup	1Q 2013	350	35,000	Thailand
Transocean Andaman	Jackup	2Q 2013	350	35,000	Thailand
Transocean Ao Thai	Jackup	4Q 2013	350	35,000	Thailand

"HSD" means high-specification drillship.

High-Specification Floaters (48)

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	U.S. Gulf
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) (e)	HSD	2009	12,000	35,000	India
Dhirubhai Deepwater KG2 (b) (e)	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	Brazil
Deepwater Frontier (b)	HSD	1999	10,000	30,000	Australia
Deepwater Millennium (b)	HSD	1999	10,000	30,000	Kenya
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	Brazil
Deepwater Nautilus (g)	HSS	2000	8,000	30,000	U.S. Gulf
GSF Explorer (b)	HSD	1972/1998	7,800	30,000	Idle
Discoverer Luanda (b) (c) (d) (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 (14)					
Deepwater Navigator (b)	HSD	1971/2000	7,200	25,000	Brazil
Discoverer Seven Seas (b)	HSD	1976/1997	7,000	25,000	Sri Lanka
Transocean Marianas (g)	HSS	1979/1998	7,000	30,000	Namibia
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 709 (b)	HSS	1977/1999	5,000	25,000	Stacked

Transocean Richardson (g)	HSS	1988	5,000	25,000	Stacked
Sedco 710 (b)	HSS	1983/2001	4,500	25,000	Brazil
Sovereign Explorer (g)	HSS	1984	4,500	25,000	Stacked
Transocean Rather (g)	HSS	1988	4,500	25,000	Angola
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 and pledged as collateral for the debt of the joint venture company.

Midwater Floaters (25)

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	Egypt
Transocean Legend	OS	1983	3,500	25,000	Australia
GSF Arctic I	OS	1983/1996	3,400	25,000	Idle
C. Kirk Rhein, Jr.	OS	1976/1997	3,300	25,000	Stacked
Transocean Driller	OS	1991	3,000	25,000	Brazil
GSF Rig 135	OS	1983	2,800	25,000	Nigeria
GSF Rig 140	OS	1983	2,800	25,000	India
Falcon 100	OS	1974/1999	2,400	25,000	Brazil
GSF Aleutian Key	OS	1976/2001	2,300	25,000	Stacked
Sedco 703	OS	1973/1995	2,000	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 (9)

Name	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Location
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	Denmark
GSF Monitor	1989	350	30,000	Nigeria

(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.

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 14, 2013, the fleet associated with our continuing operations was located in the U.S. Gulf of Mexico (15 units), United Kingdom ("U.K.") North Sea (12 units), Brazil (10 units), Far East (nine units), Norway (seven units), Nigeria (seven units), India (five units), West African countries other than Nigeria and Angola (five units), Angola (four units), Australia (three units), Canada (two units), Middle East (two units), and Denmark (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 semisubmersibles and drillships. 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,		
	2012	2011	2010
Operating revenues			

U.S.	$ 2,472	$ 1,971	$ 1,937
Norway	1,174	897	765
Brazil	1,114	1,019	1,288
U.K.	1,028	1,099	1,097
Other countries (a)	3,408	3,041	2,862
Total operating revenues	$ 9,196	$ 8,027	$ 7,949

(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, 2012	2011
Long-lived assets		
U.S.	$ 7,395	$ 6,553
Brazil	2,285	2,185
Norway	2,072	2,067
Other countries (a)	9,128	9,983
Total long-lived assets	$ 20,880	$ 20,788

(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 Backlog

At December 31, 2012, the contract backlog associated with our continuing operations was approximately $29.4 billion, representing a 40.7 percent and 24.6 percent increase compared to the contract backlog associated with our continuing operations at December 31, 2011 and 2010, which was $20.9 billion and $23.6 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."

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 contracts through competitive bidding against other contractors. Drilling contracts generally provide for payment on a dayrate basis, with higher rates 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. Certain of our 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 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 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 (e.g., 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 amount is usually $5 million or less, although the amount can be greater depending on the nature of our liability. 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.”

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 certain penalties and punitive damages under the Clean Water Act (“CWA”) 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 and cash flows. Courts also restrict indemnification for criminal fines and penalties. See “Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 17—Commitments and Contingencies—Macondo we incident—Contractual indemnity.”

Drilling Management Services

We provide drilling management services primarily on a turnkey basis through Applied Drilling Technology Inc., a Texas corporation and our wholly owned subsidiary, which primarily operates in non-U.S. market sectors outside of the North Sea, and through ADT International, a division of one of our U.K. subsidiaries, which primarily operates in the North Sea (together, "ADTI"). As part of our drilling management services, we provide planning, engineering and management services beyond the scope of our traditional contract drilling business and, thereby, assume greater risk. Under turnkey arrangements, we typically assume responsibility for the design and execution of a well and deliver a logged or cased hole to an agreed depth for a guaranteed price for which payment is contingent upon successful completion of the well program.

In addition to turnkey drilling management services, we participate in project management operations that include providing certain planning, management and engineering services, purchasing equipment and providing personnel and other logistical services to customers. Our project management services differ from turnkey drilling services in that the customer assumes control of the drilling operations and thereby retains the risks associated with the project.

In March 2012, we announced our intent to discontinue drilling management services operations in the shallow waters of the U.S. Gulf of Mexico, a component of our drilling management services segment, upon completion of our then existing contracts. In December 2012, we completed the final project for our drilling management services operations in the U.S. Gulf of Mexico and discontinued offering our drilling management services in the U.S.

Revenues from the continuing operations of our drilling management services represented less than three percent of our consolidated revenues from continuing operations for the year ended December 31, 2012. In the course of providing drilling management services, ADTI may either use a drilling rig in our fleet or contract for a rig owned by another contract driller.

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.

We hold a 65 percent interest in Angola Deepwater Drilling Company Limited ("ADDCL"), a consolidated Cayman Islands joint venture company formed to own Discoverer Luanda. 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 Transocean Drilling Services Offshore Inc. ("TDSOI"), a consolidated British Virgin Islands joint venture company formed to own Transocean Honor. Our local partner, Angco II, a Cayman Islands company, holds the remaining 30 percent interest in TDSOI. Under certain circumstances, Angco II will have the right to exchange its interest in the joint venture for cash at an amount based on an appraisal of the fair value of the jackup, subject to certain adjustments.

We hold a 65 percent interest in TSSA – Servicos de Apoio, Lda. ("TSSA"), a consolidated Angola limited liability company formed to operate Discoverer Luanda and Transocean Honor. Our local partner, Angco Cayman Limited, a Cayman Islands company, holds the remaining 35 percent interest in TSSA. Under a management services agreement with TSSA, we provide operating management services for Discoverer Luanda and Transocean Honor.

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, 2012, our most significant customers were Chevron Corporation, BP America Production Co. (together with its affiliates, "BP") and Petrobras, accounting for approximately 11 percent, 11 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, 2012. 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, 2012, we had approximately 18,400 employees associated with our continuing operations, including approximately 1,700 persons engaged through contract labor providers. Of our 18,400 employees, approximately 3,000 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. 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.

Technological Innovation

We are a leading international provider of offshore contract drilling services and drilling management 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, the first semisubmersible rig for year-round Sub-Arctic operations, and the latest generations of ultra-deepwater drillships and semisubmersibles. Fifteen rigs in our existing fleet, and six of our rigs that are currently under construction, are 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. In 2011, we acquired two custom designed, 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 jackup drilling rigs currently 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. In 2012, we entered into shipyard contracts for the construction of four newbuild dynamically positioned Ultra-Deepwater drillships that will be equipped with dual activity, industry-leading hoisting capacity, a second blowout preventer system and will be outfitted to accommodate a future upgrade to a 20,000 psi blowout preventer. We continue to seek to develop industry-leading technology, including managed pressure drilling solutions, emission monitoring, hybrid power systems, and advanced generator protection. The effective use of and continued improvements in technology are critical to maintaining our competitive position within the drilling services industry. We expect to continue to develop technology internally 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 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 information related to our corporate governance, board committees and company code of business conduct and ethics on our website. 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 will not be deductible for tax purposes, and the criminal fines will not be covered in full by insurance. 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 "We could experience a material adverse effect on our consolidated statement of financial position, results of operations and 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 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.

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. In the three years ended December 31, 2012, we estimate that the Macondo well incident had a direct and indirect effect of greater than $1.0 billion in lost revenues and incremental costs and expenses associated with extended shipyard projects and increased downtime, both as a result of complying with the enhanced regulations and our customers' requirements. We also lost approximately $1.1 billion of contract backlog associated with the termination of the Deepwater Horizon contract in April 2010 resulting from the loss of the rig and the termination of another drilling contract in December 2011 resulting from the previously mentioned increased downtime. Through December 31, 2012, we have recognized estimated losses of $1.9 billion in connection with loss contingencies associated with the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. Additionally, in the three years ended December 31, 2012, we incurred cumulative incremental costs, primarily associated with legal expenses for lawsuits and investigations, in the amount of $372 million. Collectively, the lost contract backlog from the incident and from the termination in December 2011, the lost revenues and incremental costs and expenses and other losses have had an effect of greater than $4.0 billion.

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. We have recognized a liability for such loss contingencies in the amount of $1.9 billion. 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 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 and 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 that 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 other 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 11 percent of our consolidated operating revenues from continuing operations for the year ended December 31, 2012. Ultimately, these factors could have a material adverse effect on our 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 and 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. According to its public filings, the operator has recognized cumulative pre-tax losses of $42.2 billion in relation to the spill as of February 5, 2013. As described under "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 17—Commitments and Contingencies—Macondo well incident—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 ultimately experience a material adverse effect on our consolidated statement of financial position, results of operations and 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 breached the drilling contract or 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 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 ("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. As part of this resolution, we agreed to pay $1.4 billion in fines, recoveries and civil penalties, excluding interest, in scheduled payments over a five-year period through 2017, which will decrease our available liquidity capacity. Our settlement with the DOJ does not release us from liabilities to the U.S. government as to all Macondo-related matters nor does it release all Transocean-related persons and entities. In particular, this agreement is 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, 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. Both our criminal Plea Agreement and our civil Consent Decree have received final court approval. We will incur costs, expenses and be required to devote management and other corporate resources to comply with our agreements with the U.S. Under these agreements, we will be subject to restrictions and obligations not imposed on other drilling contractors, which may adversely impact us.

See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 17—Commitments and Contingencies—Macondo well incident—Litigation."

Pursuant to our Plea Agreement, we will be subject to five years' probation. Pursuant to the terms of our civil Consent Decree, we will be subject to the restrictions of that decree for an extended period of time that will be at least five years. 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 17—Commitments and Contingencies—Macondo well incident—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 17—Commitments and Contingencies—Macondo well incident—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.

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, and may continue to 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 with the DOJ 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.

The Frade Field incident in Brazil could result in increased expenses and decreased revenues, which could ultimately have a material impact on us.

On or about November 7, 2011, oil was released from fissures in the ocean floor in the vicinity of a development well being drilled by Chevron off the coast of Rio de Janeiro in the Campo de Frade field with our Deepwater Floater Sedco 706. In connection with the incident, authorities in Brazil have filed a civil action against Chevron and us. We may be subject to liability for civil damage and governmental fines or penalties. If we ultimately incur substantial liabilities in connection with these matters for which we are neither insured nor indemnified, those liabilities could adversely affect our consolidated statement of financial position, results of operations or cash flow. In addition, a prosecutor in the town of Campos in Rio de Janeiro State sought an injunction to prevent Chevron and us from conducting extraction or transportation activities in Brazil and to seek to require Chevron to stop the release and remediate its effects. In July 2012, the appellate court granted the requested for preliminary injunction. On September 22, 2012, the federal court in Rio de Janeiro served us with the preliminary injunction. The terms of this injunction required us to cease conducting extraction or transportation activities in Brazil within 30 days from the date of service. On September 28, 2012, the Brazilian Superior Court of Justice partially suspended this preliminary injunction. As a result of this suspension, the preliminary injunction only applied to our operations in the Campo de Frade field, and we could continue to operate in all other offshore oil and gas fields in Brazil. On November 27, 2012, the Court of Appeals in Rio de Janeiro ruled unanimously to suspend the entire preliminary injunction order, including the injunction in the Campo de Frade field that had been entered in July 2012. This ruling was published on December 5, 2012. The lawsuit will continue in the trial court, and there remains a risk that the preliminary injunction could be reinstated, or that at the conclusion of the case Brazilian authorities could permanently enjoin us from further operations in Brazil. For the year ended December 31, 2012, our operations in Brazil accounted for 12 percent of our consolidated operating revenues. If we are enjoined from operating in Brazil for a substantial period of time, the resulting decrease in demand for our drilling services could ultimately have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

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 and development 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;
- adverse weather conditions; 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.

Our 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 service and equipment are also considered.

Our 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 intensify the competition in the industry and often result in rigs being idle for long periods of time. We have idled and stacked rigs, and may in the future idle or stack additional rigs or enter into lower dayrate contracts in response to market conditions. We cannot predict when any idled or stacked rigs will return to service.

During prior periods of high dayrates and rig utilization rates, 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 jackups that have entered the 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 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.

Our overall debt level was approximately $12.5 billion and $13.5 billion at December 31, 2012 and 2011, 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 "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, 2012, our most significant customers were Chevron, BP and Petrobras, accounting for approximately 11 percent, 11 percent and 10 percent, respectively, of our consolidated operating revenues from continuing operations. As of February 14, 2013, the aggregate amount of contract backlog associated with our contracts with Chevron, BP and Petrobras was $6.8 billion. Additionally, in the year ended December 31, 2012, we entered into 10-year drilling contracts with Royal Dutch Shell plc ("Royal Dutch Shell") for four newbuild Ultra-Deepwater drillships. As of February 14, 2013, the aggregate amount of contract backlog associated with Royal Dutch Shell was $8.8 billion. 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. The loss of any of these customers or another significant customer could, at least in the short term, have a material adverse effect on our results of operations and cash flows.

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 high specification parts and equipment 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. 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 operating revenues.

Our operating and maintenance costs will not necessarily fluctuate in proportion to changes in 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 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 20, 2013, we had six Ultra-Deepwater Floater and three 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 one of these 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, 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.

Compliance with or breach of environmental laws can be costly and could limit our operations.

Our operations are subject to regulations controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment. For example, 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. 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 could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. In addition, our Consent Decree and probation arising out of our guilty plea agreement with the DOJ add to these regulations, requirements and liabilities. Numerous lawsuits, including one brought by the DOJ, allege that we may have liability under the environmental laws relating to the Macondo well incident. 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 such liabilities. 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.”

There is no assurance that we can obtain enforceable indemnities against liability for pollution, well and environmental damages in all of our contracts or that, in the event of extensive pollution and environmental damages, our customers or other third parties will have the financial capability to fulfill their indemnity obligations to us. A court in the litigation related to the Macondo well incident has refused to enforce all aspects of our indemnity with respect to certain environmental-related liabilities.

Our drilling contracts may be terminated due to a number of events.

Certain of our 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. 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.

At February 14, 2013, the contract backlog associated with our continuing operations was approximately $28.8 billion. This amount represents the firm term of the 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 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, as described under “Our drilling contracts may be terminated due to a number of events” above. 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 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. 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Regulatory matters." We have also operated rigs in Myanmar, a country that is subject to some U.S. trading sanctions. 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. For example, in the past few years, we have experienced considerable difficulty in obtaining the necessary visas and work permits for our employees to work in Angola, where we operate a number of rigs. 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 contracts, and we are unable to secure new 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.

Our operations are subject to the usual hazards inherent in the drilling of oil and gas wells, such as blowouts, reservoir damage, loss of production, loss of well control, punch-throughs, craterings, fires and natural disasters such as hurricanes and tropical storms. We may also be subject to property, environmental and other damage claims by oil and gas companies. Our insurance policies and contractual rights to indemnity may not adequately cover losses, and we do not have insurance coverage or rights to indemnity for all risks. There are also risks following the loss of control of a well, such as a blowout or cratering, including the cost to regain control of or redrill the well and associated pollution. Damage to the environment could also result from our operations, particularly through oil spillage or extensive uncontrolled fires.

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. We are also subject to personal injury and other claims by rig personnel as a result of our drilling operations. Operations also may be suspended because of machinery breakdowns, abnormal drilling conditions, failure of subcontractors to perform or supply goods or services, or personnel shortages. In addition, offshore drilling operations are subject to perils peculiar to marine operations, including capsizing, grounding, collision and loss or damage from severe weather.

We have two main types of insurance coverage: (1) hull and machinery coverage for property damage 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 coverage for hull and machinery exposure for named storms in the U.S. Gulf of Mexico. We also generally self-insure coverage for ADTI exposures related to well control and redrill liability for well blowouts. However, in the event of a total loss of such a drilling unit there is no deductible. We also maintain per occurrence deductibles on such rigs that generally range up to $10 million for various third-party liabilities and an additional aggregate annual self-insured retention of $50 million. With respect to the remaining $775 million excess liability coverage, we generally retain the risk for any liability in excess of this coverage; however, our wholly-owned captive insurance company has underwritten the $50 million self-insured retention noted above.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a customer or, with respect to the Standard Jackups we operate under operating agreements with Shelf Drilling for a transitional period, Shelf Drilling, it could adversely affect our consolidated statement of financial position, results of operations or cash flows. The amount of our insurance may 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. Moreover, no assurance can be made that we will be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

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, including for turnkey drilling and drilling management services businesses and construction projects, 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 and economic conditions could have a material adverse effect on our revenue, profitability and financial position.

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. 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 revenue, profitability and financial position.

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

The U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions, including the U.K. Bribery Act 2010, which became effective on July 1, 2011, 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 FCPA violations or violations under the Bribery Act 2010, 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. On November 4, 2010, we reached a settlement with the SEC and the DOJ with respect to certain charges relating to the anti-bribery and books and records provisions of the FCPA. In November 2010, under the terms of the settlements, we paid a total of approximately $27 million in penalties, interest and disgorgement of profits. We have also consented to the entry of a civil injunction in two SEC actions and have entered into a three-year deferred prosecution agreement with the DOJ (the "DPA"). In connection with the DPA, we have agreed to implement and maintain certain internal controls, policies and procedures. For the duration of the DPA, we are also obligated to provide an annual written report to the DOJ of our efforts and progress in maintaining and enhancing our compliance policies and procedures. In the event the DOJ determines that we have knowingly violated the terms of the DPA, the DOJ may impose an extension of the term of the agreement or, if the DOJ determines we have breached the DPA, the DOJ may pursue criminal charges or a civil or administrative action against us. The DOJ may also find, in its sole discretion, that a change in circumstances has eliminated the need for the corporate compliance reporting obligations of the DPA and may terminate the DPA prior to the three-year term. Failure to comply with the terms of the DPA may impact our operations and any resulting fines may have a material adverse effect on our results of operations or cash flows.

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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Regulatory matters."

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

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

Legislation to regulate emissions of GHGs has been introduced in the U.S. Congress, 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 U.S. Environmental Protection Agency ("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 and the Frade field 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 challenged, 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 a trial 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.

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. U.S. 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.

Our contracts do not generally provide indemnification against loss of capital assets or loss revenues resulting from acts of terrorism, piracy or social unrest. We have limited insurance coverage for physical damage losses resulting from risks, such as terrorist acts, piracy, civil unrest, expropriation and acts of war, for our assets, but we do not carry insurance for loss of revenues resulting from such risks.

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.

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, in November 2011 and again in February 2013, the U.S. Congress introduced a proposal which would disallow any deduction for otherwise tax deductible payments relating to any incident resulting in the discharge of oil into navigable waters, such as the Macondo well incident. Any material change in tax laws or policies, or their interpretation, resulting from such legislative proposals or inquiries could result in a higher effective tax rate on our worldwide earnings and such change could have a material adverse effect on our statement of financial position, results of operations and 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, there is considerable uncertainty as to the activities that constitute being engaged in a trade or business within the U.S. (or maintaining a permanent establishment under an applicable treaty), so we cannot be certain that the U.S. Internal Revenue Service ("IRS") will not contend successfully that we or any of our key subsidiaries were or are engaged in a trade or business in the U.S. (or, when applicable, maintained or maintains a permanent establishment in the U.S.). 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. This trial is currently ongoing. We cannot be certain that the Norwegian authorities will not be successful in proving their allegations in a Norwegian court of law. 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," or 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 (which 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 goodwill and long-lived assets that are subject to impairment testing.

At December 31, 2012, the carrying amount of our property and equipment was $20.9 billion, representing 61 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 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 aggregate losses of $5.3 billion on the impairment of goodwill associated with our contract drilling services reporting unit due to a decline in projected cash flows and market valuations for this reporting unit. Future expectations of low dayrates or rig utilization rates could result in the recognition of additional losses on impairment of our long-lived asset groups, particularly with respect to our High-Specification Jackups, 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 have agreed to indemnify Shelf from certain liabilities, and Shelf Drilling has 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 have agreed to indemnify Shelf Drilling from certain liabilities, and Shelf Drilling has 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 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. 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, results of operations and financial condition.

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.

