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

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2011

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.)
Chemin de Blandonnet 10 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

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

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

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

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

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

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

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

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

As of June 30, 2011, 319,639,362 shares were outstanding and the aggregate market value of shares held by non-affiliates was approximately $20.6 billion (based on the reported closing market price of the shares of Transocean Ltd. on such date of $64.56 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 22, 2012, 350,424,694 shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be filed with the Securities and Exchange Commission within 120 days of December 31, 2011, for its 2012 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, 2011

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 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 the 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,
- 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 U.S.,
- legal and regulatory matters, including results and effects of legal proceedings and governmental audits and assessments, outcomes and effects of internal and governmental investigations, customs and environmental matters,
- insurance matters, including adequacy of insurance, renewal of insurance, insurance proceeds and cash investments of our wholly owned captive insurance company,
- effects of accounting changes and adoption of accounting policies, and
- investments in recruitment, retention and personnel development initiatives, pension plan and other postretirement benefit plan contributions, the timing of severance payments and benefit payments.

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

- "anticipates"
- "believes"
- "budgets"
- "could"
- "estimates"
- "expects"
- "forecasts"
- "intends"
- "may"
- "might"
- "plans"
- "predicts"
- "projects"
- "scheduled"
- "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,
- 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 14, 2012, we owned or had partial ownership interests in and operated 134 mobile offshore drilling units. As of this date, our fleet consisted of 50 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters, nine High-Specification Jackups, 49 Standard Jackups and one swamp barge. In addition, we had two Ultra-Deepwater Floaters and four High-Specification Jackups under construction.

We specialize in technically demanding sectors 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. 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 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes to Consolidated Financial Statements—Note 25—Segments, Geographical Analysis and Major Customers.

Recent Developments

In February 2011, we sold the subsidiary that owns the High-Specification Jackup, *Trident 20*, located in the Caspian Sea. In March 2011, 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. and Challenger Minerals (North Sea) Limited (together, "CMI"). As a result of these actions, we reclassified to discontinued operations the operating results and the assets and liabilities associated with our Caspian Sea operations and our oil and gas operations. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited, and in February 2012, entered into an agreement to sell the assets of Challenger Minerals Inc.

In October 2011, we completed our acquisition of Aker Drilling ASA ("Aker Drilling"), a Norwegian company formerly listed on the Oslo Stock Exchange. In connection with the acquisition, we acquired two Harsh Environment, Ultra-Deepwater semisubmersibles currently operating on long-term contracts in Norway. Additionally, we acquired two Ultra-Deepwater drillships currently under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, which have expected deliveries in 2014.

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. Also included in our fleet is a swamp barge drilling unit.

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 and five Enhanced Enterprise-class 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 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 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," (3) "High-Specification Jackups," (4) "Standard Jackups" and (5) a swamp barge. As of February 14, 2012, our fleet of 134 rigs, excluding rigs under construction, was as follows:

- 50 High-Specification Floaters, which are comprised of:
  - 27 Ultra-Deepwater Floaters;
  - 16 Deepwater Floaters; and
  - Seven Harsh Environment Floaters;
- 25 Midwater Floaters;
- Nine High-Specification Jackups;
- 49 Standard Jackups; and
- one swamp barge

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 7,500 and 4,500 feet. Harsh Environment Floaters are capable of drilling in harsh environments in water depths between 10,000 and 1,500 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 are able to operate in harsh environments, and have higher capacity derricks, drawworks, mud systems and storage. Typically, High-Specification Jackups also have deeper water depth capacity than Standard Jackups.

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, 2012, 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, 2012, 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. In addition to the rigs presented below, we also own and operate one swamp barge.

Rigs Under Construction (6)

Name	Type	Expected completion	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Contracted location
Ultra-Deepwater Floaters					
DSME 12000 Drillship TBN1	HSD	1Q 2014	12,000	40,000	To be determined
DSME 12000 Drillship TBN2	HSD	2Q 2014	12,000	40,000	To be determined
High-Specification Jackups					
Transocean Honor	Jackup	1Q 2012	400	30,000	Angola
Transocean Siam Driller	Jackup	1Q 2013	350	35,000	Thailand
Transocean Andaman	Jackup	1Q 2013	350	35,000	Thailand
Transocean Ao Thai	Jackup	3Q 2013	350	35,000	Thailand

"HSD" means high-specification drillship.

High-Specification Floaters (50)

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)	HSD	2009	12,000	40,000	U.S. Gulf
Discoverer Inspiration (b) (c) (d)	HSD	2010	12,000	40,000	U.S. Gulf
Deepwater Champion (b) (c)	HSD	2011	12,000	40,000	Romania/Black Sea
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	Sierra Leone
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	Mozambique
Deepwater Pathfinder (b)	HSD	1998	10,000	30,000	U.S. Gulf
Deepwater Expedition (b)	HSD	1999	8,500	30,000	To be determined
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	Indonesia
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	Israel
Deepwater Floaters (16)					
Deepwater Navigator (b)	HSD	1971/2000	7,200	25,000	Brazil
Discoverer 534 (b)	HSD	1975/1991	7,000	25,000	Stacked
Discoverer Seven Seas (b)	HSD	1976/1997	7,000	25,000	India
Transocean Marianas (g)	HSS	1979/1998	7,000	30,000	Nigeria/Ghana
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
Jim Cunningham (g)	HSS	1982/1995	4,600	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) Owned through our 50 percent interest in Transocean Pacific Drilling Inc. and pledged as collateral for debt of the joint venture company.
(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	Brazil
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	Stacked
Sedco 714	OS	1983/1997	1,600	25,000	U.K. N. Sea
Actinia	OS	1982	1,500	25,000	Malaysia
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	Congo
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
GSF Constellation I	2003	400	30,000	Gabon
GSF Constellation II	2004	400	30,000	Egypt
GSF Galaxy I	1991/2001	400	30,000	Stacked
GSF Galaxy II	1998	400	30,000	U.K. N. Sea
GSF Galaxy III	1999	400	30,000	U.K. N. Sea
GSF Baltic	1983	375	25,000	Nigeria
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.

Standard Jackups (49)

Name	Year entered service/ upgraded (a)	Water depth capacity (in feet)	Drilling depth capacity (in feet)	Location
Trident IX	1982	400	21,000	Malaysia
GSF Adriatic II	1981	350	25,000	Stacked
GSF Adriatic IX	1981	350	25,000	Nigeria
GSF Adriatic X	1982	350	30,000	Nigeria
GSF Key Manhattan	1980	350	25,000	Italy
GSF Key Singapore	1982	350	25,000	Stacked
GSF Adriatic VI	1981	328	25,000	Stacked
GSF Adriatic VIII	1983	328	25,000	Stacked
C. E. Thornton	1974	300	25,000	India
D. R. Stewart	1980	300	25,000	Stacked
F. G. McClintock	1975	300	25,000	India
GSF Adriatic I	1981	300	25,000	Stacked
GSF Adriatic V	1979	300	25,000	Stacked
GSF Compact Driller	1992	300	25,000	Thailand
GSF Galveston Key	1978	300	25,000	Vietnam
GSF Key Gibraltar	1976/1996	300	25,000	Thailand
GSF Key Hawaii	1982	300	25,000	Vietnam
GSF Main Pass I	1982	300	25,000	Arabian Gulf
GSF Main Pass IV	1982	300	25,000	Arabian Gulf
Harvey H. Ward	1981	300	25,000	Indonesia
J. T. Angel	1982	300	25,000	India
Randolph Yost	1979	300	25,000	Stacked
Roger W. Mowell	1982	300	25,000	Stacked
Ron Tappmeyer	1978	300	25,000	India
Transocean Shelf Explorer	1982	300	20,000	Stacked
Interocean III	1978/1993	300	25,000	Stacked
Transocean Nordic	1984	300	25,000	Stacked
Trident II	1977/1985	300	25,000	India
Trident IV-A	1980/1999	300	25,000	Stacked
Trident 17	1983	300	25,000	Stacked
Trident XII	1982/1992	300	25,000	India
Trident XIV	1982/1994	300	25,000	Angola
Trident 15	1982	300	25,000	Thailand
Trident 16	1982	300	25,000	Thailand
Trident VIII	1981	300	21,000	Gabon
GSF Parameswara	1983	300	20,000	Indonesia
GSF Rig 134	1982	300	20,000	Stacked
GSF High Island II	1979	270	20,000	Arabian Gulf
GSF High Island IV	1980/2001	270	20,000	Arabian Gulf
GSF High Island V	1981	270	20,000	Stacked
GSF High Island VII	1982	250	20,000	Nigeria
GSF High Island IX	1983	250	20,000	Arabian Gulf
GSF Rig 103	1974	250	20,000	Stacked
GSF Rig 105	1975	250	20,000	Egypt
GSF Rig 124	1980	250	20,000	Egypt
GSF Rig 127	1981	250	20,000	Stacked
GSF Rig 141	1982	250	20,000	Egypt
Transocean Comet	1980	250	20,000	Egypt
Trident VI	1981	220	21,000	Stacked