Swiss law allows our shareholders to authorize share capital that can be issued by the board of directors without additional shareholder approval, but this authorization is limited to 50 percent of the existing registered share capital and must be renewed by the shareholders every two years. At the annual general meeting on May 13, 2011, our shareholders approved our current authorized share capital, which expires on May 13, 2013 and was limited to 19.99 percent of our existing share capital. In connection with our December 2011 and May 2012 issuance of new shares, our available authorized share capital decreased to 7.61 percent of our existing stated share capital. Additionally, subject to specified exceptions, Swiss law grants preemptive rights to existing shareholders to subscribe for new issuances of shares. Swiss law also 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. In the event we need to raise common equity capital at a time when the trading price of our shares is below the par value of the shares, currently CHF 15, equivalent to $16.13 based on a foreign exchange rate of CHF 0.93 to USD 1.00 on February 20, 2013, we will need to obtain approval of shareholders to decrease the par value of our shares or issue another class of shares with a lower par value. Any reduction in par value would decrease our par value available for future repayment of share capital not subject to Swiss withholding tax. Swiss law also reserves for approval by shareholders 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. Dividend distributions out of qualifying additional paid-in capital do not require registration with the Commercial Register of the Canton of Zug. However, the Swiss withholding tax rules could also be changed in the future. Due to the continuing debate in the Swiss political arena, we cannot provide assurance that the current Swiss law with respect to distributions out of additional paid-in capital will not be changed or that a change in Swiss law will not adversely affect us or our shareholders, in particular as a result of distributions out of additional paid-in capital becoming subject to Swiss federal withholding tax or subject to additional corporate law restrictions. 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 (the "Share Repurchase Program"). On February 12, 2010, our board of directors authorized our management to implement the Share Repurchase Program. 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:

§ classify our board into three classes of directors, each of which serve for staggered three-year periods;

§ provide that the board of directors is authorized, subject to obtaining shareholder approval every two years, at any time during a maximum two-year period, which is currently scheduled to expire on May 13, 2013, to issue up to a specified number of shares, currently approximately 7.61 percent of the share capital registered in the commercial register, and to limit or withdraw the preemptive rights of existing shareholders in various circumstances, including (1) following a shareholder or group of shareholders acting in concert having acquired in excess of 15 percent of the share capital registered in the commercial register without having submitted a takeover proposal to shareholders that is recommended by the board of directors or (2) for purposes of the defense of an actual, threatened or potential unsolicited takeover bid, in relation to which the board of directors has, upon consultation with an independent financial adviser retained by the board of directors, not recommended acceptance to the shareholders;

§ 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.

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; Barbados and Luxembourg.

Our remaining offices and bases are located in various countries in North America, South America, the Caribbean, 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 17—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, 2012. We are also involved in various tax matters as described in "Part II. Financial Statements and Supplementary Data—Notes to Condensed Consolidated Financial Statements—Note 8—Income Taxes" and in "Part II. Item 7. Managemen Discussion 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, 2012. All such actions, claims, tax and other matters are incorporated herein by reference.

As of December 31, 2012, 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 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 20, 2013, on our executive officers in Part I of this report in reliance on General Instruction (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 the executive officers named below.

Officer	Office	Age as of February 20, 2013
Steven L. Newman	President and Chief Executive Officer	48
Esa Ikäheimonen	Executive Vice President, Chief Financial Officer	49
Allen M. Katz	Interim Senior Vice President and General Counsel	64
John B. Stobart		58

	Executive Vice President, Chief Operating Officer	
Ihab Toma	Executive Vice President, Chief of Staff	49
David Tonnel	Senior Vice President, Finance and Controller	43

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.

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. 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.

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.

Ihab Toma is Executive Vice President, Chief of Staff of the Company. Before being named to his current position in October 2012, Mr. Toma served as Executive Vice President, Operations from August 2011 to October 2012. Mr. Toma also served as Executive Vice President, Global Business from August 2010 to August 2011 and as Senior Vice President, Marketing and Planning from August 2009 to August 2010. Before joining the Company, Mr. Toma served as Vice President, Sales and Marketing for Europe, Africa and Caspian for Schlumberger Limited from April 2006 to August 2009. Prior to April 2006, Mr. Toma led Schlumberger Information Solutions in various capacities, including Vice President, Sales and Marketing, President of Schlumberger Information Solutions, Vice President of Information Management and Vice President of Europe, Africa and CIS Operations. He started his career with Schlumberger Limited in 1986. Mr. Toma received his Bachelor of Science in Electrical Engineering from Cairo University in 1985.

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

Market and share prices—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			
	2012		2011		2012		2011	
	High	Low	High	Low	High	Low	High	Low
First quarter	$ 59.03	$ 38.80	$ 85.98	$ 68.89	CHF 54.30	CHF 36.70	CHF 79.95	CHF 64.60
Second quarter	56.36	39.32	83.05	59.30	50.80	37.92	75.80	49.58
Third quarter	50.38	43.04	65.39	47.70	49.06	41.55	55.25	36.52
Fourth quarter	49.50	43.65	60.09	38.21	46.62	40.18	51.70	36.02

On February 20, 2013, the last reported sales price of our shares on the NYSE and the SIX was $54.32 per share and CHF 51.15 per share, respectively. On such date, there were 7,465 holders of record of our shares and 359,542,668 shares outstanding.

Shareholder matters—In May 2011, at our annual general meeting, our shareholders approved the distribution of additional paid-in capital in the form of a United States ("U.S.") dollar denominated dividend of $3.16 per outstanding share, payable in four equal installments of $0.79 per outstanding share, subject to certain limitations. On June 15, 2011, September 21, 2011 and December 21, 2011 we paid the first three installments, in the aggregate amount of $763 million, to shareholders of record as of May 20, 2011, August 26, 2011 and November 25, 2011, respectively. On March 21, 2012, we paid the final installment in the aggregate amount of $278 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 and (4) 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 Shareholders of Transocean

The tax consequences discussed below are not a complete analysis or listing of all the possible tax consequences that may be relevant to shareholders of Transocean. 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—Distributions to Shareholders" and "—Exemption fro Swiss Withholding Tax—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—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 from Swiss Withholding Tax—Distributions to Shareholders" 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. See "—Refund of Swiss Withholding Tax on Dividends and Other Distributions."

Exemption from Swiss Withholding Tax—Distributions to Shareholders

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, 2012, the aggregate amount of par value of our outstanding shares was CHF 5.6 billion, equivalent to $6.1 billion, and the aggregate amount of qualifying additional paid-in capital of our outstanding shares was at least CHF 11.2 billion, equivalent to at least $12.2 billion, at an exchange rate of $1.00 to CHF 0.92 on December 31, 2012. Consequently, we expect that a substantial amount of any potential future distributions may be exempt from Swiss withholding tax.

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.

With respect to the refund of Swiss withholding tax from the repurchase of shares, see "—Refund of Swiss Withholding Tax on Dividends and Other Distributions" below.

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.

Refund of Swiss Withholding Tax on Dividends and Other Distributions

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.

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.

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.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased

			of Publicly Announced Plans or Programs (2)	Under the Plans or Programs (2) (in millions)
October 2012	11,160	$ 47.51	—	$ 3,560
November 2012	12,626	44.85	—	3,560
December 2012	3,403	46.26	—	3,560
Total	27,189	$ 46.12	—	$ 3,560

(1) Total number of shares purchased in the fourth quarter of 2012 includes 27,189 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 $3.8 billion at an exchange rate as of the close of trading on December 31, 2012 of USD 1.00 to CHF 0.92). On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. We may decide, based upon our ongoing capital requirements, the price of our shares, matters relating to the Macondo well incident, regulatory and tax considerations, cash flow generation, the relationship between our contract backlog and our debt, general market conditions and other factors, that we should retain cash, reduce debt, make capital investments or otherwise use cash for general corporate purposes, and consequently, repurchase fewer or no 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, 2012, we have repurchased a total of 2.9 million of our shares under this share repurchase program at a total cost of $240 million ($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, 2012 and 2011 and for each of the three years in the period ended December 31, 2012 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, 2010, 2009 and 2008, and for each of the two years in the period ended December 31, 2009 have been derived from our accounting records. We have reclassified the financial data of our discontinued operations for all periods presented. See "Item 8. Financial Statements and Supplementary Data—Notes and Consolidated Financial Statements—Note 9—Discontinued Operations." 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,				
	2012	2011 (a)	2010	2009	2008
	(In millions, except per share data)				
Statement of operations data					
Operating revenues	$ 9,196	$ 8,027	$ 7,949	$ 8,910	$ 8,917
Operating income (loss)	1,581	(4,762)	2,730	3,525	3,901
Income (loss) from continuing operations	816	(5,762)	1,863	2,426	2,736
Net income (loss)	(211)	(5,677)	969	3,170	4,029
Net income (loss) attributable to controlling interest	(219)	(5,754)	926	3,181	4,031
Per share earnings (loss) from continuing operations					
Basic	$ 2.27	$ (18.14)	$ 5.66	$ 7.56	$ 8.58
Diluted	$ 2.27	$ (18.14)	$ 5.66	$ 7.54	$ 8.52
Balance sheet data (at end of period)					
Total assets	$ 34,255	$ 35,032	$ 36,814	$ 36,436	$ 35,182
Debt due within one year	1,367	2,187	2,160	1,868	664
Long-term debt	11,092	11,349	9,061	9,849	12,893
Total equity	15,730	15,627	21,340	20,559	17,167
Other financial data					
Cash provided by operating activities	$ 2,708	$ 1,825	$ 3,906	$ 5,598	$ 4,959
Cash used in investing activities	(389)	(1,896)	(721)	(2,694)	(2,196)
Cash provided by (used in) financing activities	(1,202)	734	(961)	(2,737)	(3,041)

Capital expenditures	1,303	974	1,349	2,948	2,037
Distributions of qualifying additional paid-in capital	278	763	—	—	—
Per share distributions of qualifying additional paid-in capital	$ 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 20, 2013, we owned or had partial ownership interests in and operated 82 mobile offshore drilling units associated with our continuing operations. As of February 20, 2013, our fleet consisted of 48 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters, and nine High-Specification Jackups. At February 20, 2013, we also had six Ultra-Deepwater drillships and three High-Specification Jackups under construction or under contract to be constructed.

We have two operating segments: (1) contract drilling services and (2) drilling management services. Contract drilling services, our primary business, 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 jackups used in support of offshore drilling activities and offshore support services on a worldwide basis.

Our contract drilling 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 improve the overall technical capabilities of our fleet and dispose of non-strategic assets, 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. As of February 20, 2013, we operated 25 Standard Jackups under operating agreements with 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. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 9—Discontinued Operations."

Our drilling management services segment provides oil and gas drilling management services on either a dayrate basis or a completed-project, fixed-price or turnkey basis, as well as drilling engineering and drilling project management services. We provide drilling management services outside of the U.S. through Applied Drilling Technology Inc., our wholly owned subsidiary, and through ADT International, a division of one of our United Kingdom ("U.K.") subsidiaries (together, "ADTI").

Significant Events

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."

Fleet expansion—In May 2012, we completed construction of the High-Specification Jackup Transocean Honor, and the drilling unit commenced operations under its contract. See "—Liquidity and Capital Resources—Drilling Fleet."

In September 2012, we were awarded 10-year drilling contracts for four newbuild dynamically positioned Ultra-Deepwater drillships. We also entered into shipyard contracts for the construction of such drillships. See "—Performance and Other Key Indicators—Contract Backlog" and "—Liquidity and Capital Resources—Drilling Fleet."

Discontinued operations—In November 2012, in connection with our efforts to dispose of non-strategic assets, we completed the sale of 37 Standard Jackups and one swamp barge to Shelf Drilling. As of February 20, 2013, we operated 25 Standard Jackups under operating agreements with Shelf Drilling. See "—Operating Results—Discontinued Operations."

In December 2012, having completed the final drilling management project in the shallow waters of the U.S. Gulf of Mexico, we discontinued the U.S. operations of our drilling management services segment. See—"Results of Operations—Discontinued Operations."

During the year ended December 31, 2012, we completed the sale of the assets of Challenger Minerals Inc. and Challenger Minerals (Ghana) Limited. See "—Results of Operations—Discontinued Operations."

Dispositions—During the year ended December 31, 2012, we completed the sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham and related equipment. In connection with the sales, we received aggregate net cash proceeds of $178 million. See "—Liquidity and Capital Resources—Drilling Fleet."

Debt issuance—In September 2012, we issued $750 million aggregate principal amount of 2.5% Senior Notes due October 2017 and $750 million aggregate principal amount of 3.8% Senior Notes due October 2022. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Three-Year Secured Revolving Credit Facility—On October 25, 2012, we entered into a bank credit agreement, which establishes a $900 million senior secured revolving credit facility expiring on October 25, 2015. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Debt repurchase—Holders of the 1.50% Series C Convertible Senior Notes due 2037 ("Series C Convertible Senior Notes") had the option to require Transocean Inc., our wholly owned subsidiary and the issuer of the Series C Convertible Senior Notes, to repurchase all or any part of such holder's notes on December 17, 2012. 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. 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. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Transocean Pacific Drilling Inc.—On February 29, 2012, Quantum Pacific Management Limited ("Quantum") exercised its right, pursuant to a put option agreement, to exchange its interest in Transocean Pacific Drilling Inc. ("TPDI") for our shares or cash, and, on March 29, 2012, Quantum elected to exchange its interest in TPDI for our shares, net of Quantum's share of TPDI's indebtedness. On May 31, 2012, we issued 8.7 million shares to Quantum in a non-cash exchange for its interest in TPDI. In August 2012, we paid $72 million as the final cash settlement, representing 50 percent of TPDI's working capital at May 29, 2012. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Distribution of qualifying additional paid-in capital—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 equal installments of $0.79 per outstanding share, subject to certain limitations. On March 21, 2012, we paid the final installment in the aggregate amount of $278 million to shareholders of record as of February 24, 2012.

Outlook

Drilling market—We expect the commodity pricing underlying the exploration and production programs of our customers to continue to support contracting opportunities for all asset classes within our drilling fleet in the year ending December 31, 2013. As of February 14, 2013, the contract backlog for our continuing operations was $28.8 billion compared to $29.7 billion as of October 17, 2012.

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. Although the enhanced regulations have affected our revenues, costs and out of service time, we are unable to predict, with certainty, the magnitude with which the enhanced regulations will continue to impact our operations.

Fleet status—As of February 14, 2013, uncommitted fleet rates for the remainder of 2013, 2014, 2015 and 2016 were as follows:

	2013	2014	2015	2016
Uncommitted fleet rate (a)				
High-Specification Floaters	14%	45%	67%	79%
Midwater Floaters	44%	50%	75%	98%
High-Specification Jackups	9%	31%	49%	75%

(a) The uncommitted fleet rate is defined as the number of uncommitted days divided by the total number of available 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 14, 2013, we had six 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 2013. 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—Our Ultra-Deepwater Floater fleet has six units with availability in 2013, and in the second quarter of 2014, the Ultra-Deepwater drillship Deepwater Asgard, is expected to be available to commence operations. During the fourth quarter of 2012, 12 contracts for Ultra-Deepwater Floaters were entered into worldwide, including two long-term contracts for our High-Specification Floater fleet. We expect continued customer demand to support high rig utilization rates for the Ultra-Deepwater Fleet and provide opportunities to absorb the near-term supply through 2013. The Deepwater Floater fleet rig utilization rate for the industry dropped slightly during the fourth quarter of 2012 with some available units in the global fleet coming off contract without immediate follow on work. However, the tendering activity and contract term remain stable over the previous quarter, and we are in active discussions with our customers on a few of the units available in 2013. As of February 14, 2013, we had 34 of our 48 High-Specification Floaters contracted through the end of 2013. 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 may see a flattening of dayrates and more competition for term opportunities in the short term.

Midwater Floaters—Customer demand for our Midwater Floater fleet, which includes 25 semisubmersible rigs, has continued to increase in the U.K. and Norway with multiple customers interested in available rigs. We entered into two contracts for our Midwater Floater fleet in the fourth quarter of 2012, one of which was at a leading edge dayrate for this asset class offshore UK. Based on the customer demand, we continue to believe that we could have new opportunities to extend the contracts on our active fleet available in 2013 and 2014 and reactivate one Midwater Floater in the U.K. The tendering pace and expected demand outside of the U.K. and Norway has slowed, notably in Brazil, which could have an impact on global utilization and dayrates for this asset class in 2013.

High-Specification Jackups—Our High-Specification Jackup fleet continues to benefit from the interest of our customers, evidenced by four drilling contracts signed in the fourth quarter 2012. We believe that the currently high rig utilization rates will continue to prevail during this period and increased tendering and contracting activity to continue through 2013 and into 2014. As of February 14, 2013, three of our existing nine High-Specification Jackups have availability in 2013.

Operating results—We expect our total revenues for the year ending December 31, 2013 to be higher than our total revenues for the year ended December 31, 2012, primarily due to increased dayrates, fewer expected out of service and idle days, increased activity for our drilling management services segment and increased drilling activity associated with the commencement of operations of our newbuild unit delivered in 2012 and those newbuild units to be delivered in 2013. We are unable to predict, with certainty, the full impact that the enhanced regulations, described under "—Drilling market", will have on our operations for the year ending December 31, 2013 and beyond.

After adjusting for loss contingencies recognized in the year ended December 31, 2012, we expect our total operating and maintenance expenses for the year ending December 31, 2013 to be higher than our total operating and maintenance expenses for the year ended December 31, 2012, primarily due to higher costs and expenses associated with normal inflationary trends for personnel, maintenance and other operating costs, increased activity for our drilling management services segment, and increased drilling activity associated with the commencement of operations of our newbuild units to be delivered in 2013 and increased shipyard costs. Our projected operating and maintenance expenses for the year ending December 31, 2013 are subject to change and could be affected by actual activity levels, rig reactivations, the enhanced regulations 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 and cash flows. In the three years ended December 31, 2012, we estimate that the Macondo well incident had a direct and indirect effect of greater than $1.0 billion in lost revenues and incremental costs and expenses associated with extended shipyard projects and increased downtime, both as a result of complying with the enhanced regulations and our customers' requirements. We also lost approximately $1.1 billion of contract backlog associated with the termination of the Deepwater Horizon contract in April 2010 resulting from the loss of the rig and the termination of another drilling contract in December 2011 resulting from the previously mentioned increased downtime. We have recognized estimated losses of $1.9 billion in connection with loss contingencies associated with the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. See Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident. Additionally, in the three years ended December 31, 2012, we incurred cumulative incremental costs, primarily associated with legal expenses for lawsuits and investigations, in the amount of $372 million. Collectively, the lost contract backlog from the incident and from the termination in December 2011, the lost revenues and incremental costs and expenses and other losses have had an effect of greater than $4.0 billion. See "—Contingencies—Insurance matters."

In accordance with our critical accounting policies, 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. 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 declines in actual or anticipated dayrates or other impairment indicators, especially with respect to our High-Specification Jackup fleet, we may be required to recognize losses in future periods as a result of an impairment of the carrying amount of one or more of our asset groups. At December 31, 2012, the carrying amount of our property and equipment was $20.9 billion, representing 61 percent of our total assets. See "—Critical Accounting Policies and Estimates."

Performance and Other Key Indicators

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

	February 14, 2013	October 17, 2012	February 14, 2012
Contract backlog (a)		(In millions)	
High-Specification Floaters			
Ultra-Deepwater Floaters	$19,144	$ 20,238	$ 12,232
Deepwater Floaters	2,127	2,339	2,228
Harsh Environment Floaters	1,942	2,189	2,188
Total High-Specification Floaters	23,213	24,766	16,648
Midwater Floaters	4,145	3,403	2,249
High-Specification Jackups	1,486	1,493	1,051
Total	$28,844	$ 29,662	$ 19,948

(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.

For the year ended December 31, 2012, we added $16.1 billion to our contract backlog for continuing operations, including 10-year drilling contracts for four newbuild dynamically positioned Ultra-Deepwater drillships, which collectively added approximately $7.6 billion to our contract backlog. In addition, we contracted the newbuild Ultra-Deepwater drillship Deepwater Invictus, currently under construction in Korea, for three years, adding another $700 million to our contract backlog.

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At February 14, 2013, the contract backlog and average contractual dayrates for our contract drilling services segment were as follows:

	Total	2013	2014	2015	2016	Thereafter
		For the years ending December 31,				
Contract backlog (a)		(In millions, except average dayrates)				
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 19,144	$ 4,060	$ 3,182	$ 1,703	$ 1,457	$ 8,742
Deepwater Floaters	2,127	969	640	403	115	—
Harsh Environment Floaters	1,942	1,035	763	144	—	—
Total High-Specification Floaters	23,213	6,064	4,585	2,250	1,572	8,742
Midwater Floaters	4,145	1,411	1,645	932	157	—
High-Specification Jackups	1,486	440	478	300	119	149
Total contract backlog	$ 28,844	$ 7,915	$ 6,708	$ 3,482	$ 1,848	$ 8,891
Average-contractual dayrates (b)						
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 527,000	$ 528,000	$ 545,000	$ 532,000	$ 504,000	$ 502,000
Deepwater Floaters	$ 354,000	$ 367,000	$ 337,000	$ 367,000	$ 302,000	$ —
Harsh Environment Floaters	$ 465,000	$ 457,000	$ 472,000	$ 483,000	$ —	$ —
Total High-Specification Floaters	$ 487,000	$ 481,000	$ 492,000	$ 489,000	$ 480,000	$ 502,000
Midwater Floaters	$ 338,000	$ 323,000	$ 352,000	$ 349,000	$ 258,000	$ —
High-Specification Jackups	$ 150,000	$ 150,000	$ 159,000	$ 146,000	$ 137,000	$ 135,000
Total fleet average	$ 396,000	$ 398,000	$ 396,000	$ 377,000	$ 400,000	$ 421,000

(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.

Our contract backlog includes amounts associated with our newbuild units that are currently under construction. 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.

Fleet average daily revenue—The average daily revenue for our contract drilling services segment was as follows:

	Three months ended		
	December 31, 2012	September 30, 2012	December 31, 2011
Average daily revenue (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 514,300	$ 515,000	$ 490,200
Deepwater Floaters	$ 337,100	$ 356,300	$ 315,200
Harsh Environment Floaters	$ 476,400	$ 421,000	$ 463,000
Total High-Specification Floaters	$ 469,300	$ 464,600	$ 446,100
Midwater Floaters	$ 280,300	$ 264,500	$ 264,800
High-Specification Jackups	$ 162,400	$ 154,600	$ 107,300
Total fleet average daily revenue	$ 382,000	$ 376,200	$ 369,900

(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. 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 or classification as held for sale.

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

	Three months ended		
	December 31, 2012	September 30, 2012	December 31, 2011
Revenue efficiency (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	96%	96%	90%
Deepwater Floaters	91%	96%	90%
Harsh Environment Floaters	97%	95%	98%

Total High-Specification Floaters	95%	96%	91%
Midwater Floaters	94%	90%	95%
High-Specification Jackups	95%	97%	93%
Total fleet average revenue efficiency	95%	95%	92%

(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:

	Three months ended		
	December 31, 2012	September 30, 2012	December 31, 2011
Rig utilization (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	94%	95%	88%
Deepwater Floaters	64%	63%	55%
Harsh Environment Floaters	72%	91%	96%
Total High-Specification Floaters	82%	85%	78%
Midwater Floaters	72%	70%	57%
High-Specification Jackups	81%	86%	74%
Total fleet average utilization	79%	80%	72%

(a) Rig utilization is defined as the total number of operating days divided by the total number of available rig calendar days in the measurement period, expressed as a percentage.

Our rig utilization 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 or classification as held for sale.

Results of Operations

Historical 2012 compared to 2011

Following is an analysis of our operating results. See "—Performance and Other Key Indicators—Fleet average daily revenue" for a definition of revenue earning days and average daily revenue. See "—Performance and Other Key Indicators—Utilization" for a definition of utilization.

	Years ended December 31,			
	2012	2011	Change	% Change
	(In millions, except day amounts and percentages)			
Revenue earning days	23,577	20,017	3,560	18%
Utilization	78%	69%		
Average daily revenue	$ 370,300	$ 367,600	$ 2,700	1%
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 and amortization	(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%
Gain on retirement of debt	2	—	2	n/m
Other, net	(50)	(99)	49	(49)%
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
Income (loss) from discontinued operations, net of tax	(1,027)	85	(1,112)	n/m
Net loss	(211)	(5,677)	5,466	(96)%

Net income attributable to noncontrolling interest		8		77		(69)	(90)%
Net loss attributable to controlling interest	$	(219)	$	(5,754)	$	5,535	(96)%

“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 increased revenue earning days as a result of the greater downtime associated with shipyard, mobilization, maintenance, repair and equipment certification projects in the year ended December 31, 2011, a significant portion of which was associated with the post-Macondo regulatory and operating environment, (b) approximately $330 million of increased contract drilling revenues from 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 decreased revenues of approximately $178 million associated with the continuing operations of our drilling management services due to reduced demand for these services in the U.K.

Costs and expenses—Operating and maintenance expenses decreased for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily due to the following: (a) approximately $240 million of decreased costs and expenses associated with the estimated loss contingencies related to the Macondo well incident, (b) approximately $145 million of decreased costs and expenses associated with our drilling management services, and (c) approximately $35 million of decreased costs and expenses related to our integrated services. These decreases were partially offset by (a) $180 million of increased costs and expenses associated with rigs undergoing shipyard, maintenance and repair projects in the year ended December 31, 2012 and (b) $160 million of increased costs and expenses resulting from 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.

Depreciation and amortization 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 on impairment of the customer relationship intangible assets associated with our drilling management services reporting unit.

In the year ended December 31, 2012, we recognized a net gain on disposal of assets of $36 million, primarily related to the completion of sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham. In the year ended December 30, 2011, we recognized a net loss on disposal of assets of $12 million.

Other income and expense—Interest expense 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 losses on foreign exchange of $27 million and a loss of $24 million related to the redeemed noncontrolling interest in TPDI. In the year ended December 31, 2011, we recognized losses on foreign exchange of $99 million, 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, losses on our forward exchange contract, expenses for litigation matters, losses on debt retirements and gains and losses on certain asset disposals and acquisitions. 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. 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. The annual effective tax rate decreased to 17.8 percent from 35.4 percent for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily due to the significant increase in income before income taxes and the foreign 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.

Historical 2011 compared to 2010

Following is an analysis of our operating results. See "—Performance and Other Key Indicators—Fleet average daily revenue" for a definition of revenue earning days and average daily revenue. See "—Performance and Other Key Indicators—Utilization" for a definition of utilization.

	Years ended December 31, 2011	2010	Change	% Change
	(In millions, except day amounts and percentages)			
Revenue earning days	20,017	21,796	(1,779)	(8)%
Utilization	69%	76%		
Average daily revenue	$ 367,600	$ 348,100	$ 19,500	6%
Contract drilling revenues	$ 7,407	$ 7,698	$ (291)	(4)%
Other revenues	620	251	369	n/m
	8,027	7,949	78	1%
Operating and maintenance expense	(6,179)	(4,219)	(1,960)	46%
Depreciation and amortization	(1,109)	(1,009)	(100)	10%
General and administrative expense	(288)	(246)	(42)	17%
Loss on impairment	(5,201)	—	(5,201)	n/m
Gain (loss) on disposal of assets, net	(12)	255	(267)	n/m
Operating income (loss)	(4,762)	2,730	(7,492)	n/m
Other income (expense), net				
Interest income	44	23	21	91%
Interest expense, net of amounts capitalized	(621)	(567)	(54)	10%
Loss on retirement of debt	—	(33)	33	n/m
Other, net	(99)	2	(101)	n/m
Income (loss) from continuing operations before income tax expense	(5,438)	2,155	(7,593)	n/m
Income tax expense	(324)	(292)	(32)	11%
Income (loss) from continuing operations	(5,762)	1,863	(7,625)	n/m
Income (loss) from discontinued operations, net of tax	85	(894)	979	n/m
Net income (loss)	(5,677)	969	(6,646)	n/m
Net income attributable to noncontrolling interest	77	43	34	79%
Net income (loss) attributable to controlling interest	$ (5,754)	$ 926	$ (6,680)	n/m

"n/a" means not applicable.
"n/m" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the following: (a) approximately $505 million of decreased contract drilling revenues due to fewer revenue earning days as a result of shipyard, mobilization, maintenance, repair and equipment certification projects, of which a significant portion was associated with the post-Macondo regulatory and operating environments, (b) approximately $430 million of decreased contract drilling revenues due to reduced drilling activity associated with stacked or idle rigs and (c) approximately $85 million of decreased revenues associated with the sale of GSF Arctic IV, which operated under a short-term bareboat charter in 2010. Partially offsetting these decreases in revenues were (a) $585 million of increased contract drilling revenues earned from the operations of our two Harsh Environment Ultra-Deepwater semisubmersibles acquired in connection with our acquisition of Aker Drilling in October 2011 and our newbuild units that commenced operations in the years ended December 31, 2011 and 2010 and (b) $160 million of increased contract drilling revenues resulting from fewer rigs operating under lower special standby rates in effect during and subsequent to the U.S. Gulf of Mexico drilling moratorium.

Other revenues increased for the year ended December 31, 2011 compared to the year ended December 31, 2010, primarily due to increased revenues of approximately $370 million associated with our drilling management services.

Costs and expenses—Operating and maintenance expenses increased for the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the following: (a) $1.0 billion of increased costs and expenses associated with the estimated loss contingencies related to the Macondo well incident, (b) approximately $775 million of increased costs and expenses associated with rigs undergoing shipyard, maintenance, repair and equipment recertification projects, a significant portion of which was associated with the post-Macondo regulatory and operating environment, (c) approximately $265 million of increased costs and expenses associated with our drilling management services and (d) approximately $175 million of increased costs and expenses resulting from the operations of our two Harsh Environment Ultra-Deepwater semisubmersibles acquired in connection with our acquisition of Aker Drilling in October 2011 and our newbuild units that commenced operations during the years ended December 31, 2011 and 2010. These increases were partially offset by (a) $140 million of decreased costs and expenses related to insurance deductibles and legal costs associated with the Macondo well incident, (b) $140 million of decreased costs and expenses related to lower utilization resulting from additional stacked rigs, and (c) approximately $80 million of decreased costs and expenses associated with the sale of GSF Arctic IV, which operated under a short-term bareboat charter in 2010.

Depreciation and amortization increased primarily due to the following: (a) $36 million of additional depreciation expense associated with two newbuild Ultra-Deepwater Floaters, which commenced operations in 2011, (b) $34 million related to three newbuild Ultra-Deepwater Floaters, which commenced operations in 2010, (c) $11 million related to two rigs acquired in connection with our acquisition of Aker Drilling in October 2011 and (d) $9 million related to implementation of our global Enterprise Resource Planning system.

General and administrative expense increased primarily due to $22 million of acquisition costs incurred in connection with our acquisition of Aker Drilling in the year ended December 31, 2011.

During the year ended December 31, 2011, we recognized an estimated loss of $5.2 billion on impairment of goodwill associated with our contract drilling services reporting unit due to a decline in projected cash flows and market valuations for this reporting unit.

During the year ended December 31, 2011, we recognized a net loss on disposal of assets of $12 million related to sales of rigs and other property and equipment. In the year ended December 31, 2010, we recognized a net gain on disposal of assets of $255 million, including a $267 million gain on insurance recoveries for the loss of Deepwater Horizon that exceeded the carrying amount of the rig. Partially offsetting the gain was a loss of $15 million related to the sale of GSF Arctic II and GSF Arctic IV.

Other income and expense—Interest expense increased in the year ended December 31, 2011 compared to the year ended December 31, 2010, primarily due to $50 million of reduced interest capitalized for our newbuild projects and $83 million of increased interest expense associated with debt issued in the years ended December 31, 2010 and 2011 and debt assumed in our acquisition of Aker Drilling in the year ended December 31, 2011. Partially offsetting these increases was $103 million associated with debt repaid or repurchased in the years ended December 31, 2010 and 2011.

In the year ended December 31, 2010, we recognized a net loss on retirement of debt primarily related to repurchases of the Series B Convertible Senior Notes and Series C Convertible Senior Notes.

In the year ended December 31, 2011, we recognized losses on foreign exchange of $99 million, 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 35.4 percent and 12.5 percent at December 31, 2011 and 2010, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as losses on impairment, losses on our forward exchange contract, expenses for litigation matters, losses on debt retirements and gains and losses on certain asset disposals and acquisitions. 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, 2011 and 2010, the impact of the various discrete period tax items was a net tax expense of $12 million and $45 million, respectively. These discrete tax items, coupled with the excluded income and expense items noted above, resulted in effective tax rates of (6.0) percent and 13.5 percent on income from continuing operations before income tax expense for the years ended December 31, 2011 and 2010, 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. The annual effective tax rate increased to 35.4 percent from 12.5 percent for the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the significant decrease in income before income taxes. With respect to the annual effective tax rate calculation for the year ended December 31, 2011, 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 and Equatorial Guinea. Conversely, the most significant countries in which we operated during this period that impose income taxes based on income before income tax include the U.K., Switzerland, Brazil and the U.S.

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

Discontinued Operations

Standard Jackup and swamp barge contract drilling services—On November 30, 2012, in connection with our efforts to dispose of non-strategic assets, we completed the sale of 38 drilling units to Shelf Drilling in a series of related transactions. Such drilling units included the Standard Jackup GSF Baltic, which was formerly classified as a High-Specification Jackup, the Standard Jackups C.E. Thornton, F.G. McClintock, GSF Adriatic I, GSF Adriatic V, GSF Adriatic VI, GSF Adriatic IX, GSF Adriatic X, GSF Compact Driller, GSF Galveston Key, GSF High Island II, GSF High Island IV, GSF High Island V, GSF High Island VII, GSF High Island IX, GSF Key Gibraltar, GSF Key Hawaii, GSF Key Manhattan, GSF Key Singapore, GSF Main Pass I, GSF Main Pass IV, GSF Parameswara, GSF Rig 105, GSF Rig 124, GSF Rig 141, Harvey H. Ward, J.T. Angel, Randolph Yost, Ron Tappmeyer, Transocean Comet, Trident II, Trident VIII, Trident IX, Trident XII, Trident XIV, Trident XV, Trident XVI and the swamp barge Hibiscus, along with related equipment. Additionally, we have committed to a plan to sell the remaining seven Standard Jackups in our fleet reflecting our decision to discontinue operations associated with the Standard Jackup asset group, a component of our contract drilling services segment.

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 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. As of February 20, 2013, we operated 25 Standard Jackups under operating agreements with 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. The cost to us of providing such operating and transition services may exceed the amounts we receive from Shelf Drilling as compensation for providing such services.

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 the aggregate estimated fair value. As a result, we recognized losses of $744 million and $112 million associated with the impairment of long-lived assets and the goodwill, respectively, associated with this disposal group in the year ended December 31, 2012.

In the year ended December 31, 2012, we also recognized aggregate losses 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 aggregate losses of $28 million, 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, which were classified as assets held for sale at the time of impairment.

During the year ended December 31, 2010, we determined that the Standard Jackup asset group in our contract drilling services reporting unit was impaired due to projected declines in dayrates and utilization rates. As a result, we determined that the carrying amount of the Standard Jackup asset group exceeded its fair value, and in the year ended December 31, 2010, we recognized a loss on impairment of long-lived assets in the amount of $1.0 billion, which had no tax effect.

Caspian Sea contract drilling operations—During the year ended December 31, 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 segment, reflects our decision to discontinue operations in the Caspian Sea. As a result of the sale, we received net cash proceeds of $259 million and recognized a gain on the disposal of the discontinued operations of $169 million. 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 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.

Oil and gas properties—During the year ended December 31, 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, a component of our other operations segment, which comprises the exploration, development and production activities performed by Challenger Minerals Inc., Challenger Minerals (North Sea) Limited and Challenger Minerals (Ghana) Limited. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited for initial net cash proceeds of $24 million and, in May 2012, we received additional net cash proceeds of $10 million from the buyer. In 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 $7 million and $6 million, respectively. In the years ended December 31, 2012 and 2011, we recognized gains on the disposal of these assets in the amounts of $9 million and $14 million, respectively.

See Notes to Consolidated Financial Statements—Note 9—Discontinued Operations.

Liquidity and Capital Resources

Sources and Uses of Cash

At December 31, 2012, we had $5.1 billion in cash and cash equivalents. 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.

In the year ended December 31, 2012, our primary sources of cash were our cash flows from operating activities, proceeds from the issuance of debt and proceeds from asset disposals. Our primary uses of cash were capital expenditures, primarily associated with our newbuild projects, repayments of debt and the payment of the final installment of our distribution of qualifying additional paid-in capital to shareholders.

	Years ended December 31, 2012	Years ended December 31, 2011	Change
	(In millions)		
Cash flows from operating activities			
Net loss	$ (211)	$ (5,677)	$ 5,466
Amortization of drilling contract intangibles	(42)	(45)	3
Depreciation and amortization	1,306	1,451	(145)
Loss on impairment of assets	1,126	5,239	(4,113)
Gain on disposal of assets, net	(118)	(171)	53
Other non-cash items	135	225	(90)
Changes in operating assets and liabilities, net	512	803	(291)
	$ 2,708	$ 1,825	$ 883

Net cash provided by operating activities increased primarily due to greater cash generated from net income after adjusting for non-cash items, including our losses on goodwill impairments of $230 million and $5.2 billion and our accruals of $750 million and $1.0 billion for loss contingencies related to the Macondo well incident in the years ended December 31, 2012 and 2011, respectively. Of the $230 million loss on goodwill impairment, recognized in the year ended December 31, 2012, $112 million was associated with our discontinued operations.

	Years ended December 31, 2012	Years ended December 31, 2011	Change

	(In millions)		
Cash flows from investing activities			
Capital expenditures	$ (1,303)	$ (974)	$ (329)
Capital expenditures for discontinued operations	(106)	(46)	(60)
Investment in business combination, net of cash acquired	—	(1,246)	1,246
Payment for settlement of forward exchange contract, net	—	(78)	78
Proceeds from disposal of assets, net	191	14	177
Proceeds from disposal of assets in discontinued operations, net	789	447	342
Other, net	40	(13)	53
	$ (389)	$ (1,896)	$ 1,507

Net cash used in investing activities decreased primarily due to our acquisition of Aker Drilling and the settlement of a forward currency exchange contract to purchase the Norwegian kroner currency related to the acquisition in the year ended December 31, 2011 with no comparable activity in the year ended December 31, 2012 partially offset by increased proceeds from disposal of assets in the year ended December 31, 2012 compared to the prior year period.

	Years ended December 31, 2012	2011	Change
		(In millions)	
Cash flows from financing activities			
Change in short-term borrowings, net	$ (260)	$ (88)	$ (172)
Proceeds from debt	1,493	2,939	(1,446)
Repayments of debt	(2,282)	(2,409)	127
Proceeds from restricted cash investments	311	479	(168)
Deposits to restricted cash investments	(167)	(523)	356
Proceeds from share issuance, net	—	1,211	(1,211)
Distribution of qualifying additional paid-in capital	(278)	(763)	485
Financing costs	(24)	(83)	59
Other, net	5	(29)	34
	$ (1,202)	$ 734	$ (1,936)

Net cash provided by financing activities decreased primarily due to our proceeds from the issuance of equity in the year ended December 31, 2011 with no comparable activity in the year ended December 31, 2012 and due to reduced proceeds from issuance of debt compared to the prior year period.

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. 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.

The following table presents the historical and projected capital expenditures and other capital additions, including capitalized interest, for our recently completed and ongoing major construction projects conducted during the year ended December 31, 2012:

	Total costs through December 31, 2012	Expected costs for the year ending December 31, 2013	Estimated costs thereafter	Total estimated costs at completion
		(In millions)		
Transocean Honor (a)	$ 262	$ —	$ —	$ 262

Deepwater Asgard (b)	186	525	39	750
Deepwater Invictus (b)	179	512	54	745
Transocean Siam Driller (c)	162	78	—	240
Transocean Andaman (c)	160	85	—	245
Transocean Ao Thai (c)	152	93	—	245
Ultra-Deepwater Floater TBN1 (d)	139	171	520	830
Ultra-Deepwater Floater TBN2 (d)	128	158	499	785
Ultra-Deepwater Floater TBN3 (d)	76	58	651	785
Ultra-Deepwater Floater TBN4 (d)	76	57	652	785
Total	$ 1,520	$ 1,737	$ 2,415	$ 5,672

(a) Transocean Honor, a PPL Pacific Class 400 design High-Specification Jackup, owned through our 70 percent interest in Transocean Drilling Services Offshore Inc. ("TDSOI"), commenced operations in May 2012. The costs presented above represent 100 percent of TDSOI's expenditures in the construction of Transocean Honor. 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, 2012.

(b) Deepwater Asgard and Deepwater Invictus, two Ultra-Deepwater drillships under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, are expected to be ready to commence operations in the second quarter of 2014. Total costs through December 31, 2012 include construction work in progress acquired in connection with our acquisition of Aker Drilling with an aggregate estimated fair value of $272 million.

(c) Transocean Siam Driller, Transocean Andaman and Transocean Ao Thai, three Keppel FELS Super B class design High-Specification Jackups under construction at Keppel FELS' yard in Singapore, are expected to commence operations in the first quarter of 2013, the second quarter of 2013 and the fourth quarter of 2013, respectively.

(d) Our 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 fourth quarter of 2015, the second quarter of 2016, the fourth quarter of 2016, and the first quarter of 2017, respectively.

Capital expenditures, including capitalized interest of $54 million, totaled $1.3 billion in the year ended December 31, 2012, substantially all of which related to our contract drilling services segment. In September 2012, we significantly expanded our expected future capital expenditures with our plan to construct four newbuild Ultra-Deepwater drillships in connection with being awarded 10-year drilling contracts for such drillships. 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, 2013, we expect capital expenditures to be approximately $2.9 billion, including approximately $1.7 billion of cash capital costs 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 new regulatory environment and customer requested capital improvements and equipment for which the customer agrees to reimburse us.

We intend to fund the cash requirements relating to our capital expenditures through available cash balances, cash generated from operations and asset sales. We also have available credit under the Primary Revolving Credit Facilities (see "—Sources and Uses of Liquidity") and may utilize 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 revenue, profitability and financial position."

Dispositions—From time to time, we review possible dispositions of drilling units. During the year ended December 31, 2012, in connection with our efforts to dispose of non-strategic assets of our continuing operations, we completed the sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham and related equipment. In the year ended December 31, 2012, we received net aggregate proceeds of $178 million and recognized an aggregate gain of $51 million on the sale of these drilling units and related equipment associated with our continuing operations. During the year ended December 31, 2012, we recognized a net loss on disposal of other unrelated assets of $15 million.

In November 2012, in connection with our efforts to improve the overall technical capabilities of our fleet and dispose of non-strategic assets, we completed the sale of 37 Standard Jackups and one swamp barge to Shelf Drilling. 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 and discontinued operations to fulfill anticipated obligations, such as scheduled debt maturities or other payments, repayment of debt due within one year, capital expenditures and working capital, shareholder-approved distributions 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 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.

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 equal installments of $0.79 per outstanding share, subject to certain limitations. On March 21, 2012, we paid the final installment of $278 million to shareholders of record as of February 24, 2012. The Board of Directors did not propose a distribution at the 2012 annual general meeting.

On January 3, 2013, we announced a resolution with the DOJ of certain civil and criminal claims, which has been subsequently approved by the courts (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."). However, we are unable to predict the ultimate outcome of the investigations of the Macondo well incident and the DOJ lawsuits related to other civil claims that were not addressed in our resolution with the DOJ. We can give no assurance that the ongoing matters arising out of the Macondo well incident will not adversely affect our liquidity in the future.

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 impact 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 impacted 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.

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 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, 2012, our debt to tangible capitalization ratio, as defined, was 0.5 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. Borrowings under the Primary Revolving Credit Facilities are 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 20, 2013, we had no borrowings outstanding, we had $24 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 20, 2013, 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, beginning April 15, 2013. 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 20, 2013, $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.