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

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, 2012, our fleet was located in the Far East (27 units), Middle East (16 units), West African countries other than Nigeria and Angola (14 units), United States ("U.S.") Gulf of Mexico (13 units), U.K. North Sea (12 units), India (12 units), Brazil (10 units), Nigeria (10 units), Norway (eight units), Angola (four units), Australia (three units), the Mediterranean (two units), Canada (two units), and Romania (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, (3) jackup and (4) transition zone. 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 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.

The transition zone market sector is characterized by marshes, rivers, lakes, and shallow bay and coastal water areas. We only operate in this sector using our swamp barge drilling rig located in Southeast Asia.

Financial Information about Geographic Areas

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

	Years ended December 31,		
	2011	2010	2009
Operating revenues			
U.S.	$ 1,975	$ 2,087	$ 2,209
U.K.	1,211	1,183	1,563
Brazil	1,019	1,288	1,108
Other countries (a)	4,937	4,908	6,561
Total operating revenues	$ 9,142	$ 9,466	$ 11,441

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

	December 31,	
	2011	2010
Long-lived assets		
U.S.	$ 6,549	$ 5,519
Brazil	2,185	2,472
India	1,593	2,632
Other countries (a)	12,202	10,696
Total long-lived assets	$ 22,529	$ 21,319

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

Contract Backlog

Our contract backlog at December 31, 2011 was approximately $22.5 billion, representing an 8.5 percent and 27.7 percent decrease compared to our contract backlog of $24.6 billion and $31.1 billion at December 31, 2010 and 2009, respectively. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Drilling market" and "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.

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 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. See "Item 3. Legal Proceedings—Macondo well incident—Contractual indemnity."

Drilling Management Services

We provide drilling management services primarily on a turnkey basis through Applied Drilling Technology Inc., our wholly owned subsidiary, which primarily operates in the U.S. Gulf of Mexico, 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 turnkey drilling 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 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.

Revenues from these drilling management services represented less than six percent of our consolidated revenues for the year ended December 31, 2011. 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.

Integrated Services

From time to time, we provide well and logistics services in addition to our normal drilling services through third-party contractors and our employees. We refer to these other services as integrated services, which are generally subject to individual contractual agreements executed to meet specific customer needs and may be provided on either a dayrate, cost plus or fixed-price basis, depending on the daily activity. As of February 14, 2012, we were only performing such services in India. Revenues from these integrated services represented less than one percent of our consolidated revenues for the year ended December 31, 2011.

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, India, 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 50 percent interest in Transocean Pacific Drilling Inc. ("TPDI"), a consolidated British Virgin Islands joint venture company formed by us and Quantum Pacific Management Limited, a Cypriot company and successor in interest to Pacific Drilling Limited ("Quantum"), to own and operate two ultra-deepwater drillships named *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. Under a management services agreement with TPDI, we provide operating management services for *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. Quantum has the unilateral right to exchange its interest in the joint venture for our shares or cash, at an amount based on an appraisal of the fair value of the drillships, subject to certain adjustments, but it has not exercised this right.

We hold a 65 percent interest in Angola Deepwater Drilling Company Limited ("ADDCL"), a consolidated Cayman Islands joint venture company formed to own and operate *Discoverer Luanda*. Angco Cayman Limited, a Cayman Islands company, holds the remaining 35 percent interest in ADDCL. Under a management services agreement with ADDCL, we provide operating management services for *Discoverer Luanda*. 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.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Related Party Transactions."