We expect to use the net proceeds from the debt offering to fund all or a part of the cost associated with the construction of four newbuild Ultra-Deepwater drillships. See "—Liquidity and Capital Resources—Drilling Fleet."

5% Notes—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.

Convertible Senior Notes—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. In February 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. At February 20, 2013, no Convertible Senior Notes were outstanding.

Callable Bonds—In connection with our acquisition of Aker Drilling, we assumed the obligations related to 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"), issued on February 21, 2011, which are publicly traded on the Oslo Stock Exchange. The FRN Callable Bonds and the 11% Callable Bonds are denominated in Norwegian kroner in the aggregate principal amounts of NOK 940 million and NOK 560 million, respectively. The FRN Callable Bonds bear interest at the Norwegian Interbank Offered Rate plus seven percent. The Callable Bonds require quarterly interest payments and may be redeemed in whole or in part at an amount equal to the outstanding principal plus a certain premium amount and accrued unpaid interest. On January 23, 2013, we provided notice of our intent to redeem the Callable Bonds on March 6, 2013. At February 20, 2013, the total aggregate principal amounts of the FRN Callable Bonds and the 11% Callable Bonds were NOK 940 million and NOK 560 million, equivalent to $168 million and $100 million, respectively, using an exchange rate of NOK 5.60 to US $1.00. See Notes to Consolidated Financial Statements—Note 15—Derivatives and Hedging.

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 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 20, 2013, borrowings of $388 million each were outstanding under Eksportfinans Loan A and Eksportfinans Loan B.

The Eksportfinans Loans require cash collateral to remain on deposit at a certain financial institution through expiration (the “Aker Restricted Cash Investments”). The Aker 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 20, 2013, the aggregate balance of the Aker Restricted Cash Investments was $776 million.

TPDI Credit Facilities—We have 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 (the "TPDI Credit Facilities"). One of our subsidiaries participates in the term loan with an aggregate commitment of $595 million. The senior term loan bears interest at the London Interbank Offered Rate ("LIBOR") plus a margin of 1.45 percent and requires quarterly payments with a final payment in March 2015. The junior term loan and the revolving credit facility bear interest at LIBOR plus a margin of 2.25 percent and 1.45 percent, respectively, and are due in full in March 2015. The TPDI Credit Facilities may be prepaid in whole or in part without premium or penalty. Borrowings under the TPDI Credit Facilities are secured by the Ultra-Deepwater Floaters Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2. The TPDI Credit Facilities contain covenants that require us to maintain a minimum cash balance and available liquidity, a minimum debt service ratio and a maximum leverage ratio. If our Debt Rating falls below investment grade, we would be required to obtain insurance from a source other than our wholly owned captive insurance company within 10 business days. At February 20, 2013, $770 million was outstanding under the TPDI Credit Facilities, of which $385 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on February 20, 2013 was 1.9 percent.

Under the TPDI Credit Facilities, we are required to satisfy certain liquidity requirements, including a requirement to maintain certain cash balances in restricted accounts for the payment of scheduled installments. At February 20, 2013, such restricted cash balances were $2 million. At February 20, 2013, we also had an outstanding letter of credit in the amount of $60 million to satisfy additional liquidity requirements under the TPDI Credit Facilities.

ADDCL Credit Facilities—Angola Deepwater Drilling Company Limited ("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 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. Borrowings under the ADDCL Primary Loan Facility are secured by the Ultra-Deepwater Floater Discoverer Luanda. The ADDCL Primary Loan Facility contains covenants that require ADDCL to maintain certain cash balances to service the debt and also limits ADDCL's ability to incur additional indebtedness, to acquire assets, or to make distributions or other payments. At February 20, 2013, borrowings of $163 million were outstanding under Tranche A at a weighted-average interest rate of 1.2 percent. At February 20, 2013, borrowings of $399 million were outstanding under Tranche C, which were eliminated in consolidation.

ADDCL also has a $90 million secondary credit facility, established under a bank credit agreement 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. Borrowings under the ADDCL Secondary Loan Facility bear 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 payable in full in December 2015 and may be prepaid in whole or in part without premium or penalty. Borrowings 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. In addition, if our Debt Rating falls below investment grade, ADDCL would be required to obtain insurance from a source other than our wholly owned captive insurance company within 10 business days. At

February 20, 2013, borrowings of $80 million were outstanding under the ADDCL Secondary Loan Facility, of which $52 million was provided by one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on February 20, 2013 was 3.4 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 February 20, 2013, ADDCL had restricted cash investments of $27 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 20, 2013, $656 million was outstanding under the capital lease contract.

Consent Decree obligations—Pursuant to a civil consent decree by and among the DOJ and certain of our affiliates (the "Consent Decree") that we entered into on January 3, 2013, we agreed to pay a civil penalty totaling $1.0 billion, plus interest, according to the following schedule: (a) $400 million, plus interest, within 60 days after the date of entry; (b) $400 million, plus interest, within one year after the date of entry; and (c) $200 million, plus interest, within two years after the date of entry. Such interest will accrue from January 3, 2013 at the statutory post-judgment interest rate equal to the weekly average one-year constant maturity U.S. Treasury yield, as published by the Board of Governors of the Federal Reserve System, for the calendar week preceding the date of entry, plus 2.0 percent. The Consent Decree was approved by the court on February 19, 2013, and at the time of such approval, the noncurrent portion of these obligations were reclassified to other long-term liabilities on our consolidated balance sheets.

Plea Agreement obligations—Pursuant to a cooperation guilty plea agreement by and among the DOJ and certain of our affiliates (the "Plea Agreement") that we entered into on January 3, 2013, we are required to pay a criminal fine of $100 million within 60 days of sentencing, which is expected to occur in the first or second quarter of 2013. We also consented to the entry of an order requiring us to pay a total of $150 million to the National Fish & Wildlife Foundation, as follows: $58 million within 60 days of sentencing, $53 million within one year of sentencing and an additional $39 million within two years of sentencing. Such order also requires us to pay $150 million to the National Academy of Sciences as follows: $2 million within 90 days of sentencing, $7 million within one year of sentencing, $21 million within two years of sentencing, $60 million within three years of sentencing and a final payment of $60 million within four years of sentencing. The Plea Agreement was approved by the court on February 14, 2013, and at the time of such approval, these obligations were reclassified from other current liabilities to debt or debt due within one year on our consolidated balance sheets.

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 $3.8 billion at an exchange rate as of the close of trading on February 20, 2013 of $1.00 to CHF 0.93. 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. In the year ended December 31, 2012, we did not purchase shares under our share repurchase program.

We may decide, based upon our ongoing capital requirements, 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 would 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 such company's 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 20, 2013, 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—As of December 31, 2012, our contractual obligations stated at face value, were as follows:

	For the years ending December 31,				
	Total	2013	2014 - 2015	2016 - 2017	Thereafter
			(in millions)		
Contractual obligations					
Debt	$ 11,589	$ 1,034	$ 1,738	$ 2,325	$ 6,492
Debt of consolidated variable interest entities	191	28	91	72	—
Interest on debt (a)	6,265	637	1,202	969	3,457
Capital lease	1,201	66	144	145	846
Operating leases	231	42	62	32	95
Purchase obligations	3,766	1,896	1,196	674	—
Total (b)	$ 23,243	$ 3,703	$ 4,433	$ 4,217	$ 10,890

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(a) Includes interest on consolidated debt.

(b) As of December 31, 2012, our defined benefit pension and other postretirement plans represented an aggregate liability of $642 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 "—Retirement Pension Plans and Other Postretirement Benefit Plans" and Notes to Consolidated Financial Statements—Note 16—Postemployment Benefit Plans.

As of December 31, 2012, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of $581 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 8—Income Taxes.

Subsequent to December 31, 2012, 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 pay $1.4 billion in fines, recoveries and penalties, excluding interest, in scheduled payments over a five-year period through 2017. The Consent Decree and Plea Agreement, pursuant to which our obligations are defined, received court approval in February 2013 and, at the time of such approval, were reclassified from other current liabilities to debt or debt due within one year. See "—Contingencies—Macondo well incident."

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, the U.S., Egypt and Indonesia. 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, 2012, these obligations stated in U.S. dollar equivalents and their time to expiration were as follows:

	For the years ending December 31,				
	Total	2013	2014 - 2015	2016 - 2017	Thereafter
	(in millions)				
Other commercial commitments					
Standby letters of credit (a)	$ 522	$ 463	$ 59	$ —	$ —
Surety bonds	11	11	—	—	—
Total	$ 533	$ 474	$ 59	$ —	$ —

(a) Included in the $522 million outstanding letters of credit at December 31, 2012 were $113 million of letters of credit that we have agreed to retain 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 9—Discontinued Operations). Shelf Drilling is required to reimburse us in the event that surety bonds 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, 2012, the cash investments held by the captive insurance company totaled $250 million, and the amount of such cash investments is expected to range from $270 million to $330 million by December 31, 2013. 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 and currency exchange rates. We do not enter into derivative transactions for speculative purposes; however, we may enter into certain transactions that do not meet the criteria for hedge accounting. See Notes to Consolidated Financial Statements—Note 15—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, 2012				Year ended December 31, 2011			
	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)	$ 89	$ 57	$ 3	$ 149	$ 62	$ 25	$ 1	$ 88
Other comprehensive income (loss)	(32)	31	(4)	(5)	(129)	(51)	1	(179)
Employer contributions	108	49	2	159	70	29	4	103
At end of period:								
Accumulated benefit obligation	$ 1,255	$ 434	$ 58	$ 1,747	$ 1,083	$ 375	$ 53	$ 1,511

Projected benefit obligation	1,452	499	58	2,009	1,260	447	53	1,760
Fair value of plan assets	948	422	—	1,370	769	351	—	1,120
Funded status	(504)	(77)	(58)	(639)	(491)	(96)	(53)	(640)
Weighted-Average Assumptions								
-Net periodic benefit costs								
Discount rate (b)	4.67%	5.43%	4.27%	4.85%	5.49%	5.73%	4.94%	5.53%
Long-term rate of return (c)	7.47%	6.07%	n/a	7.02%	8.49%	6.42%	n/a	7.83%
Compensation trend rate (b)	4.22%	4.61%	n/a	4.32%	4.24%	4.62%	n/a	4.36%
Health care cost trend rate-initial	n/a	n/a	8.08%	8.08%	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)	4.19%	5.37%	3.63%	4.48%	4.66%	4.90%	4.28%	4.71%
Compensation trend rate (b)	4.21%	4.38%	n/a	4.25%	4.22%	4.30%	n/a	4.26%

“n/a” means not applicable.

(a) Net periodic benefit costs were reduced by expected returns on plan assets of $84 million and $86 million in the years ended December 31, 2012 and 2011, 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 2019.

Net periodic benefit cost—In the year ended December 31, 2012, net periodic benefit costs increased by $61 million primarily due to the decline in interest rates as well as unfavorable asset performance. For the year ending December 31, 2013, we expect net periodic benefit costs to decrease by $7 million compared to the net periodic benefit costs recognized in the year ended December 31, 2012 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 $15 million primarily due to a decline in discount rates during 2012.

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, 2012, plan assets of the funded Transocean Plans were favorably impacted by improvements in world equity markets, given the allocation of approximately 59 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, 2012, the fair value of the investments in the funded Transocean Plans increased by $250 million, or 22.4 percent, due to investment returns of $144 million, funding contributions of $91 million, net of benefits paid, and currency revaluations of $15 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, 2012, we contributed $159 million and participants contributed $3 million to the Transocean Plans and the OPEB Plans. In the year ended December 31, 2011, we contributed $103 million and participants contributed $3 million to the Transocean Plans and the OPEB Plans.

For the year ending December 31, 2013, we expect to contribute $50 million to the Transocean Plans and $4 million to the OPEB Plans. These estimated contributions are comprised of $14 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 $24 million to fund expected benefit payments for the unfunded U.S. Plans, unfunded Non-U.S.

Plans and OPEB 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,				
2013	$ 43	$ 28	$ 4	$ 75
2014	47	11	4	62
2015	51	10	4	65
2016	55	11	4	70
2017	59	11	4	74
2018-2022	349	82	22	453

Contingencies

Macondo well incident

On April 22, 2010, the Ultra-Deepwater Floater Deepwater Horizon sank after a blowout of the Macondo well caused a fire and explosion on the rig. 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 BP America Production Co. (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. In the three years ended December 31, 2012, we estimate that the Macondo well incident had a direct and indirect effect of greater than $1.0 billion in lost revenues and incremental costs and expenses associated with extended shipyard projects and increased downtime, both as a result of complying with the enhanced regulations and our customers' requirements. We also lost approximately $1.1 billion of contract backlog associated with the termination of the Deepwater Horizon contract in April 2010 resulting from the loss of the rig and the termination of another drilling contract in December 2011 resulting from the previously mentioned increased downtime. We have recognized estimated losses of $1.9 billion in connection with loss contingencies associated with the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. Additionally, in the three years ended December 31, 2012, we incurred cumulative incremental costs, primarily associated with legal expenses for lawsuits and investigations, in the amount of $372 million. Collectively, the lost contract backlog from the incident and from the termination in December 2011, the lost revenues and incremental costs and expenses and other losses have had an effect of greater than $4.0 billion. See "—Contingencies—Insurance matters."

We have recognized a liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made. 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 contingencies could increase the liabilities we ultimately recognize. As of December 31, 2012 and 2011, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $1.9 billion and $1.2 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 recoverable from insurance. 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 adjust our estimated loss contingencies arising out of the Macondo well incident or 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 and cash flows. In the year ended December 31, 2012, we received $15 million of cash proceeds from insurance recoveries for losses related to the personal injury and fatality claims of our crew and vendors. Additionally, BP received $84 million of cash proceeds from insurance recoveries under our insurance program for recoveries of losses for which we had agreed to contractual indemnity of BP (See "—Contingencies—Contractual indemnity"). The payments made to BP resulted in corresponding reductions of the insurance recoverable asset and contingent liability in the amount of the payment. At December 31, 2012 and 2011, the insurance recoverable asset related to estimated losses primarily for additional personal injury and fatality claims of our crew and vendors that we believe are recoverable from insurance was $141 million and $233 million, respectively, recorded in other assets.

Additionally, our first layer of excess insurers, representing $150 million of insurance coverage, filed interpleader actions on June 17, 2011. 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 interpleader actions have executed a protocol agreement to facilitate the reimbursement and funding of settlements of personal injury and fatality claims of our crew and vendors using insurance funds and claims have been submitted to the court for review. Pending the court's determination of the parties' claims, and with the court's approval, the insurers have made interim reimbursement payments to the parties.

Our second layer of excess insurers, representing $150 million of insurance coverage, filed an interpleader action on July 31, 2012. Effective February 11, 2013, the parties to the second layer interpleader action executed a protocol agreement to facilitate the reimbursement and funding of settlements of personal injury and fatality claims of our crew and vendors using insurance funds. Like the interpleader actions filed by the first layer of excess insurers, the second layer of excess insurers contend that they face multiple, and potentially competing, claims to the relevant insurance proceeds. In this action, 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.

On February 14, 2013, our third layer and fourth layer of excess insurers filed an interpleader action. Like the interpleader actions filed by the first layer and second layer of excess insurers, the third layer and fourth layer of excess insurers contend that they face multiple, and potentially competing, claims to the relevant insurance proceeds. In this action, 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 court has not yet issued any rulings on this action.

On January 3, 2013, we reached 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 pay $1.4 billion in fines, recoveries and penalties, excluding interest, in scheduled payments over a five-year period through 2017.

Pursuant to the Plea Agreement, one of our subsidiaries pled guilty to one misdemeanor count of negligently discharging oil into the U.S. Gulf of Mexico, in violation of the Clean Water Act ("CWA"). The court accepted the guilty plea on February 14, 2013 and imposed the agreed-upon sentence. Pursuant to the Plea Agreement, the court imposed a criminal fine of $100 million to be paid within 60 days of sentencing, and also entered an order requiring us to pay a total of $150 million to the National Fish & Wildlife Foundation, as follows: $58 million within 60 days of sentencing, $53 million within one year of sentencing and an additional $39 million within two years of sentencing. Such order also requires us to pay $150 million to the National Academy of Sciences as follows: $2 million within 90 days of sentencing, $7 million within one year of sentencing, $21 million within two years of sentencing, $60 million within three years of sentencing and a final payment of $60 million within four years of sentencing. As of the date of the court approval, these obligations were reclassified from other current liabilities to debt or debt due within one year on our consolidated balance sheets. Our subsidiary has also agreed to five years of probation. The DOJ has 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 have agreed to continue to cooperate with the Deepwater Horizon Task Force in any ongoing investigation related to or arising from the accident.

Pursuant to the Consent Decree, we agreed to pay a civil penalty totaling $1.0 billion, plus interest, according to the following schedule: (a) $400 million, plus interest, within 60 days after the date of entry; (b) $400 million, plus interest, within one year after the date of entry; and (c) $200 million, plus interest, within two years after the date of entry. Such interest will accrue from January 3, 2013 at the statutory post-judgment interest rate equal to the weekly average one-year constant maturity U.S. Treasury yield, as published by the Board of Governors of the Federal Reserve System, for the calendar week preceding the date of entry, plus 2.0 percent. The Consent Decree was approved by the court on February 19, 2013, and at the time of such approval, the noncurrent portion of these obligations were reclassified to other long-term liabilities on our consolidated balance sheets.

In addition, we agreed to take specified actions relating to operations in U.S. waters and waters above the U.S. outer continental shelf, 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 have agreed to submit a performance plan (the "Performance Plan") for approval by the U.S. within

120 days after the date of entry of the Consent Decree. The Performance Plan will include, among other things, 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 relief 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. has agreed not to sue Transocean Ltd., Transocean Inc., 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, the Emergency Planning and Community Right to Know Act and the Clean Air Act. In addition, the Consent Decree resolves our appeal of the incidents of noncompliance under the OSCLA issued by the BSEE on October 12, 2011 without any admission of liability by us.

The Consent Decree is without prejudice to the rights of the U.S. with respect to all other matters, including certain liabilities under the Oil Pollution Act ("OPA") for removal costs or for damages including 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 assessment. However, the district court previously held that we are not liable under the OPA for damages caused by subsurface discharge from the Macondo well. Assuming that this ruling is upheld on appeal, our natural resources damage assessment liability would be limited to any such damages arising from the above-surface discharge.

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 for five years; (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; and (iv) complied with the other requirements of the Consent Decree, including payment of any stipulated penalties and compliant reporting.

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

On February 25, 2013, we reached an administrative agreement (the “EPA Agreement”) with the EPA. The EPA Agreement resolves 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 has 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, Consent Decree and Plea Agreement. Subject to certain exceptions, the EPA Agreement prohibits us from entering into or engaging in certain business relationships with individuals or entities that are debarred, suspended, proposed for debarment or similarly restricted. The EPA Agreement has a five-year term.

Many of the Macondo well related claims are pending in the U.S. District Court, Eastern District of Louisiana (the “MDL Court”). The first phase of a three-phase trial was originally scheduled to commence in March 2012. 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) 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. After giving consideration to the BP/PSC Settlement, the MDL Court ordered that the first phase of the trial, at which liability will be determined, be rescheduled for February 2013. The MDL Court subsequently issued an order with a projected trial date of June 2013 for the second phase of the trial, which will address conduct related to stopping the release of hydrocarbons between April 22, 2010 and approximately September 19, 2010 and seek to determine the amount of oil actually released during the period. Due to changes in the discovery schedule, the second phase of trial is being rescheduled for September 2013. There can be no assurance as to the outcome of the trial, as to the timing of any phase of trial, that we will not enter into a settlement 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 assurances as to the estimated costs, insurance recoveries, or other actions that will result from the Macondo well incident. See Notes to Consolidated Financial Statements Note 17—Commitments and Contingencies and "Part I. Item 1A. Risk Factors—Risks Related to Our Business."

Insurance matters

Our hull and machinery and excess liability insurance program is comprised of commercial market and captive insurance policies. We periodically evaluate our insurance limits and self-insured retentions. As of December 31, 2012, the insured value of our drilling rig fleet was approximately $29.3 billion, excluding our rigs under construction.

Hull and machinery coverage—Under the hull and machinery program, effective May 1, 2012, 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 costs incurred to mitigate damage to a rig up to an amount equal to 25 percent of a rig's insured value. Also subject to the same shared deductible, we have additional coverage for wreck removal for up to 25 percent of a rig's insured value, with any excess generally covered to the extent of our remaining excess liability coverage.

Excess liability coverage—Effective May 1, 2012, we carry $775 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 $825 million.

Other insurance coverage—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.

We have elected to self-insure operators extra expense coverage for ADTI. This coverage provides protection against expenses related to well control, pollution and redrill liability associated with blowouts. ADTI's customers assume, and indemnify ADTI for, liability associated with blowouts in excess of a contractually agreed amount, generally $50 million.

We generally do not have commercial market insurance coverage for our fleet for loss of revenues, unless it is contractually required, or for physical damage losses, including liability for wreck removal expenses, which are caused by named windstorms in the U.S. Gulf of Mexico.

See Notes to Consolidated Financial Statements Note 17—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.

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 8—Income Taxes.

Regulatory matters

In June 2007, GlobalSantaFe's management retained outside counsel to conduct an internal investigation of its Nigerian and West African operations, focusing on brokers who handled customs matters with respect to its affiliates operating in those jurisdictions and whether those brokers have fully complied with the U.S. Foreign Corrupt Practices Act ("FCPA") and local laws. GlobalSantaFe commenced its investigation following announcements by other oilfield service companies that they were independently investigating the FCPA implications of certain actions taken by third parties in respect of customs matters in connection with their operations in Nigeria, as well as another company's announced settlement implicating a third-party handling customs matters in Nigeria. In each case, the customs broker was reported to be Panalpina Inc., which GlobalSantaFe used to obtain temporary import permits for its rigs operating offshore Nigeria. GlobalSantaFe voluntarily disclosed its internal investigation to the DOJ and the U.S. Securities and Exchange Commission ("SEC") and, at their request, expanded its investigation to include the activities of its customs brokers in certain other African countries. The investigation focused on whether the brokers fully complied with the requirements of their contracts, local laws and the FCPA and GlobalSantaFe's possible involvement in any inappropriate or illegal conduct in connection with such brokers. In late November 2007, GlobalSantaFe received a subpoena from the SEC for documents related to its investigation. In addition, the SEC advised GlobalSantaFe that it had issued a formal order of investigation.

On July 25, 2007, our legal representatives met with the DOJ in response to a notice we received requesting such a meeting regarding our engagement of Panalpina Inc. for freight forwarding and other services in the U.S. and abroad. The DOJ informed us that it was conducting an investigation of alleged FCPA violations by oil service companies who used Panalpina Inc. and other brokers in Nigeria and other parts of the world. We developed an investigative plan that allowed us to review and produce relevant and responsive information requested by the DOJ and SEC. The investigation was expanded to include one of our agents for Nigeria. This investigation and the legacy GlobalSantaFe investigation were conducted by outside counsel who reported directly to the audit committee of our board of directors. The investigation focused on whether the agent and the customs brokers fully complied with the terms of their respective agreements, the FCPA and local laws and the company's and its employees' possible involvement in any inappropriate or illegal conduct in connection with such brokers and agent. Our outside counsel coordinated their efforts with the DOJ and the SEC with respect to the implementation of our investigative plan, including keeping the DOJ and SEC apprised of the scope and details of the investigation and producing relevant information in response to their requests. The SEC also issued a formal order of investigation in this case and issued a subpoena for further information.

On November 4, 2010, we reached a settlement with the SEC and the DOJ with respect to certain charges relating to the anti-bribery and books and records provisions of the FCPA. In November 2010, under the terms of the settlements, we paid a total of approximately $27 million in penalties, interest and disgorgement of profits. We have also consented to the entry of a civil injunction in two SEC actions and have entered into a three-year deferred prosecution agreement with the DOJ (the "DPA"). In connection with the DPA, we have agreed to implement and maintain certain internal controls, policies and procedures. For the duration of the DPA, we are also obligated to provide an annual written report to the DOJ of our efforts and progress in maintaining and enhancing our compliance policies and procedures. In the event the DOJ determines that we have knowingly violated the terms of the DPA, the DOJ may impose an extension of the term of the agreement or, if the DOJ determines we have breached the DPA, the DOJ may pursue criminal charges or a civil or administrative action against us. The DOJ may also find, in its sole discretion, that a change in circumstances has eliminated the need for the corporate compliance reporting obligations of the DPA and may terminate the DPA prior to the three-year term.

Our internal compliance program has detected a potential violation of U.S. sanctions regulations in connection with the shipment of goods to our operations in Turkmenistan. Goods bound for our rig in Turkmenistan were shipped through Iran by a freight forwarder. Iran is subject to a number of economic regulations, including sanctions administered by the U.S. Treasury Department's Office of Foreign Assets Control ("OFAC"), and comprehensive restrictions on the export and re-export of U.S.-origin items to Iran. Iran has been designated as a state sponsor of terrorism by the U.S. State Department. Failure to comply with applicable laws and regulations relating to sanctions and export restrictions may subject us to criminal sanctions and civil remedies, including fines, denial of export privileges, injunctions or seizures of our assets. We have self-reported the potential violation to OFAC and retained outside counsel who conducted an investigation of the matter and submitted a report to OFAC.

In 2010, we received and responded to an administrative subpoena from OFAC concerning our previous operations in Myanmar and a follow-up administrative subpoena from OFAC with questions relating to the previous Myanmar operations subpoena response and the self-reported shipment through Iran matter. We responded promptly to their request for information and affirmed that we had not violated applicable laws.

In November 2012, we received a cautionary letter from OFAC indicating that it would not pursue any penalties regarding the shipment of goods through Iran by a freight forwarder or our previous operations in Myanmar and that their reviews regarding both matters have been finalized, unless new or additional information warrant renewed attention. We do not expect any new or additional information and consider these matters to be closed with a positive outcome, without penalty.

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, 2012.

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. We presented Quantum's interest in TPDI as redeemable noncontrolling interest on our consolidated balance sheets since 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.

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. 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. On May 31, 2012, we issued 8.7 million shares to Quantum in a non-cash exchange for its interest in TPDI, and as a result, TPDI became our wholly owned subsidiary. The put option agreement, among other things, restricts Quantum's sale of our shares until May 29, 2013. In August 2012, we paid $72 million as the final cash settlement, representing 50 percent of TPDI's working capital at May 29, 2012.

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, judgments and assumptions that affect the amounts reported on the consolidated financial statements and disclosed in the accompanying notes. 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, foreign 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, 2012, the liability for estimated tax exposures in our jurisdictions of operation was approximately $581 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, 2012, 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 $230 million would be payable upon distribution of all previously unremitted earnings at December 31, 2012.

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, 2010, 2011 and 2012.

See Notes to Consolidated Financial Statements—Note 8—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 the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. 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 contingencies could increase the liabilities we ultimately recognize. As of December 31, 2012 and 2011, the liability for estimated loss contingencies that we believe are probable and for which a reasonable estimate can be made was $1.9 billion and $1.2 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 recoverable 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, 2012 and 2011, the insurance recoverable asset related to estimated losses primarily for additional personal injury and family claims of our crew and vendors that we believe are recoverable from insurance was $141 million and $233 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 and expected insurance recoveries 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 and cash flows.

See Notes to Consolidated Financial Statements—Note 17—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 determine the fair value of each reporting unit, we use a combination of valuation methodologies, including 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 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 on impairment in the amount of $5.2 billion, representing our best estimate, which had no tax effect. In the year ended December 31, 2012, we completed our analysis and recognized an incremental adjustment to our original estimate in the amount of $118 million, which had no tax effect.

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, which had no tax effect.

In each of these cases, we estimated the implied fair value of the goodwill using a variety of valuation methods, including 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 availability and dayrates.

In the years ended December 31, 2012 and 2010, 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, 2012, the carrying amount of goodwill was $3.0 billion, representing nine percent of our total assets. See Notes to Consolidated Financial Statements—Note 7—Intangible Asset Impairments, Note 9—Discontinued Operations and Note 13—Goodwill ar Other Intangible 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. 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 $110 million. A hypothetical one-year decrease would cause an increase in our annual depreciation expense of approximately $136 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.

The carrying amount of our property and equipment was $20.9 billion as of December 31, 2012, representing 61 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 " Retirement 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. For each percentage point the expected long-term rate of return assumption is lowered, pension expense would increase by approximately $13 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. For each one-half percentage point the discount rate is lowered, net periodic benefit costs would increase by approximately $25 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, our long-term and short-term debt, and our derivative instruments. For our restricted cash investments and debt instruments, the following table presents the principal cash flows and related weighted-average interest rates by contractual maturity date. For our derivative instruments, including interest rate swaps and cross-currency swaps, the following table presents the notional amounts and weighted-average interest rates by contractual maturity dates. 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)							Fair Value (b)
	2013	2014	2015	2016	2017	Thereafter	Total	
Restricted cash investments								
Fixed rate (NOK)	$ 152	$ 152	$ 153	$ 153	$ 153	$ 38	$ 801	$ 843
Average interest rate	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%		
Debt								
Fixed rate (USD)	$ 831	$ 22	$ 1,123	$ 1,026	$ 777	$ 6,994	$ 10,773	$ (12,371)
Average interest rate	4.95%	7.76%	5.01%	5.12%	2.69%	6.46%		
Fixed rate (NOK)	$ 152	$ 152	$ 153	$ 253	$ 153	$ 38	$ 901	$ (948)
Average interest rate	4.15%	4.15%	4.15%	6.87%	4.15%	4.15%		
Variable rate (USD)	$ 70	$ 70	$ 263	$ —	$ —	$ —	$ 403	$ (403)
Average interest rate	1.76%	1.76%	2.01%	—%	—%	—%		
Variable rate (NOK)	$ —	$ —	$ —	$ 169	$ —	$ —	$ 169	$ (177)
Average interest	—%	—%	—%	8.96%	—%	—%		

rate								
Debt of consolidated variable interest entities								
Variable rate (USD)	$ 28	$ 30	$ 61	$ 35	$ 37	$ —	$ 191	$ (191)
Average interest rate	1.25%	1.25%	2.27%	1.25%	1.25%	—%		
Interest rate swaps								
Fixed to variable (USD)	$ 750	$ —	$ —	$ —	$ —	$ —	$ 750	$ 2
Average pay rate	3.48%	—%	—%	—%	—%	—%		
Average receive rate	5.17%	—%	—%	—%	—%	—%		
Variable to fixed (USD)	$ 70	$ 70	$ 263	$ —	$ —	$ —	$ 403	$ (13)
Average pay rate	2.34%	2.34%	2.34%	—%	—%	—%		
Average receive rate	0.31%	0.31%	0.31%	—%	—%	—%		
Cross-currency swaps								
Receive NOK / pay USD	$ —	$ —	$ —	$ 102	$ —	$ —	$ 102	$ 1
Average pay rate	—%	—%	—%	8.93%	—%	—%		
Average receive rate	—%	—%	—%	11.00%	—%	—%		

(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. We also hold certain derivative instruments that are not designated as hedges. See Notes to Consolidated Financial Statements—Note 15—Derivatives and Hedging.

(b) Stated amounts represent the fair value of the asset (liability) as of December 31, 2012.

Interest Rate Risk

At December 31, 2012 and 2011, the face value of our variable-rate debt was approximately $1.1 billion and $2.5 billion, which represented nine percent and 19 percent of the face value of our total debt, respectively, after the effect of our hedging activities. At December 31, 2012, our variable-rate debt, excluding the effect of our hedging activities, primarily 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, 2012 and 2011, a hypothetical one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of approximately $11 million and $25 million, respectively.

At December 31, 2012 and 2011, the fair value of our debt was $14.1 billion and $13.9 billion, respectively. The $0.2 billion increase was primarily due to the issuance of new senior notes in the amount of $1.5 billion and an increase of $0.4 billion related to the increased market valuation of the fair value of our outstanding debt, partially offset by the repurchase of the Series C Convertible Senior Notes in the amount of $1.7 billion during the year ended December 31, 2012.

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, 2012 and 2011, a hypothetical one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $51 million and $40 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 foreign 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 foreign exchange derivative instruments, including forward exchange contracts or spot purchases, to mitigate currency exchange risk.

At December 31, 2012, we had NOK 6.0 billion aggregate principal amount of debt obligations. Certain of these Norwegian krone-denominated debt instruments are secured by a corresponding amount of Norwegian krone-denominated restricted cash investments. Additionally, we had certain cross-currency swaps, which have been designated as a cash flow hedge of the Callable Bonds, which are denominated in Norwegian kroner. At December 31, 2012 and 2011, after consideration of these currency exchange rate risk management strategies, we had approximately NOK 940 million aggregate principal amount of debt obligations that were exposed to currency exchange rate risk. Based on the Norwegian krone-denominated debt instruments outstanding as of December 31, 2012 and 2011, a hypothetical one percentage point change in the currency exchange rates would result in a corresponding change in annual interest expense of less than $1 million.

On January 23, 2013, we provided notice of our intent to redeem the Callable Bonds on March 6, 2013. In connection with the redemption of the Callable Bonds, we also expect to terminate the related cross-currency swaps.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Derivative Instruments," and "Item 8. Financial Statements and Supplemental Data—Notes to Consolidated Financial Statements—Note 15—Derivatives and Hedging."

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, 2012. In making this assessment, management used the criteria for internal control over financial reporting described in Internal Control-Integrated Framework issued 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, 2012, 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 as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2012, 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, 2012 and 2011, 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, 2012, and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 1, 2013

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 as of December 31, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 1, 2013

TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share data)

	Years ended December 31, 2012	2011	2010
Operating revenues			
Contract drilling revenues	$ 8,773	$ 7,407	$ 7,698
Other revenues	423	620	251
	9,196	8,027	7,949
Costs and expenses			
Operating and maintenance	6,106	6,179	4,219
Depreciation and amortization	1,123	1,109	1,009
General and administrative	282	288	246
	7,511	7,576	5,474
Loss on impairment	(140)	(5,201)	—
Gain (loss) on disposal of assets, net	36	(12)	255
Operating income (loss)	1,581	(4,762)	2,730
Other income (expense), net			
Interest income	56	44	23
Interest expense, net of amounts capitalized	(723)	(621)	(567)
Gain (loss) on retirement of debt	2	—	(33)
Other, net	(50)	(99)	2
	(715)	(676)	(575)
Income (loss) from continuing operations before income tax expense	866	(5,438)	2,155
Income tax expense	50	324	292
Income (loss) from continuing operations	816	(5,762)	1,863
Income (loss) from discontinued operations, net of tax	(1,027)	85	(894)
Net income (loss)	(211)	(5,677)	969
Net income attributable to noncontrolling interest	8	77	43
Net income (loss) attributable to controlling interest	$ (219)	$ (5,754)	$ 926
Earnings (loss) per share-basic			
Earnings (loss) from continuing operations	$ 2.27	$ (18.14)	$ 5.66
Earnings (loss) from discontinued operations	(2.89)	0.26	(2.78)
Earnings (loss) per share	$ (0.62)	$ (17.88)	$ 2.88
Earnings (loss) per share-diluted			
Earnings (loss) from continuing operations	$ 2.27	$ (18.14)	$ 5.66
Earnings (loss) from discontinued operations	(2.89)	0.26	(2.78)
Earnings (loss) per share	$ (0.62)	$ (17.88)	$ 2.88

Weighted-average shares outstanding			
Basic	356	322	320
Diluted	356	322	320

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)

	Years ended December 31, 2012	2011	2010
Net income (loss)	$ (211)	$ (5,677)	$ 969
Other comprehensive income (loss) before income taxes			
Unrecognized components of net periodic benefit costs	(52)	(204)	(8)
Unrecognized gain (loss) on derivative instruments	3	(13)	(29)
Unrecognized loss on marketable securities	—	(13)	—
Recognized components of net periodic benefit costs	47	25	16
Recognized (gain) loss on derivative instruments	(1)	11	12
Recognized loss on marketable securities	2	13	—
Other comprehensive income (loss) before income taxes	(1)	(181)	(9)
Income taxes related to other comprehensive income (loss)	(7)	13	(9)
Other comprehensive income (loss), net of income taxes	(8)	(168)	(18)
Total comprehensive income (loss)	(219)	(5,845)	951
Total comprehensive income attributable to noncontrolling interest	8	73	22
Total comprehensive income (loss) attributable to controlling interest	$ (227)	$ (5,918)	$ 929

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In millions, except share data)

	December 31, 2012	December 31, 2011
Assets		
Cash and cash equivalents	$ 5,134	$ 4,017
Accounts receivable, net		
Trade	1,940	2,049
Other	260	127
Materials and supplies, net	610	529
Assets held for sale	179	26
Deferred income taxes, net	142	142
Other current assets	382	646
Total current assets	8,647	7,536
Property and equipment	26,967	24,833
Property and equipment of consolidated variable interest entities	1,092	2,252
Less accumulated depreciation	7,179	6,297
Property and equipment, net	20,880	20,788
Goodwill	2,987	3,217
Other assets	1,741	3,491
Total assets	$ 34,255	$ 35,032
Liabilities and equity		
Accounts payable	$ 1,047	$ 880
Accrued income taxes	116	86
Debt due within one year	1,339	1,942
Debt of consolidated variable interest entities due within one year	28	245
Other current liabilities	2,933	2,375
Total current liabilities	5,463	5,528
Long-term debt	10,929	10,756
Long-term debt of consolidated variable interest entities	163	593
Deferred income taxes, net	366	487
Other long-term liabilities	1,604	1,925
Total long-term liabilities	13,062	13,761
Commitments and contingencies		
Redeemable noncontrolling interest	—	116
Shares, CHF 15.00 par value, 402,282,355 authorized, 167,617,649 conditionally authorized at December 31,	5,130	4,982

2012 and 2011; 373,830,649 and 365,135,298 issued at December 31, 2012 and 2011, respectively; and 359,505,251 and 349,805,793 outstanding at December 31, 2012 and 2011, respectively		
Additional paid-in capital	7,521	7,211
Treasury shares, at cost, 2,863,267 held at December 31, 2012 and 2011	(240)	(240)
Retained earnings	3,855	4,180
Accumulated other comprehensive loss	(521)	(496)
Total controlling interest shareholders' equity	15,745	15,637
Noncontrolling interest	(15)	(10)
Total equity	15,730	15,627
Total liabilities and equity	$ 34,255	$ 35,032

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(In millions)

	Years ended December 31,			Years ended December 31,		
	2012	2011	2010	2012	2011	2010
Shares		Shares			Amount	
Balance, beginning of period	350	319	321	$ 4,982	$ 4,482	$ 4,472
Issuance of shares under share-based compensation plans	1	1	1	14	12	10
Issuance of shares in exchange for redeemable noncontrolling interest	9	—	—	134	—	—
Issuance of shares in public offering	—	30	—	—	488	—
Purchases of shares held in treasury	—	—	(3)	—	—	—
Balance, end of period	360	350	319	$ 5,130	$ 4,982	$ 4,482
Additional paid-in capital						
Balance, beginning of period				$ 7,211	$ 7,504	$ 7,407
Share-based compensation				97	95	102
Issuance of shares under share-based compensation plans				(17)	(18)	(11)
Issuance of shares in exchange for redeemable noncontrolling interest				233	—	—
Issuance of shares in public offering, net of issue costs				—	671	—
Obligation for distribution of qualifying additional paid-in capital				—	(1,041)	—
Other, net				(3)	—	6
Balance, end of period				$ 7,521	$ 7,211	$ 7,504
Treasury shares, at cost						
Balance, beginning of period				$ (240)	$ (240)	$ —
Purchases of shares held in treasury				—	—	(240)
Balance, end of period				$ (240)	$ (240)	$ (240)
Retained earnings						
				$ 4,180	$ 9,934	$ 9,008

Balance, beginning of period			
Net income (loss) attributable to controlling interest	(219)	(5,754)	926
Fair value adjustment of redeemable noncontrolling interest	(106)	—	—
Balance, end of period	$ 3,855	$ 4,180	$ 9,934
Accumulated other comprehensive loss			
Balance, beginning of period	$ (496)	$ (332)	$ (335)
Other comprehensive income (loss) attributable to controlling interest	(8)	(164)	3
Reclassification from redeemable noncontrolling interest	(17)	—	—
Balance, end of period	$ (521)	$ (496)	$ (332)
Total controlling interest shareholders’ equity			
Balance, beginning of period	$ 15,637	$ 21,348	$ 20,552
Total comprehensive income (loss) attributable to controlling interest	(227)	(5,918)	929
Share-based compensation	97	95	102
Issuance of shares under share-based compensation plans	(3)	(6)	(1)
Issuance of shares in exchange for redeemable 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	—	(1,041)	—
Purchases of shares held in treasury	—	—	(240)
Other, net	(3)	—	6
Balance, end of period	$ 15,745	$ 15,637	$ 21,348
Noncontrolling interest			
	$ (10)	$ (8)	$ 7

Balance, beginning of period			
Total comprehensive income (loss) attributable to noncontrolling interest	(5)	(2)	7
Reclassification of redeemable noncontrolling interest	—	—	(26)
Other, net	—	—	4
Balance, end of period	$ (15)	$ (10)	$ (8)
Total equity			
Balance, beginning of period	$ 15,627	$ 21,340	$ 20,559
Total comprehensive income (loss)	(232)	(5,920)	936
Share-based compensation	97	95	102
Issuance of shares under share-based compensation plans	(3)	(6)	(1)
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	—	(1,041)	—
Purchases of shares held in treasury	—	—	(240)
Other, net	(3)	—	(16)
Balance, end of period	$ 15,730	$ 15,627	$ 21,340

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income (loss)	$ (211)	$ (5,677)	$ 969
Adjustments to reconcile to net cash provided by operating activities:			
Amortization of drilling contract intangibles	(42)	(45)	(98)
Depreciation and amortization	1,123	1,109	1,009
Depreciation and amortization of assets in discontinued operations	183	342	580
Share-based compensation expense	97	95	102
Loss on impairment	140	5,201	—
Loss on impairment of assets in discontinued operations	986	38	1,012
(Gain) loss on disposal of assets, net	(36)	12	(255)
Gain on disposal of assets in discontinued operations, net	(82)	(183)	(2)
Amortization of debt issue costs, discounts and premiums, net	68	125	189
Deferred income taxes	(133)	(62)	(104)
Other, net	72	144	(1)
Changes in deferred revenue, net	(54)	(16)	205
Changes in deferred expenses, net	85	(61)	(79)
Changes in operating assets and liabilities	512	803	379
Net cash provided by operating activities	2,708	1,825	3,906
Cash flows from investing activities			
Capital expenditures	(1,303)	(974)	(1,349)
Capital expenditures for discontinued operations	(106)	(46)	(42)
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	191	14	60
Proceeds from disposal of assets in discontinued operations, net	789	447	—
Proceeds from insurance recoveries for loss of drilling unit	—	—	560
Proceeds from sale of marketable securities	—	—	37
Other, net	40	(13)	13
Net cash used in investing activities	(389)	(1,896)	(721)

Cash flows from financing activities			
Changes in short-term borrowings, net	(260)	(88)	(193)
Proceeds from debt	1,493	2,939	2,054
Repayments of debt	(2,282)	(2,409)	(2,565)
Proceeds from restricted cash investments	311	479	—
Deposits to restricted cash investments	(167)	(523)	—
Proceeds from share issuance	—	1,211	—
Distribution of qualifying additional paid-in capital	(278)	(763)	—
Purchases of shares held in treasury	—	—	(240)
Financing costs	(24)	(83)	(15)
Other, net	5	(29)	(2)
Net cash provided by (used in) financing activities	(1,202)	734	(961)
Net increase in cash and cash equivalents	1,117	663	2,224
Cash and cash equivalents at beginning of period	4,017	3,354	1,130
Cash and cash equivalents at end of period	$ 5,134	$ 4,017	$ 3,354

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, 2012, we owned or had partial ownership interests in and operated 82 mobile offshore drilling units associated with our continuing operations. As of this date, our fleet consisted of 48 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters, and nine High-Specification Jackups. We also had six Ultra-Deepwater drillships and three High-Specification Jackups under construction or under contract to be constructed. See Note 12—Drilling Fleet.