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 and independent oil companies. Our most significant customer in 2011 was BP plc (together with its affiliates, "BP"), accounting for approximately 10 percent of our operating revenues. No other customer accounted for 10 percent or more of our 2011 operating revenues.

Employees

We require highly skilled personnel to operate our drilling units. Consequently, we conduct extensive personnel recruiting, training and safety programs. At December 31, 2011, we had approximately 18,700 employees, including approximately 1,850 persons engaged through contract labor providers. Some of our employees working in Angola, the U.K., Norway and Australia 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.

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 Sub-Arctic, year-round operations, and the latest generations of ultra-deepwater drillships and semisubmersibles. Fifteen rigs in our existing fleet 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 we have patented in certain market sectors in which we operate. 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. 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

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."

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. From a global perspective, we continue to assess further projects designed to reduce our overall emissions. To date, we have not incurred significant 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.

Available Information

Our website address is *www.deepwater.com*. Information contained on or accessible from our website is not incorporated by reference into this annual report on Form 10-K and should not be considered a part of this report or any other filing that we make with the SEC. We make available on this website free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. You may also find 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*, that 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. We may also be subject to governmental fines or penalties. Although we have excess liability insurance coverage, our personal injury and other third party liability insurance coverage is subject to deductibles and overall aggregate policy limits. There can be no assurance that our insurance will ultimately be adequate to cover all of our 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 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. Our business has been negatively impacted by the loss of revenue from *Deepwater Horizon*. The backlog associated with the *Deepwater Horizon* drilling contract was approximately $590 million through the end of the contract term in 2013. We do not carry insurance for business interruption or loss of hire. In the two years ended December 31, 2011, 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. In one case, the increased downtime has resulted in the recent termination of one of our contracts, which represented backlog of approximately $470 million. In the three months ended December 31, 2011, we recognized an estimated loss of $1.0 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 years ended December 31, 2011 and 2010, we incurred incremental costs, primarily associated with legal expenses for lawsuits and investigations, net of expected insurance recoveries, in the amount of $71 million and $139 million, respectively. Collectively, the lost contract backlog from the incident and from the recent termination, lost revenues and incremental expenses from extended shipyard projects and increased downtime, loss contingencies associated with the incident and other incremental costs have had an effect of greater than $3.0 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. As of December 31, 2011, we have recognized a liability for such loss contingencies in the amount of $1.2 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, some of which could occur very soon, 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 10 percent of our consolidated operating revenues for the year ended December 31, 2011. 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 $44.6 billion in relation to the spill. As described under "Part I. Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—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 Clean Water Act. 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.

Investigations are ongoing in connection with the Macondo well incident, the outcome of which are unknown and could have a material adverse effect on us.

On June 28, 2010, we received a letter from the U.S. Department of Justice ("DOJ") asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. We have engaged in discussions with the DOJ and have responded to their document requests, and we expect these discussions to continue. In addition, on December 15, 2010, the DOJ filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleges claims under the Oil Pollution Act of 1990 ("OPA") and the Clean Water Act, including claims for per barrel civil penalties of up to $1,100 per barrel or up to $4,300 per barrel if gross negligence or willful misconduct is established, and the DOJ reserved its rights to amend the complaint to add new claims and defendants. The complaint asserts 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 Clean Water Act, 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 ("The MDL Court") ruled that we are not liable as a responsible party for damages under OPA with respect to the below surface discharges from the Macondo well. The 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 Clean Water Act, and that we therefore are not liable for such discharges as an owner of the vessel under the Clean Water Act. However, the court ruled that the issue of whether we could be held liable for such discharge under the Clean Water Act 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.

In addition to the civil complaint, the DOJ served us with civil investigative demands on December 8, 2010. These demands were part of an investigation by the DOJ to determine if we made false claims, or false statements in support of claims, in connection with the operator's acquisition of the leasehold interest in the Mississippi Canyon Block 252, Gulf of Mexico and drilling operations on *Deepwater Horizon*.