We also provide oil and gas drilling management services, drilling engineering and drilling project management services through Applied Drilling Technology Inc., our wholly owned subsidiary, and through ADT International, a division of one of our United Kingdom ("U.K.") subsidiaries (together, "ADTI"). ADTI conducts drilling management services primarily either on a dayrate or on a completed-project, fixed-price or turnkey basis.

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, 2012, we operated 25 Standard Jackups under operating agreements with Shelf Drilling. See Note 9—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 9—Discontinued Operations.

In March 2011, we engaged an unaffiliated advisor to coordinate the sale of the assets 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 9—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 and other intangible assets, 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.

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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 6—Variable Interest Entities.

In the year ended December 31, 2012, we did not have interests in any unconsolidated entities for which we earned equity in earnings. In the years ended December 31, 2011 and 2010, we recognized equity in earnings of unconsolidated entities in the amount of $5 million and $8 million, respectively. At December 31, 2012 and 2011, our investments in and advances to unconsolidated affiliates had carrying amounts of less than $1 million.

Business combination—In connection with our acquisition of Aker Drilling ASA ("Aker Drilling), we applied the acquisition method of accounting. Accordingly, we recorded the acquired assets and assumed liabilities at fair value and recognized goodwill to the extent the fair value of the business acquired exceeded the fair value of the net assets. We estimated the fair values of the acquired assets and assumed liabilities as of the date of the acquisition. See Note 5—Business Combination.

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 our Standard Jackup and swamp barge asset groups, components of our contract drilling services segment, and the operations of our U.S. Gulf of Mexico drilling management services, a component of our drilling management services 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 9—Discontinued Operations.

Operating revenues and expenses—We recognize operating revenues as they are earned, based on contractual dayrates or on a fixed-price basis. In connection with drilling contracts, we may receive revenues for preparation and mobilization of equipment and personnel or for capital improvements to rigs. In connection with new drilling contracts, revenues earned and incremental costs incurred directly related to contract preparation and mobilization are deferred and recognized over the primary contract term of the drilling project using the straight-line method. Our policy to amortize the fees related to contract preparation, mobilization and capital upgrades on a straight-line basis over the estimated firm period of drilling 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 account for loss contracts as the losses are incurred. Costs of relocating drilling units without contracts to more promising market areas are expensed as incurred. Upon completion of drilling contracts, any demobilization fees received are reported in income, as are any related expenses. Capital upgrade revenues received are deferred and recognized over the primary contract term of the drilling project. The actual cost incurred for the capital upgrade is depreciated over the estimated useful life of the asset. We incur periodic survey and drydock costs in connection with obtaining regulatory certification to operate our rigs and well control systems on an ongoing basis. Costs associated with these certifications are deferred and amortized on a straight-line basis over the period until the next survey.

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 on a straight-line basis over the respective contract period and include such revenues in contract drilling revenues on our consolidated statements of operations. In the years ended December 31, 2012, 2011 and 2010, we recognized contract drilling intangible revenues of $42 million, $45 million and $98 million, respectively. See Note 13—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 consider customer reimbursable revenues to be billings to our customers for reimbursement of certain equipment, materials and supplies, third-party services, employee bonuses and other expenses that we recognize in operating and maintenance expense, the result of which has little or no effect on operating income.

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 time-based restricted shares and deferred units granted or modified, 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 market-based deferred units granted or modified, 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. Tax deduction benefits for awards in excess of recognized compensation costs are reported as a financing cash flow. In the years ended December 31, 2012, 2011 and 2010, share-based compensation expense was $97 million, $95 million and $102 million, respectively. In the years ended December 31, 2012, 2011 and 2010, income tax benefit on share-based compensation expense was $12 million, $16 million, and $13 million, respectively. See Note 20—Share-Based Compensation Plans.

Capitalized interest—We capitalize interest costs for qualifying construction and upgrade projects. In the years ended December 31, 2012, 2011 and 2010, we capitalized interest costs on construction work in progress of $54 million, $39 million and $89 million, respectively.

Foreign currency—The majority of our revenues and expenditures are denominated in U.S. dollars to limit our exposure to currency exchange rate fluctuations, resulting in the use of the U.S. dollar as the functional currency for all of our operations. We recognize foreign currency exchange gains and losses in other, net. In the years ended December 31, 2012, 2011 and 2010, we recognized net foreign currency exchange gains (losses) of $(27) million, $(99) million and

$1 million, respectively. See Note 15—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 provide a valuation allowance to offset deferred tax assets for 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. We provide 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 the provisions and benefits resulting from changes to those liabilities are included in our annual tax provision 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 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 8—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, 2012, the aggregate carrying amount of our restricted cash investments was $857 million, of which $195 million and $662 million was classified in other current assets and other assets, respectively. At December 31, 2011, the aggregate carrying amount of our restricted cash investments was $934 million, of which $182 million and $752 million was classified in other current assets and other assets, respectively. See Note 14—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 major customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. At December 31, 2012 and 2011, the allowance for doubtful accounts was $20 million and $28 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, 2012 and 2011, the allowance for obsolescence was $66 million and $73 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, 2012 and 2011, assets held for sale were $179 million and $26 million, respectively. See Note 9—Discontinued Operations.

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, 2012, the aggregate carrying amount of our property and equipment represented approximately 61 percent of our total assets.

We compute depreciation using the straight-line method after allowing for salvage values. We capitalize expenditures for renewals, replacements and improvements, and we expense maintenance and repair costs as incurred. 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.

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, and we may extend the useful life when events and circumstances indicate a drilling unit can operate beyond its remaining useful life. 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. During the year ended December 31, 2010, we adjusted the useful lives for five rigs, extending the estimated useful lives from between 20 and 36 years to between 25 and 39 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, 2012, 2011 and 2010, the changes in estimated useful lives of these rigs resulted in a reduction in annual depreciation expense of $27 million ($0.08 per diluted share from continuing operations), $2 million ($0.01 per diluted share from continuing operations) and $23 million ($0.07 per diluted share from continuing operations), 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 combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. For our drilling management services customer relationships asset, we estimate fair value using the excess earnings method, which applies 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 on impairment of $22 million ($17 million, or $0.05 per diluted share, net of tax).

Goodwill and other indefinite-lived intangible assets—We conduct impairment testing for our goodwill and other indefinite-lived intangible assets 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 or the indefinite-lived intangible asset is 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 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 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 on impairment, representing our best estimate, in the amount of $5.2 billion ($16.15 per diluted share from continuing operations), which had no tax effect. In the three months ended March 31, 2012, we completed our analysis and recognized an incremental adjustment to our original estimate in the amount of $118 million ($0.33 per diluted share from continuing operations), which had no tax effect. As a result of our annual goodwill impairment test in the years ended December 31, 2012 and 2010, we concluded that goodwill was not impaired. See Note 7—Intangible Asset Impairments and Note 13—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 15—Derivatives and Hedging, Note 23—Financial Instruments and Note 24—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 benefit obligations and the fair value 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, which are weighted to consider each plan's target 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, 2012 and 2011, pension and other postretirement benefit plan obligations represented an aggregate liability in the amount of their net underfunded status of $639 million and $640 million, respectively. In the years ended December 31, 2012, 2011 and 2010, net periodic benefit costs were $149 million, $88 million and $91 million, respectively. See Note 16—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 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.

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, including certain reclassifications to our consolidated statements of financial position, results of operations and cash flows to present our Standard Jackup and swamp barge disposal groups and our U.S. Gulf of Mexico drilling management services operations as discontinued operations (see Note 9—Discontinued Operations). Other 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 29—Subsequent Events.

Note 3—New Accounting Pronouncements

Recently Adopted Accounting Standards

Intangibles—goodwill and other—Effective January 1, 2012, we adopted the accounting standards update that amends the goodwill impairment testing requirements by giving an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads 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. The update is effective for goodwill impairment tests performed for annual and interim periods beginning after December 15, 2011. Our adoption did not have an effect on our consolidated financial statements.

Fair value measurements—Effective January 1, 2012, we adopted the accounting standards update that requires additional disclosure about fair value measurements that involve significant unobservable inputs, including additional quantitative information about the unobservable inputs, a description of valuation techniques used, and a qualitative evaluation of the sensitivity of these measurements. Our adoption did not have a material effect on the disclosures contained in our notes to consolidated financial statements.

Recently Issued Accounting Standards

Balance sheet—Effective January 1, 2013, we will adopt 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. The update is effective for interim and annual periods beginning on or after January 1, 2013. We do not expect that our adoption will have a material effect on our condensed consolidated balance sheet or the disclosures contained in our notes to consolidated financial statements.

Note 4—Correction of Errors in Previously Reported Consolidated Financial Statements

We perform assessments of our contingencies and corresponding assets for insurance recoveries on an ongoing basis to evaluate the appropriateness of our balances and disclosures for such contingencies and insurance recoveries. 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. In performing these assessments in the three months ended June 30, 2012, we identified an error in our previously issued financial statements for the year ended December 31, 2011 related to the recognition of assets for insurance recoveries related to legal and other costs totaling $67 million, which we have concluded should not have been recorded because they were not probable of recovery.

We assessed the materiality of this error in accordance with the U.S. Securities and Exchange Commission ("SEC") Staff Accounting Bulletin ("SAB") No. 99, Materiality and SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements ("SAB 108"), using both the rollover method and the iron curtain method, as defined in SAB 108, and concluded the error, inclusive of other adjustments discussed below, was immaterial to prior years but could have been material to the current year. Under SAB 108, if the prior year error that, if corrected in the current year, would be material to the current year, the prior year financial statements should be corrected, even though such correction previously was immaterial to the prior year financial statements.

In addition to the adjustments related to the assets for insurance recoveries, we recorded other adjustments related to the years ended December 31, 2011 and 2010 and the three months ended March 31, 2012 to correct for immaterial errors for repair and maintenance costs, income taxes, discontinued operations, and the allocation of net income attributable to noncontrolling interest. These other adjustments were not previously recorded in the appropriate periods, as we concluded that they were immaterial to our previously issued consolidated financial statements.

For the year ended December 31, 2011, correction of these errors increased our loss from continuing operations by $31 million and net loss attributable to controlling interest by $29 million. For the year ended December 31, 2010, correction of these errors reduced our income from continuing operations by $19 million and net income attributable to controlling interest by $35 million. We have reflected the corrections in our financial statements for each of the interim periods in the year ended December 31, 2011 as presented in Note 28—Quarterly Results.

The summary of adjustments for increases and (decreases) to net income (loss) from continuing operations and net income (loss) attributable to controlling interest for the applicable periods were as follows (in millions):

	Years ended December 31,	
	2011	2010
Legal and other costs	$ (67)	$ —
Repair and maintenance costs	11	(11)

Income tax (expense) benefit	16	(4)
Other immaterial adjustments, net	9	(4)
Net adjustment to income from continuing operations	(31)	(19)
Net adjustment to income from discontinued operations, net of tax	(14)	—
Net adjustment to net income attributable to noncontrolling interest	16	(16)
Net adjustment to net income attributable to controlling interest	$ (29)	$ (35)

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

The effects of the corrections of the errors on our consolidated statements of operations and balance sheets are presented in the tables below. Previously reported amounts have been adjusted to reflect the reclassifications associated with our discontinued operations. The corrections of the errors had no effect on our consolidated statements of comprehensive income (loss) other than the effect of the changes to net income (loss) for each period. The corrections of the errors had no effect on the previously reported amounts of operating, investing, and financing cash flows in our consolidated statements of cash flows.

	Year ended December 31, 2011			Year ended December 31, 2010		
	Previously reported	Adjustments	As adjusted	Previously reported	Adjustments	As adjusted
Operating revenues						
Contract drilling revenues	$ 7,413	$ (6)	$ 7,407	$ 7,698	$ —	$ 7,698
Other revenues	620	—	620	251	—	251
	8,033	(6)	8,027	7,949	—	7,949
Costs and expenses						
Operating and maintenance	6,134	45	6,179	4,204	15	4,219
Depreciation and amortization	1,113	(4)	1,109	1,009	—	1,009
General and administrative	288	—	288	246	—	246
	7,535	41	7,576	5,459	15	5,474
Loss on impairment	(5,201)	—	(5,201)	—	—	—
Gain (loss) on disposal of assets, net	(12)	—	(12)	255	—	255
Operating income (loss)	(4,715)	(47)	(4,762)	2,745	(15)	2,730
Other income (expense), net						
Interest income	44	—	44	23	—	23
Interest expense, net of amounts capitalized	(621)	—	(621)	(567)	—	(567)
Other, net	(99)	—	(99)	(31)	—	(31)
	(676)	—	(676)	(575)	—	(575)
Income (loss) from continuing operations before income tax expense	(5,391)	(47)	(5,438)	2,170	(15)	2,155
Income tax (benefit) expense	340	(16)	324	288	4	292
Income (loss) from continuing operations	(5,731)	(31)	(5,762)	1,882	(19)	1,863
	99	(14)	85	(894)	—	(894)

Income (loss) from discontinued operations, net of tax						
Net income (loss)	(5,632)	(45)	(5,677)	988	(19)	969
Net income (loss) attributable to noncontrolling interest	93	(16)	77	27	16	43
Net income (loss) attributable to controlling interest	$ (5,725)	$ (29)	$ (5,754)	$ 961	$ (35)	$ 926
Earnings (loss) per share-basic						
Earnings (loss) from continuing operations	$ (18.10)	$ (0.04)	$ (18.14)	$ 5.77	$ (0.11)	$ 5.66
Earnings (loss) from discontinued operations	0.31	(0.05)	0.26	(2.78)	—	(2.78)
Earnings (loss) per share	$ (17.79)	$ (0.09)	$ (17.88)	$ 2.99	$ (0.11)	$ 2.88
Earnings (loss) per share-diluted						
Earnings (loss) from continuing operations	$ (18.10)	$ (0.04)	$ (18.14)	$ 5.77	$ (0.11)	$ 5.66
Earnings (loss) from discontinued operations	0.31	(0.05)	0.26	(2.78)	—	(2.78)
Earnings (loss) per share	$ (17.79)	$ (0.09)	$ (17.88)	$ 2.99	$ (0.11)	$ 2.88

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

	December 31, 2011			December 31, 2010		
	Previously reported	Adjustments	As adjusted	Previously reported	Adjustments	As adjusted
Assets						
Cash and cash equivalents	$ 4,017	$ —	$ 4,017	$ 3,394	$ (40)	$ 3,354
Accounts receivable, net						
Trade	2,049	—	2,049	1,653	—	1,653
Other	127	—	127	190	—	190
Materials and supplies, net	529	—	529	425	—	425
Deferred income taxes, net	142	—	142	115	—	115
Assets held for sale	26	—	26	—	—	—
Other current assets	719	(73)	646	418	54	472
Total current assets	7,609	(73)	7,536	6,195	14	6,209
Property and equipment	24,833	—	24,833	22,149	—	22,149
Property and equipment of consolidated variable interest entities	2,252	—	2,252	2,214	—	2,214
Less accumulated depreciation	6,301	(4)	6,297	5,244	—	5,244
Property and equipment, net	20,784	4	20,788	19,119	—	19,119
Goodwill	3,205	12	3,217	8,132	—	8,132
Other assets	3,490	1	3,491	3,365	(11)	3,354
Total assets	$ 35,088	$ (56)	$ 35,032	$ 36,811	$ 3	$ 36,814
Liabilities and equity						
Accounts payable	$ 880	$ —	$ 880	$ 832	$ —	$ 832
Accrued income taxes	86	—	86	109	—	109
Debt due within one year	1,942	—	1,942	1,917	—	1,917
Debt of consolidated variable interest entities due within one year	97	148	245	95	148	243
Other current liabilities	2,353	22	2,375	883	12	895
	5,358	170	5,528	3,836	160	3,996

Total current liabilities						
Long-term debt	10,756	—	10,756	8,354	—	8,354
Long-term debt of consolidated variable interest entities	741	(148)	593	855	(148)	707
Deferred income taxes, net	491	(4)	487	575	10	585
Other long-term liabilities	1,935	(10)	1,925	1,791	—	1,791
Total long-term liabilities	13,923	(162)	13,761	11,575	(138)	11,437
Commitments and contingencies						
Redeemable noncontrolling interest	116	—	116	25	16	41
Shares	4,982	—	4,982	4,482	—	4,482
Additional paid-in capital	7,211	—	7,211	7,504	—	7,504
Treasury shares, at cost	(240)	—	(240)	(240)	—	(240)
Retained earnings	4,244	(64)	4,180	9,969	(35)	9,934
Accumulated other comprehensive loss	(496)	—	(496)	(332)	—	(332)
Total controlling interest shareholders' equity	15,701	(64)	15,637	21,383	(35)	21,348
Noncontrolling interest	(10)	—	(10)	(8)	—	(8)
Total equity	15,691	(64)	15,627	21,375	(35)	21,340
Total liabilities and equity	$ 35,088	$ (56)	$ 35,032	$ 36,811	$ 3	$ 36,814

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

Note 5—Business Combination

On August 14, 2011, we entered into an irrevocable agreement with Aker Capital AS to acquire its 41 percent interest in Aker Drilling. After receiving clearance by the Oslo Stock Exchange on August 26, 2011, we launched an all cash offer for 100 percent of the shares of Aker Drilling for NOK 26.50 per share.

As of October 3, 2011, the acquisition date, we held 99 percent of the shares of Aker Drilling, having paid an aggregate amount of NOK 7.9 billion, equivalent to $1.4 billion. On October 4, 2011, we acquired the remaining noncontrolling interest from holders that were required to tender their shares pursuant to Norwegian law. We believe the acquisition of Aker Drilling enhances the composition of our High-Specification Floater fleet and strengthens our presence in Norway. In accounting for the business combination, we applied the acquisition method of accounting, recording the assets and liabilities of Aker Drilling at their estimated fair values as of the acquisition date. In the year ended December 31, 2011, we incurred acquisition costs of $22 million, recognized in general and administrative expense.

As of October 3, 2011, the acquisition price included the following, measured at estimated fair value: current assets of $323 million, drilling rigs and other property and equipment of $1.8 billion, other assets of $757 million, and the assumption of long-term debt of $1.6 billion and other liabilities of $291 million. The acquired assets included $901 million of cash investments restricted for the payment of certain assumed debt instruments. The excess of the purchase price over the estimated fair value of net assets acquired was approximately $285 million, which was recorded as goodwill.

We included approximately three months of operating results of Aker Drilling in our consolidated results of operations for the year ended December 31, 2011. In the years ended December 31, 2012 and 2011, our contract drilling revenues included approximately $380 million and $100 million, respectively, of contract drilling revenues associated with the operations of Aker Drilling.

Unaudited pro forma combined operating results, assuming the acquisition was completed as of January 1, 2010, were as follows (in millions, except per share data):

	Years ended December 31,	
	2011	2010
Operating revenues	$ 8,339	$ 8,280
Operating income (loss)	(4,616)	2,848
Income (loss) from continuing operations	(5,664)	1,899
Per share earnings (loss) from continuing operations		
Basic	$ (17.84)	$ 5.77

Diluted	$ (17.84)	$ 5.77

The pro forma financial information includes various adjustments, primarily related to depreciation expense resulting from the fair value adjustments to the acquired property and equipment. The pro forma information is not necessarily indicative of the results of operations had the acquisition of Aker Drilling been completed on the assumed date or the results of operations for any future periods.

Note 6—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):

	December 31, 2012			December 31, 2011		
	Assets	Liabilities	Net carrying amount	Assets	Liabilities	Net carrying amount
Variable interest entity						
TPDI	$ —	$ —	$ —	$ 1,562	$ 673	$ 889
ADDCL	954	296	658	930	334	596
TDSOI	277	15	262	—	—	—
Total	$ 1,231	$ 311	$ 920	$ 2,492	$ 1,007	$ 1,485

Transocean Pacific Drilling Inc. (“TPDI”), a consolidated British Virgin Islands company, 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 TPDI, 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.

On May 31, 2012, TPDI became a wholly owned subsidiary and no longer met the definition of a variable interest entity. See Note 18—Redeemable Noncontrolling Interest.

At December 31, 2012 and 2011, 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 $805 million and $2.2 billion, respectively. See Note 14—Debt.

Unconsolidated variable interest entities—As holder of two notes receivable and a lender under a working capital loan, 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 a 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. Borrowings under the working capital loan, also secured by the two drilling units, had a stated interest rate of 10 percent and were payable in scheduled quarterly installments of principal and interest through maturity in January 2013, subject to acceleration under certain conditions. On a quarterly basis, we evaluate the credit quality and financial condition of Awilco with respect to our maximum exposure of loss, represented by the outstanding amounts due. At December 31, 2012 and 2011, the aggregate carrying amount of the notes receivable was $105 million and $110 million, respectively. In October 2012, Awilco repaid the remaining outstanding borrowings under the working capital loan. At December 31, 2011, the aggregate carrying amount of the working capital loan receivable was $29 million.