The DOJ is also conducting a criminal investigation into the Macondo well incident. The DOJ task force is investigating possible violations, by us and certain unaffiliated parties, of the Clean Water Act, 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. Under the Alternative Fines Act, a corporate defendant convicted of a criminal offense may be subject to a fine in the amount of twice the gross pecuniary loss suffered by third parties as a result of the offense.

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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident—Investigations."

We cannot predict the ultimate outcome of the DOJ's lawsuit 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, the potential impact of implementing measures that may result 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 recommended practice 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 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 affect 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, and a Brazilian federal police marshal has filed a report recommending the criminal indictment of 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, there is a risk that Brazilian authorities could temporarily or permanently enjoin us from further operations in Brazil. For the year ended December 31, 2011, our operations in Brazil accounted for 11 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.

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 $13.5 billion and $11.2 billion at December 31, 2011 and 2010, 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 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;
- less levered competitors could have a competitive advantage because they have lower debt service requirements; 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 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 limit our ability to refinance our existing debt, could cause us to refinance or issue debt with less favorable terms and conditions and could increase certain fees under our credit facilities and interest rates under agreements governing certain of our senior notes and cause indebtedness of approximately $30 million to become due. In addition, such ratings levels could negatively impact current and prospective customers' willingness to transact business with us and could impose additional insurance requirements. 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, and Moody's Investors Service currently has such debt on review for further downgrade. Any further downgrade by any of the rating agencies could have the effect 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."

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 navigable U.S. waters and 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. Numerous lawsuits, including one brought by the DOJ, allege that we may have liability under the environmental laws relating to the Macondo well incident. If we are charged with or convicted of certain criminal environmental offenses, we may be subject to suspension or debarment as a contractor or subcontractor on certain government contracts, including leases. 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 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 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. 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 commodity prices do not necessarily translate into increased drilling activity since customers' expectations of 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, 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.

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 energy-consuming markets;
- the ability of the Organization of the Petroleum Exporting Countries ("OPEC") to set and maintain production levels 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; and
- the worldwide military and political environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities, civil unrest or other crises in the Middle East or other geographic areas or further acts of terrorism in the U.S., or elsewhere.

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 may also be 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. Since the onset of the worldwide financial and economic downturn, we have experienced weakness in our Midwater Floater, High-Specification Jackups and Standard Jackup market sectors. 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 utilization, industry participants have increased the supply of rigs by ordering the construction of new units. This has typically resulted in an oversupply of rigs and has caused a subsequent decline in dayrates and utilization, 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. Additionally, as a result of the Aker Drilling acquisition we are expected to take delivery, in 2014, of two Ultra-Deepwater drillships currently under construction. We have not yet secured a drilling contract for either drillship. Our failure to secure a drilling contract for either rig prior to its deployment could adversely affect our results of operations. Any further increase in construction of new units would likely exacerbate the negative impact on dayrates and utilization. Lower dayrates and utilization could adversely affect our revenues and profitability.

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 and independent oil companies. Our most significant customer in 2011 was BP, accounting for 10 percent of our operating revenues for the year ended December 31, 2011. As of February 14, 2012, the contract backlog associated with our contracts with BP and its affiliates was $2.7 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 this customer or another significant customer could, at least in the short term, have a material adverse effect on our results of operations and cash flows.

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 14, 2012, we had two Ultra-Deepwater Floater and four 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;
- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- engineering problems, including those relating to the commissioning of newly designed equipment;
- work stoppages;
- customer acceptance delays;
- weather interference or storm damage;
- 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.

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 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 with us may also be negatively impacted by the economic downturn. 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.

Our contract backlog as of February 14, 2012 was approximately \$21.4 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. 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, and these liquidity issues could increase 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 disturbances;
- seizure, expropriation or nationalization of equipment;
- imposition of trade barriers;
- import-export quotas;
- wage and price controls;
- changes in law and regulatory requirements, including changes in interpretation and enforcement;
- damage to our equipment or violence directed at our employees, including kidnappings;
- civil unrest resulting in suspension of operations;
- 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. We have received and responded to an administrative subpoena from OFAC concerning our 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. 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. 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. 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. The global economic downturn may increase some foreign government's 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.