Note 7—Intangible Asset Impairments

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 on impairment, representing our best estimate, in the amount of $5.2 billion ($16.15 per diluted share from continuing operations), which had no tax effect. In the year ended December 31, 2012, we completed our analysis and recognized an incremental adjustment to our original estimate in the amount of $118 million ($0.33 per diluted share from continuing operations), which had no tax effect. We estimated the implied fair value of the goodwill using a variety of valuation methods, including 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 availability 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 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 availability and dayrates. 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 on impairment of $22 million ($17 million, or $0.05 per diluted share from continuing operations, net of tax) in the year ended December 31, 2012.

See Note 9—Discontinued Operations.

Note 8—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,		
	2012	2011	2010
Current tax expense	$ 183	$ 386	$ 396
Deferred tax benefit	(133)	(62)	(104)
Income tax expense	$ 50	$ 324	$ 292

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,		
	2012	2011	2010
Income tax expense at the Swiss federal statutory rate	$ 68	$ (426)	$ 168
Taxes on earnings subject to rates different than the Swiss federal statutory rate	141	221	72
Taxes on impairment loss subject to rates different than the Swiss federal statutory rate	5	409	—
Taxes on asset sales subject to rates different than the Swiss federal statutory rate	(1)	—	—
Taxes on litigation matters subject to rates different than the Swiss federal statutory rate	59	78	—
Changes in unrecognized tax benefits, net	(179)	40	73
Change in valuation allowance	1	19	4
Benefit from foreign tax credits	(38)	(28)	(23)
Taxes on asset acquisition costs at rates lower than the Swiss federal statutory rate	—	8	—
Other, net	(6)	3	(2)
Income tax expense	$ 50	$ 324	$ 292

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

	December 31, 2012	December 31, 2011
Deferred tax assets		
Drilling contract intangibles	$ 1	$ 2
Net operating loss carryforwards	380	331
Tax credit carryforwards	41	45
Accrued payroll expenses not currently deductible	95	79
Deferred income	86	65
Valuation allowance	(210)	(183)
Other	108	104
Total deferred tax assets	501	443
Deferred tax liabilities		
Depreciation and amortization	(688)	(746)
Drilling management services intangibles	—	—
Other	(37)	(42)
Total deferred tax liabilities	(725)	(788)
Net deferred tax liabilities	$ (224)	$ (345)

Our deferred tax assets include U.S. foreign tax credit carryforwards of $41 million, which will expire between 2015 and 2021. Deferred tax assets related to our net operating losses were generated in various worldwide tax jurisdictions. At December 31, 2012 and 2011, the tax effect of our Brazilian net operating losses, which do not expire, was $55 million and $57 million, respectively. In connection with our acquisition of Aker Drilling, we acquired $141 million of Norwegian net operating losses, which do not expire.

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

	December 31, 2012	December 31, 2011
Valuation allowance for non-current deferred tax assets	$ 210	$ 183

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, 2012, 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 $230 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,		
	2012	2011	2010
Balance, beginning of period	$ 515	$ 485	$ 460
Additions for current year tax positions	58	45	46
Additions for prior year tax positions	25	29	9
Reductions for prior year tax positions	(24)	—	(11)
Settlements	(120)	(42)	(17)
Reductions related to statute of limitation expirations	(72)	(2)	(2)
Balance, end of period	$ 382	$ 515	$ 485

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

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,	
	2012	2011
Unrecognized tax benefits, excluding interest and penalties	$ 382	$ 515
Interest and penalties	199	256
Unrecognized tax benefits, including interest and penalties	$ 581	$ 771

In the years ended December 31, 2012, 2011 and 2010, we recognized interest and penalties related to our unrecognized tax benefits, recorded as a component of income tax expense, in the amount of $56 million, $20 million and $35 million, respectively. If recognized, $581 million of our unrecognized tax benefits, including interest and penalties, as of December 31, 2012, 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, 2013 primarily due to the progression of open audits or 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 the U.S., Norway and Brazil, which are mentioned below, are generally subject to examination for periods ranging from three to six years. We have agreed to extensions beyond the statute of limitations in two major jurisdictions for up to 18 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 cash flows.

U.S. tax investigations—With respect to our 2004 U.S. federal income tax return, the U.S. tax authorities withdrew all of their previously proposed tax adjustments, including all claims related to transfer pricing. In January 2012, a judge in the U.S. Tax Court entered a decision of no deficiency for the 2004 tax year and cancelled the trial previously scheduled to take place in February 2012. With respect to our 2005 U.S. federal income tax returns, the U.S. tax authorities have withdrawn all of their previously proposed tax adjustments. Our 2004 and 2005 U.S. federal income tax returns are now settled and the tax years are now closed.

With respect to our 2006 and 2007 federal income tax returns, we reached an agreement with the U.S. tax authorities in December 2012, to settle all issues, including transfer pricing for certain charters of drilling rigs between our subsidiaries and the creation of intangible assets resulting from the performance of engineering services between our subsidiaries for $11 million of additional tax, excluding interest and penalties, and the tax years are now closed.

In February 2012, we received an assessment from the U.S. tax authorities related to our 2008 and 2009 U.S. federal income tax returns. The significant issues raised in the assessment relate to transfer pricing for certain charters of drilling rigs between our subsidiaries and the creation of intangible assets resulting from the performance of engineering services between our subsidiaries. With respect to transfer pricing issues related to certain charters of drilling rigs in 2008 and 2009, we reached an agreement with the U.S. tax authorities in December 2012, to settle this issue and other issues raised during the audit for $36 million, excluding interest and penalties. The only remaining issue outstanding for these years relates to an asserted creation of intangible assets resulting from the performance of engineering services between our subsidiaries for which a royalty is asserted. The initial assessment issued by the tax authorities on this item, if sustained, would result in net adjustments of approximately $363 million of additional taxes, excluding interest and penalties. An unfavorable outcome on this adjustment 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 this position with respect to subsequent years and were successful in such assertion, our effective tax rate on worldwide earnings with respect to years following 2009 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.

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 of approximately $123 million, plus interest, related to the migration of a subsidiary that was previously subject to tax in Norway, approximately $74 million, plus interest, related to a 2001 dividend payment, and approximately $8 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 $125 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 $218 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 approximately $123 million related to the migration of our subsidiary. We believe that our Norwegian tax returns are materially correct as filed and if we receive unfavorable outcome at the district court, we expect to appeal the decision. In addition, we expect to file or have filed appeals to the two other tax assessments.

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 indictments with respect to the disclosures in our tax returns. In October 2011, the Norwegian authorities issued criminal indictments against a Norwegian tax attorney related to certain of our restructuring transactions and to the 2001 dividend payment. The indicted Norwegian tax attorney worked for us in an advisory capacity on these transactions. 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 approximately $330 million, jointly and severally, against our two subsidiaries, the two external advisors and the external tax attorney. In February 2012, the authorities dropped the previously existing tax assessment 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 on the same matter, alleging misleading or incomplete disclosures in Norwegian tax returns for the years 2001 and 2002. 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. See Note 29–Subsequent Events.

Brazil tax investigations—Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. The Brazilian tax authorities have issued tax assessments totaling $98 million, plus a 75 percent penalty in the amount of $73 million and interest through December 31, 2011 in the amount of $147 million. We believe our returns are materially correct as filed, and we are vigorously contesting these assessments. On January 25, 2008, we filed a protest letter with the Brazilian tax authorities, and we are currently engaged in the appeals process. 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.

Note 9—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,		
	2012	2011	2010
Operating revenues	$ 1,055	$ 1,171	$ 1,627
Operating and maintenance expense	(990)	(871)	(916)
Depreciation and amortization expense	(183)	(342)	(580)
Loss on impairment of assets in discontinued operations, net	(986)	(38)	(1,012)
Gain on disposal of discontinued operations, net	82	183	2
Other income, net	—	18	8
Income (loss) from discontinued operations before income tax expense	(1,022)	121	(871)
Income tax expense	(5)	(36)	(23)
Income (loss) from discontinued operations, net of tax	$ (1,027)	$ 85	$ (894)

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,	
	2012	2011
Assets		
Rigs and related equipment, net	$ 104	$ —
Materials and supplies	71	—
Oil and gas properties, net	—	24

Other related assets	4	2
Assets held for sale	$ 179	$ 26
Materials and supplies	$ —	$ 98
Other assets	—	21
Other current assets	$ —	$ 119
Rig and related equipment, net	$ —	$ 1,745
Intangible assets	—	70
Deferred costs	—	42
Other assets	$ —	$ 1,857
Liabilities		
Deferred revenues	$ 32	$ 17
Deferred income taxes, net	—	6
Other liabilities	3	14
Other current liabilities	$ 35	$ 37
Deferred revenues	$ —	$ 8
Deferred taxes, net	—	32
Other long-term liabilities	$ —	$ 40

Standard Jackup and swamp barge contract drilling operations

Overview—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 estimated the fair value of the disposal group and the contract drilling services operating segment using a variety of valuation methods, including the income and market approaches. 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 disposal group and of our contract drilling services reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates.

At December 31, 2012, the remaining Standard Jackups, which were not sold in the sale transactions with Shelf Drilling, including D.R. Stewart, GSF Adriatic VIII, GSF Rig 127, GSF Rig 134, Interocean III, Trident IV-A and Trident VI, and related equipment, were classified as held for sale with an aggregate carrying amount of $112 million, including $8 million in materials and supplies.

Impairments—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, including 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, 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 disposal group, such as long-term projections for future revenues and costs, dayrates, rig utilization and idle time. We measured the impairments of the disposal group as the amount by which the carrying amounts exceeded its estimated fair value less costs to sell. Included in the loss on impairment, we recognized $20 million of personnel costs relating to postemployment obligations for certain employees and contract labor. The loss on impairment also included approximately $60 million of costs for the required reactivation of one drilling unit 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 ($2.08 per diluted share) and $112 million ($0.31 per diluted share), with no tax effect, associated with the impairment of long-lived assets and the goodwill, respectively.

In the year ended December 31, 2012, we also recognized aggregate losses 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, which were classified as assets held for sale at the time of impairment. In the year ended December 31, 2011, we recognized aggregate losses 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, 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 value of the assets using significant other observable inputs, representative of Level 2 fair value measurements, including binding sale and purchase agreements for the drilling units and related equipment.

During the year ended December 31, 2010, we determined that the Standard Jackup asset group in our contract drilling services reporting unit was impaired due to projected declines in dayrates and utilization rates. We measured the fair value of this asset group by applying a combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date. We estimated the fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of the asset group, such as long-term projections for future revenues and costs, dayrates, rig utilization rates and idle time. As a result, we determined that the carrying amount of the Standard Jackup asset group exceeded its fair value, and in the year ended December 31, 2010, we recognized a loss on impairment of long-lived assets in the amount of $1.0 billion ($3.13 per diluted share), which had no tax effect.

Sale transactions with Shelf Drilling—On November 30, 2012, we completed the sale of 38 drilling units to Shelf Drilling. Such drilling units included the Standard Jackup GSF Baltic, which was formerly classified as a High-Specification Jackup, the Standard Jackups C.E. Thornton, F.G. McClintock, GSF Adriatic I, GSF Adriatic V, GSF Adriatic VI, GSF Adriatic IX, GSF Adriatic X, GSF Compact Driller, GSF Galveston Key, GSF High Island II, GSF High Island IV, GSF High Island V, GSF High Island VII, GSF High Island IX, GSF Key Gibraltar, GSF Key Hawaii, GSF Key Manhattan, GSF Key Singapore, GSF Main Pass I, GSF Main Pass IV, GSF Parameswara, GSF Rig 105, GSF Rig 124, GSF Rig 141, Harvey H. Ward, J.T. Angel, Randolph Yost, Ron Tappmeyer, Transocean Comet, Trident II, Trident VIII, Trident IX, Trident XII, Trident XIV, Trident XV and Trident XVI and the swamp barge Hibiscus, along with related equipment.

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 $196 million and an estimated fair value of $194 million, including the fair value associated with embedded derivatives, at the closing of the transaction. Although we based certain components of our valuation of the preference shares on significant other observable inputs, such as market dividend rates and projected oil prices, we estimated fair value using significant unobservable inputs, representative of a Level 3 fair value measurement, including the credit ratings and financial position of the investee. As a result of the sale transactions with Shelf Drilling, in the year ended December 31, 2012, we recognized a gain on the disposal of the assets sold in the amount of $8 million (net loss of $5 million or $0.01 per diluted share, net of tax), subject to working capital and other adjustments currently under review by us and Shelf Drilling pursuant to the terms of the sales agreements. Such adjustments, if not resolved between us and Shelf Drilling within the period of time stipulated in the agreements will become subject to a dispute resolution process. While we cannot provide assurance as to the final resolution of the adjustments, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

The ultimate parent company of Shelf Drilling is a newly formed company sponsored equally by three private equity firms. The preference shares received in the sale transactions represent an interest in an intermediate parent company of Shelf Drilling. As holder of the preference shares, we are entitled to cumulative dividends, payable in-kind, at 10 percent per annum, escalating two percent biannually to a maximum of 14 percent but subject to reductions or increases under certain circumstances. The preference shares contain two embedded derivatives, including (a) a ceiling dividend rate indexed to the price of Brent Crude oil and (b) a dividend rate premium triggered in the event of credit default (see Note 15—Derivatives and Hedging). The preference shares are subject to mandatory redemption upon certain specified events outside of our control, including an initial public offering or change of control of 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 under operating agreements with Shelf Drilling and to provide certain other transition services to Shelf Drilling. The costs to us of providing such operating and transition services may exceed the amounts we receive from Shelf Drilling as compensation 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. As of December 31, 2012, we operated 25 Standard Jackups under operating agreements with 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.

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, 2012, we had $113 million of outstanding letters of credit, issued under our committed and uncommitted credit lines, in support of drilling units sold to Shelf Drilling. See Note 17—Commitments and Contingencies.

Other dispositions—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. 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 years ended December 31, 2012 and 2011, we received aggregate net cash proceeds of $201 million and $185 million, and we recognized an aggregate net gain on disposal of these assets in the amount of $74 million ($0.20 per diluted share) and $32 million ($0.10 per diluted share), respectively, which had no tax effect in either period. In the years ended December 31, 2012 and 2011, we recognized losses on the disposal of unrelated assets in the amount of $9 million and $1 million, respectively.

In December 2012, we entered into agreements to sell the Standard Jackups D.R. Stewart and GSF Adriatic VIII and related equipment. See Note 29—Subsequent Events.

Caspian Sea contract drilling operations

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 gain on the disposal of the assets 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 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 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 increased 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 availability and dayrates. 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 on impairment of $31 million ($20 million or $0.06 per diluted share, net of tax) in the year ended December 31, 2012.

During the year ended December 31, 2012, we determined that the trade name intangible asset associated with 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 increased regulatory environment for obtaining drilling permits and the diminishing demand for drilling management services. 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 availability and dayrates. As a result of our valuation, we determined that the carrying amount of the trade name intangible asset exceeded its fair value, and we recognized a loss on impairment of $39 million ($25 million or $0.07 per diluted share, net of tax) in the year ended December 31, 2012.

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.

Impairments—In the year ended December 31, 2012, we recognized losses of $11 million ($10 million or $0.02 per diluted share, net of tax) associated with the impairment of our oil and gas properties, which were classified as assets held for sale, since the carrying amount of the properties exceeded the estimated fair value less costs to sell the properties. In the year ended December 31, 2011, we recognized a loss of $10 million ($6 million or $0.02 per diluted share, net of tax) associated with the impairment of our oil and gas properties, which were classified as assets held for sale, since the carrying amount of the properties exceeded the estimated fair value less costs to sell the properties. We estimated fair value based on significant other observable inputs, representative of a Level 2 fair value measurement, including a binding sale and purchase agreement for the properties.

Dispositions—In October 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. 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 $7 million and $6 million, respectively. In the year ended December 31, 2012, in connection with these disposals, we recognized an aggregate net gain of $9 million ($0.02 per diluted share), which had no tax effect. In the year ended December 31, 2011, in connection with these disposals, we recognized an aggregate net loss of $4 million (aggregate net gain of $14 million or $0.05, net of tax).

Note 10—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,					
	2012		2011		2010	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
Numerator for earnings (loss) per share						
Income (loss) from continuing operations attributable to controlling interest	$ 808	$ 808	$ (5,839)	$ (5,839)	$ 1,820	$ 1,820
Undistributed earnings allocable to participating securities	—	—	—	—	(10)	(10)
Income (loss) from continuing operations available to shareholders	$ 808	$ 808	$ (5,839)	$ (5,839)	$ 1,810	$ 1,810
Denominator for earnings (loss) per share						
Weighted-average shares outstanding	356	356	322	322	320	320
Effect of stock options and other share-based awards	—	—	—	—	—	—
Weighted-average shares for per share calculation	356	356	322	322	320	320
Per share earnings (loss) from continuing operations	$ 2.27	$ 2.27	$ (18.14)	$ (18.14)	$ 5.66	$ 5.66

For the years ended December 31, 2012, 2011 and 2010, respectively, we have excluded 2.4 million, 2.4 million and 2.2 million share-based awards from the calculation since the effect would have been anti-dilutive. The 1.625% Series A Convertible Senior Notes, 1.50% Series B Convertible Senior Notes and 1.50% Series C Convertible Senior Notes did not have an effect on the calculation for the periods presented. See Note 14—Debt.

Note 11—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,								
	2012			2011			2010		
	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	T
cognized ponents of eriodic fit costs	$ (52)	$ —	$ (52)	$ (204)	$ —	$ (204)	$ (8)	$ —	$
cognized (loss) on rative uments	6	(3)	3	3	(16)	(13)	(10)	(19)	
cognized on etable rities	—	—	—	(13)	—	(13)	—	—	
gnized ponents of eriodic fit costs	47	—	47	25	—	25	16	—	
gnized) loss on rative uments	(4)	3	(1)	(1)	12	11	14	(2)	
gnized on etable rities	2	—	2	13	—	13	—	—	
r prehensive me (loss) re income	(1)	—	(1)	(177)	(4)	(181)	12	(21)	
me taxes ed to other prehensive me (loss)	(7)	—	(7)	13	—	13	(9)	—	
r prehensive me (loss), f tax	$ (8)	$ —	$ (8)	$ (164)	$ (4)	$ (168)	$ 3	$ (21)	$

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

Note 12—Drilling Fleet

Construction work in progress—Capital expenditures and other capital additions, including capitalized interest, for each of the three years ended December 31, 2012 were as follows (in millions):

	Years ended December 31,		
	2012	2011	2010
Construction work in progress, at beginning of period	$ 1,360	$ 1,450	$ 3,657
Newbuild construction program			
Ultra-Deepwater Floater TBN1 (a)	139	—	—
Ultra-Deepwater Floater TBN2 (a)	128	—	—
Ultra-Deepwater Floater TBN3 (a)	76	—	—
Ultra-Deepwater Floater TBN4 (a)	76	—	—
Transocean Ao Thai (b)	72	80	—
Deepwater Asgard (c)	46	4	—
Deepwater Invictus (c)	40	3	—
Transocean Siam Driller (b)	39	113	9
Transocean Andaman (b)	38	113	9
Transocean Honor (d)	35	129	98
Deepwater Champion (e)	—	76	249
Discoverer India (f)	—	—	262
Discoverer Luanda (g)	—	—	212
Dhirubhai Deepwater KG2 (h)	—	—	45
Discoverer Inspiration (h)	—	—	33
Other construction projects and capital additions	614	456	432
Total capital expenditures	1,303	974	1,349
Acquisition of construction work in progress (c)	—	272	—
Changes in accrued capital expenditures	61	(2)	(57)
Property and equipment placed into service			
Transocean Honor (d)	(262)	—	—
Deepwater Champion (e)	—	(881)	—
Discoverer India (f)	—	—	(835)
Discoverer Luanda (g)	—	—	(783)
Discoverer Inspiration (h)	—	—	(781)
Dhirubhai Deepwater KG2 (h)	—	—	(707)
Other property and equipment	(490)	(453)	(393)
Construction work in progress, at end of period	$ 1,972	$ 1,360	$ 1,450

(a) Our 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 fourth quarter of 2015, the second quarter of 2016, the fourth quarter of 2016 and the first quarter of 2017.

(b) Transocean Siam Driller, Transocean Andaman and Transocean Ao Thai, three Keppel FELS Super B class design High-Specification Jackups, under construction at Keppel FELS' yard in Singapore, are expected to commence operations in the first quarter of 2013, the second quarter of 2013 and the fourth quarter of 2013, respectively.

(c) Deepwater Asgard and Deepwater Invictus, two Ultra-Deepwater drillships under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, are expected to be ready to commence operations in the second quarter of 2014. In the year ended December 31, 2011, we acquired the construction work in progress associated with these Ultra-Deepwater drillships with an aggregate estimated fair value of $272 million. See Note 5—Business Combination.

(d) Transocean Honor, a PPL Pacific Class 400 design High-Specification Jackup, 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.

(e) Deepwater Champion, an Ultra-Deepwater drillship, commenced operations in May 2011.

(f) Discoverer India, an Ultra-Deepwater drillship, commenced operations in December 2010.

(g) Discover Luanda, an Ultra-Deepwater drillship, owned through our 65 percent interest in ADDCL, commenced operations in December 2010. The costs presented above represent 100 percent of ADDCL's expenditures in the construction of Discover Luanda.

(h) Discoverer Inspiration and Dhirubhai Deepwater KG2, two Ultra-Deepwater drillships, commenced operations in March 2010.

Other capital additions—In March 2010, we acquired GSF Explorer, an asset formerly held under capital lease, in exchange for a cash payment in the amount of $15 million, thereby terminating the capital lease obligation. See Note 14—Debt.

Dispositions—During the year ended December 31, 2012, we completed the sales of the Deepwater Floaters Discoverer 534 and Jim Cunningham. In connection with the sales, we received aggregate net cash proceeds of $178 million, and we recognized a net gain on disposal of these drilling units and related equipment in the amount of $51 million ($48 million or $0.13 per diluted share from continuing operations net of tax). In the year ended December 31, 2012, we recognized a net loss on disposal of unrelated assets in the amount of $15 million.

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

During the year ended December 31, 2010, we completed the sale of two Midwater Floaters, GSF Arctic II and GSF Arctic IV. In connection with the sale, we received net cash proceeds of $38 million and non-cash proceeds in the form of two notes receivable in the aggregate amount of $165 million (see Note 6—Variable Interest Entities). We operated GSF Arctic IV under a short-term bareboat charter with the new owner of the vessel until November 2010. As a result of the sales, we recognized a net loss on disposal of assets of $15 million ($0.05 per diluted share from continuing operations), which had no tax effect in the year ended December 31, 2010. In the year ended December 31, 2010, we recognized a net gain on disposal of unrelated assets of $5 million.

Loss of drilling unit—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. In the year ended December 31, 2010, we received $560 million in cash proceeds from insurance recoveries related to the loss of the drilling unit, and we recognized a gain on the loss of the rig of $267 million ($0.83 per diluted share from continuing operations), which had no tax effect. See Note 17—Commitments and Contingencies.

Note 13—Goodwill and Other Intangible Assets

Goodwill and other indefinite-lived intangible assets—The gross carrying amounts of goodwill and accumulated impairment associated with our contract drilling services were as follows (in millions):

Year ended December 31, 2012			Year ended December 31, 2011		
Gross carrying amount	Accumulated impairment	Net carrying amount	Gross carrying amount	Accumulated impairment	Net carrying amount
$ 10,911	$ (7,694)	$ 3,217	$ 10,626	$ (2,494)	$ 8,132

Balance, beginning of period						
Impairment associated with continuing operations	—	(118)	(118)	—	(5,200)	(5,200)
Reclassified balance associated with discontinued operations (a)	(112)	—	(112)	—	—	—
Business combination	—	—	—	285	—	285
Balance, end of period	$ 10,799	$ (7,812)	$ 2,987	$ 10,911	$ (7,694)	$ 3,217

(a) As a result of our decision to discontinue operations associated with the Standard Jackups and swamp barge components of our contract drilling services operating segment, we allocated $112 million of goodwill attributable to such operations, which was subsequently impaired. See Note 9—Discontinued Operations.

At December 31, 2012 and 2011, goodwill associated with our drilling management services, having a gross carrying amount of $176 million, was fully impaired.

The gross carrying amounts of the ADTI trade name, which we considered to be an indefinite-lived intangible asset attributed to the U.S. operations of our drilling management services segment, and accumulated impairment were as follows (in millions):

	Year ended December 31, 2012			Year ended December 31, 2011		
	Gross carrying amount	Accumulated impairment	Net carrying amount	Gross carrying amount	Accumulated impairment	Net carrying amount
Trade name						
Balance, beginning of period	$ 76	$ (37)	$ 39	$ 76	$ (37)	$ 39
Reclassified balance associated with discontinued operations (a)	(76)	37	(39)	—	—	—
Balance, end of period	$ —	$ —	$ —	$ 76	$ (37)	$ 39

(a) 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 9—Discontinued Operations.

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, 2012			Year ended December 31, 2011		
	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	$ 191	$ (191)	$ —	$ 191	$ (185)	$ 6
Amortization	—	—	—	—	(6)	(6)
Reclassified balance associated with discontinued operations (a)	(182)	182	—	—	—	—
Balance, end of period	9	9	—	191	(191)	—
Customer relationships						
Balance, beginning of period	148	(94)	54	148	(89)	59
Amortization	—	(1)	(1)	—	(5)	(5)
Impairment associated with continuing operations	—	(22)	(22)	—	—	—
Reclassified balance associated with discontinued operations (b)	(88)	57	(31)	—	—	—
Balance, end of period	60	(60)	—	148	(94)	54
Total definite-lived intangible assets						
Balance, beginning of period	339	(285)	54	339	(274)	65
Amortization	—	(1)	(1)	—	(11)	(11)
Impairment associated with continuing operations	—	(22)	(22)	—	—	—
Reclassified balance associated with	(270)	239	(31)	—	—	—

discontinued operations (b)						
Balance, end of period	$ 69	$ (69)	$ —	$ 339	$ (285)	$ 54
Drilling contract intangible liabilities						
Balance, beginning of period	$ 1,494	$ (1,393)	$ 101	$ 1,494	$ (1,342)	$ 152
Amortization	—	(42)	(42)	—	(51)	(51)
Reclassified balance associated with discontinued operations (a)	(84)	84	—	—	—	—
Balance, end of period	$ 1,410	$ (1,351)	$ 59	$ 1,494	$ (1,393)	$ 101

(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 9—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 9—Discontinued Operations.

At December 31, 2012, the estimated future amortization of our drilling contract intangible liabilities was as follows (in millions):

	Drilling contract intangible liabilities
Years ending December 31,	
2013	$ 24
2014	15
2015	14
2016	6
Total intangible liabilities	$ 59

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

Note 14—Debt

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

	December 31, 2012			December 31, 2011		
	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	$ 253	$ —	$ 253
5.25% Senior Notes due March 2013 (a)	502	—	502	507	—	507
TPDI Credit Facilities due March 2015	403	—	403	—	473	473
4.95% Senior Notes due November 2015 (a)	1,118	—	1,118	1,120	—	1,120
Aker Revolving Credit and Term Loan Facility due December 2015	—	—	—	594	—	594
Callable Bonds due February 2016	282	—	282	267	—	267
5.05% Senior Notes due December 2016 (a)	999	—	999	999	—	999
2.5% Senior Notes due October 2017 (a)	748	—	748	—	—	—
ADDCL Credit Facilities due December 2017	—	191	191	—	217	217
Eksportfinans Loans due January 2018	797	—	797	884	—	884
6.00% Senior Notes due March 2018 (a)	998	—	998	998	—	998
7.375% Senior Notes due April 2018 (a)	247	—	247	247	—	247
TPDI Notes due October 2019	—	—	—	—	148	148
6.50% Senior Notes due November 2020 (a)	899	—	899	899	—	899
	1,199	—	1,199	1,199	—	1,199

6.375% Senior Notes due December 2021 (a)						
3.8% Senior Notes due October 2022 (a)	745	—	745	—	—	—
7.45% Notes due April 2027 (a)	97	—	97	97	—	97
8% Debentures due April 2027 (a)	57	—	57	57	—	57
7% Notes due June 2028	311	—	311	311	—	311
Capital lease contract due August 2029	657	—	657	676	—	676
7.5% Notes due April 2031 (a)	598	—	598	598	—	598
1.50% Series B Convertible Senior Notes due December 2037 (a)	—	—	—	30	—	30
1.50% Series C Convertible Senior Notes due December 2037 (a)	62	—	62	1,663	—	1,663
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	12,268	191	12,459	12,698	838	13,536
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	—	70	70
Aker Revolving Credit and Term Loan Facility due December 2015	—	—	—	90	—	90
Callable Bonds due February 2016	282	—	282	—	—	—
ADDCL Credit Facilities due December 2017	—	28	28	—	27	27
Eksportfinans Loans due January 2018	153	—	153	142	—	142
TPDI Notes due October 2019	—	—	—	—	148	148
	20	—	20	17	—	17

Capital lease contract due August 2029						
1.50% Series B Convertible Senior Notes due December 2037 (a)	—	—	—	30	—	30
1.50% Series C Convertible Senior Notes due December 2037 (a)	62	—	62	1,663	—	1,663
Total debt due within one year	1,339	28	1,367	1,942	245	2,187
Total long-term debt	$ 10,929	$ 163	$ 11,092	$10,756	$ 593	$ 11,349

(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 26—Condensed Consolidating Financial Information.

Scheduled maturities—At December 31, 2012, 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,			
2013	$ 1,053	$ 28	$ 1,081
2014	244	30	274
2015	1,539	61	1,600
2016	1,448	35	1,483
2017	930	37	967
Thereafter	7,032	—	7,032
Total debt, excluding unamortized discounts, premiums and fair value adjustments	12,246	191	12,437
Total unamortized discounts, premiums and fair value adjustments	22	—	22
Total debt	$ 12,268	$ 191	$ 12,459

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, 2012, 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, 2012. 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, 2012, we had $24 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, 2012, 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, 2012. 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, 2012, 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, 2012 and 2011, the aggregate carrying amount of Deepwater Champion, Discoverer Americas and Discoverer Inspiration was $2.3 billion.

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. At December 31, 2012, the aggregate outstanding principal amount of the 5% Notes and the 7% Notes was $250 million and $300 million, respectively. See Note 15—Derivatives and Hedging and Note 29—Subsequent Events.

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. At December 31, 2012, the aggregate outstanding principal amount of the 5.25% Senior Notes, the 6.00% Senior Notes and the 6.80% Senior Notes was $500 million, $1.0 billion and $1.0 billion, respectively, were outstanding. See Note 15—Derivatives and Hedging.

TPDI Credit Facilities—We have 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 is scheduled to expire in March 2015 (the “TPDI Credit Facilities”). One of our subsidiaries participates in the senior and junior term loans with an aggregate commitment of $595 million. The senior term loan, the junior term loan and the revolving credit facility bear interest at LIBOR plus the applicable margins of 1.45 percent, 2.25 percent and 1.45 percent, respectively. The senior term loan requires quarterly payments with a final payment in March 2015. The junior term loan and the revolving credit facility are due in full in March 2015. The TPDI Credit Facilities have covenants that require TPDI to maintain a minimum cash balance and available liquidity, a minimum debt service ratio and a maximum leverage ratio. The TPDI Credit Facilities may be prepaid in whole or in part without premium or penalty. At December 31, 2012, outstanding borrowings under the TPDI Credit Facilities were $805 million, of which $402 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on December 31, 2012 was 1.9 percent. See Note 15—Derivatives and Hedging.

Borrowings under the TPDI Credit Facilities are secured by the Ultra-Deepwater Floaters Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2. At December 31, 2012 and 2011, the aggregate carrying amount of Dhirubhai Deepwater KG1 and Dhirubhai Deepwater KG2 was $1.4 billion.

Under the TPDI Credit Facilities, we are 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 and 2011, we had restricted cash investments of $23 million. At December 31, 2012 and 2011, we had an outstanding letter of credit in the amount of $60 million to satisfy additional liquidity requirements under the TPDI Credit Facilities.

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, 2012, 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. See Note 15—Derivatives and Hedging.

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, 2012, 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 under the Aker Term Loan, and we recognized an aggregate gain of $2 million on the retirement of debt. In September 2012, we cancelled the Aker Revolving Credit and Term Loan Facility.

Callable Bonds—In connection with our acquisition of Aker Drilling, we assumed NOK 940 million aggregate principal amount of the FRN Aker Drilling ASA Senior Unsecured Callable Bond Issue 2011/2016 (the “FRN Callable Bonds”) and NOK 560 million aggregate principal amount of 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 are publicly traded on the Oslo Stock Exchange. The FRN Callable Bonds bear interest at the Norwegian Interbank Offered Rate plus seven percent. The Callable Bonds require quarterly interest payments and may be redeemed in whole or in part at an amount equal to the outstanding principal plus a certain premium amount and accrued unpaid interest. At December 31, 2012, the total aggregate principal amounts of the FRN Callable Bonds and the 11% Callable Bonds were NOK 940 million and NOK 560 million, equivalent to $169 million and $101 million, respectively, using an exchange rate of NOK 5.56 to US $1.00. At December 31, 2012, the interest rate on the FRN Callable Bonds was 9.0 percent. See Note 15—Derivatives and Hedging and Note 29—Subsequent Events.

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, 2012, the aggregate outstanding principal amount of the 2.5% Senior Notes and the 3.8% Senior Notes was $750 million and $750 million, respectively.

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 covenants that require ADDCL to maintain certain cash balances to service the debt and also limits ADDCL’s ability to incur additional indebtedness, to acquire assets, or to make distributions or other payments. At December 31, 2012, $163 million was outstanding under Tranche A at a weighted-average interest rate of 1.2 percent. At December 31, 2012, $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, 2012 and 2011, the carrying amount of Discoverer Luanda was $786 million and $796 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, 2012, $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, 2012 was 3.4 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, 2012 and 2011, ADDCL had restricted cash investments of $19 million and $16 million, respectively.

Eksportfinans Loans—In connection with our acquisition of Aker Drilling, we assumed the 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, 2012, $381 million and $420 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 "Aker Restricted Cash Investments"). The Aker 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, 2012 and 2011, the aggregate principal amount of the Aker Restricted Cash Investments was $801 million and $889 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, 2012, the aggregate outstanding principal amount of the 7.375% Senior Notes was $246 million.

TPDI Notes—We previously issued promissory notes (the "TPDI Notes"), which were payable to one of our subsidiaries and TPDI's former other shareholder, Quantum Pacific Management Limited ("Quantum"), and had maturities through October 2019. On May 31, 2012, in connection with the exchange of Quantum's interest in TPDI for our shares, the TPDI Notes payable to Quantum were extinguished and contributed as additional paid-in capital. See Note 18—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, 2012, 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 12—Drilling Fleet and Note 17—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, 2012, the aggregate outstanding principal amount of the 7.5% Notes was $600 million.

1.625% Series A, 1.50% Series B and 1.50% Series C Convertible Senior Notes—In December 2007, we issued $2.2 billion aggregate principal amount of 1.625% Series A Convertible Senior Notes due December 2037 (the "Series A Convertible Senior Notes"), $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 A Convertible Senior Notes and Series B Convertible Senior Notes, the "Convertible Senior Notes"). At December 31, 2012, the Series C Convertible Senior Notes could be converted under the circumstances specified below at a rate of 6.2905 shares per $1,000 note, equivalent to a conversion price of $158.97 per share, subject to adjustments upon the occurrence of certain events. Upon conversion, we were required to deliver, in lieu of shares, cash up to the aggregate principal amount of notes to be converted and shares in respect of the remainder, if any, of our conversion obligation.

Holders could convert their notes only under the following circumstances: (1) during any calendar quarter if the last reported sale price of our shares for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the preceding calendar quarter is more than 130 percent of the conversion price, (2) during the five business days after the average trading price per $1,000 principal amount of the notes is equal to or less than 98 percent of the average conversion value of such notes during the preceding five trading-day period as described herein, (3) during specified periods if specified distributions to holders of our shares are made or specified corporate transactions occur, (4) prior to the close of business on the business day preceding the redemption date if the notes are called for redemption or (5) on or after September 15, 2037 and prior to the close of business on the business day prior to the stated maturity of the notes. As of December 31, 2012, no shares were issuable upon conversion of any series of the Convertible Senior Notes since none of the circumstances giving rise to potential conversion were present.

We could redeem some or all of the Series C Convertible Senior Notes at any time after December 20, 2012 at a redemption price equal to 100 percent of the principal amount plus accrued and unpaid interest, if any. Holders of the Series C Convertible Senior Notes had the right to require us to repurchase their notes on December 15, 2017, December 15, 2022, December 15, 2027 and December 15, 2032, and upon the occurrence of a fundamental change, at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any.

The carrying amounts of the liability components of the outstanding Convertible Senior Notes were as follows (in millions):

	December 31, 2012			December 31, 2011		
	Principal amount	Unamortized discount	Carrying amount	Principal amount	Unamortized discount	Carrying amount
Carrying amount of liability component						
Series B Convertible Senior Notes due 2037	$ —	$ —	$ —	$ 30	$ —	$ 30
Series C Convertible Senior Notes due 2037	62	—	62	1,722	(59)	1,663

The carrying amounts of the equity components of the outstanding Convertible Senior Notes were as follows (in millions):

	December 31,	
	2012	2011
Carrying amount of equity component		
Series B Convertible Senior Notes due 2037	$ —	$ 4
Series C Convertible Senior Notes due 2037	10	276

Including the amortization of the unamortized discount, the effective interest rate for the Series C Convertible Senior Notes was 5.28 percent. At December 31, 2012, the remaining period over which the discount will be amortized is less than one year for the Series C Convertible Senior Notes. Interest expense, excluding amortization of debt issue costs, was as follows (in millions):

	Years ended December 31,		
	2012	2011	2010
Interest expense			
Series A Convertible Senior Notes due 2037	$ —	$ —	$ 58
Series B Convertible Senior Notes due 2037	—	78	98
Series C Convertible Senior Notes due 2037	84	84	98

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. See Note 29—Subsequent Events.

On December 15, 2011, holders of the Series B 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 B Convertible Senior Notes for an aggregate cash payment of $1.7 billion. In February 2012, we redeemed the remaining $30 million aggregate principal amount of the Series B Convertible Senior Notes for an aggregate cash payment of $30 million.

On December 15, 2010, holders of the Series A 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 $1.3 billion of the Series A Convertible Senior Notes for an aggregate cash payment of $1.3 billion. In January 2011, we redeemed the remaining $11 million aggregate principal amount of the Series A Convertible Senior Notes for an aggregate cash payment of $11 million.

During the year ended December 31, 2010, we repurchased an aggregate principal amount of $478 million of the Series C Convertible Senior Notes for an aggregate cash payment of $453 million. In connection with the repurchases, we recognized a loss on retirement of $21 million ($0.07 per diluted share), with no tax effect, associated with the debt components of the repurchased notes, and we recorded additional paid-in capital of $8 million associated with the equity components of the repurchased notes.

Note 15—Derivatives and Hedging

Derivatives designated as hedging instruments—We have interest rate swaps, which are designated and have qualified as fair value hedges, to reduce our exposure to changes in the fair values of the 5% Notes due February 2013 and the 5.25% Senior Notes due March 2013. The interest rate swaps have aggregate notional amounts equal to the corresponding face values of the hedged instruments and have stated maturities that coincide with those of the hedged instruments. We have determined that the hedging relationships qualify for, and we have applied, the shortcut method of accounting, under which the interest rate swaps are considered to have no ineffectiveness and no ongoing assessment of effectiveness is required. Accordingly, changes in the fair value of the interest rate swaps recognized in interest expense offset changes in the fair value of the hedged fixed-rate notes. Through the stated maturities of the interest rate swaps in February and March 2013, we receive semi-annual interest at a fixed rate equal to that of the underlying debt instrument and pay variable interest semi-annually at three-month LIBOR plus a margin.

We previously entered into interest rate swaps, which were designated and qualified as a fair value hedge, to reduce our exposure to changes in the fair values of the 4.95% Senior Notes due November 2015. In June 2012, we terminated these interest rate swaps and received an aggregate net cash payment of $23 million in the year ended December 31, 2012.

We have interest rate swaps, which have been designated and qualify as a cash flow hedge, to reduce the variability of cash interest payments associated with the variable-rate borrowings under the TPDI Credit Facilities through December 31, 2014. The aggregate notional amount corresponds with the aggregate outstanding amount of the borrowings under the TPDI Credit Facilities.

We have cross-currency interest rate swaps, which have been designated and qualify as a cash flow hedge, to reduce the variability of cash interest payments and the final principal payment due at maturity in February 2016 associated with the changes in the U.S. dollar to Norwegian krone exchange rate. The aggregate notional amount corresponds with the aggregate outstanding amount of the 11% Callable Bonds. Our obligations under the swap agreements are secured by the Ultra-Deepwater Floaters Transocean Spitsbergen and Transocean Barents. At December 31, 2012 and 2011, the aggregate carrying amount of Transocean Spitsbergen and Transocean Barents was $1.5 billion.

At December 31, 2012, the aggregate notional amounts and the weighted average interest rates associated with our derivatives designated as hedging instruments were as follows (in millions, except weighted average interest rates):

	Pay			Receive		
	Aggregate notional amount	Fixed or variable rate	Weighted average rate	Aggregate notional amount	Fixed or variable rate	Weighted average rate
Interest rate swaps, fair value hedges	$ 750	variable	3.5%	$ 750	fixed	5.2%
	$ 385	fixed	2.4%	$ 385	variable	0.3%

Interest rate swaps, cash flow hedges						
Cross-currency swaps, cash flow hedges	$ 102	fixed	8.9%	NOK 560	fixed	11.0%

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

	Statement of operations classification	Years ended December 31, 2012	2011	2010
Loss associated with effective portion	Interest expense, net of amounts capitalized	$ (5)	$ (11)	$ (12)
Gain associated with effective portion	Other, net	6	—	—

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, 2012	2011
Interest rate swaps, fair value hedges	Other current assets	$ 6	$ 5
Interest rate swaps, fair value hedges	Other assets	—	31
Interest rate swaps, cash flow hedges	Other long-term liabilities	13	16
Cross-currency swaps, cash flow hedges	Other current assets	1	—
Cross-currency swaps, cash flow hedges	Other assets	1	—
Cross-currency swaps, cash flow hedges	Other long-term liabilities	—	7

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 certain of 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 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 liquidation value of $195 million. The preference shares contain two embedded derivatives, which are not designated and do not qualify as hedging instruments for accounting purposes, including (a) a ceiling dividend rate indexed to the price of Brent Crude oil and (b) a dividend rate premium triggered in the event of credit default. See Note 9—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, 2012	2011	2010
Loss associated with undesignated interest rate swaps	Interest expense, net of amounts capitalized	$ (1)	$ —	$ —
Loss associated with undesignated forward exchange contract	Other, net	—	(78)	—

The balance sheet classification and aggregate carrying amount of our derivatives not designated as hedging instruments, measured at fair value, were as follows (in millions):

	Balance sheet classification	December 31, 2012	2011
		$ —	$ 15

Interest rate swaps not designated as hedging instruments	Other long-term liabilities		
Embedded derivatives not designated as hedging instruments	Other long-term liabilities	2	—

Note 16—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.

TRANSOCEAN LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued

Assumptions—The following were the weighted-average assumptions used to determine benefit obligations:

	December 31, 2012			December 31, 2011
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S.