Failure to comply with the U.S. Foreign Corrupt Practices Act and the Bribery Act 2010 recently enacted by the U.K. 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 Bribery Act 2010 which became effective in the U.K. 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, stockholders, 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."

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., Norway and Australia, 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.

The worldwide financial and economic downturn reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with losses in worldwide equity markets led to an extended worldwide economic recession. Our ability to access the capital 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. Recent worldwide economic conditions impacted lenders participating in our credit facilities and our customers, and another economic shock could cause them to fail to meet their obligations to us. The slowdown in economic activity caused by the recession also reduced worldwide demand for energy and resulted in an extended period of lower oil and natural gas prices. Crude oil prices, although rebounded from the low levels experienced in early 2009, have declined from record levels in July 2008, and natural gas prices have also experienced sharp declines. Declines in commodity prices, along with difficult conditions in the credit markets, have had a negative impact on our business, and this impact could continue or worsen.

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 and war perils worldwide. We also generally self-insure coverage on our Standard Jackup fleet and our swamp barge for expenses incurred by ADTI and CMI related to well control and redrill liability for well blowouts. As of December 31, 2011 the aggregate net carrying amount of the Standard Jackup fleet and swamp barge is approximately $1.6 billion.

With respect to our hull and machinery coverage, we maintain a $125 million per occurrence deductible for damage to our rigs and offshore drilling equipment included in the coverage. 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 $950 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 $132 million of this policy in addition to the $50 million self-insured retention noted above, and we re-insured $25 million of this amount in 2011. There is no guarantee that we will be successful in re-insuring any or all of this amount, and we may retain the risks associated with this portion of our excess liability coverage.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a customer, 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. In addition, we have decided to generally retain the risk associated with our Standard Jackup and barge fleets and we could decide to retain substantially more risk in the future. 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.

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 Copenhagen in 2009. Also, the U.S. Environmental Protection Agency ("EPA") has undertaken new 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, 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. Additionally, EPA has issued a "Mandatory Reporting of Greenhouse Gases" final rule, which establishes a new comprehensive scheme requiring operators of stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually. In late 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule, and will require facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year to report annual GHG emissions, with the first report due on March 31, 2012.

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. 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.

Failure to retain key personnel could hurt our operations.

We require highly skilled personnel to operate and provide technical services and support for our business worldwide. Historically, competition for the labor 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 labor were to intensify in the future we may experience increases in costs or limits on operations.

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 to 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. 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 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 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.

We are protected to some extent against loss of capital assets, but generally not loss of revenue, from most of these risks through indemnity provisions in our drilling contracts. Our assets, however, are generally not insured against risk of loss due to perils such as terrorist acts, civil unrest, expropriation, nationalization and acts of war.

Other risks

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

At December 31, 2011, the carrying amount of our property and equipment was $22.5 billion, representing 64 percent of our total assets, and the carrying amount of our goodwill was $3.2 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.

As of October 1, 2011, we recognized an estimated loss of $5.2 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. In the fourth quarter of 2010, we recognized a loss of $1.0 billion on the impairment of our Standard Jackup asset group due to projected declines in dayrates and utilization, and we have previously recognized other losses on impairment of goodwill and other intangible assets. Continued or future expectations of low dayrates and utilization 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 or other intangible assets 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, goodwill or other intangible assets may be impaired.

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

We operate worldwide through our various subsidiaries. Consequently, we are subject to changes in applicable tax laws, treaties or regulations in the jurisdictions in which we operate, which could include laws or policies directed toward companies organized in jurisdictions with low tax rates. A material change in the tax laws 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, the U.S. Congress has recently 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 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. We cannot be certain that the Norwegian authorities will not be successful in proving their allegations in a Norwegian court of law. If they are successful, our earnings and cash flows from operations could be adversely affected.

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 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 ("NOL") carryforwards before they expire. We have established a valuation allowance against the future tax benefit for a number of our non-U.S. NOL 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 NOL carryforwards are subject to review and potential disallowance upon audit by the tax authorities of the jurisdictions where the NOLs 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 issuance of shares, our available authorized share capital decreased to 10.17 percent of our existing 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 $16.48 based on a foreign exchange rate of USD 1.00 to CHF 0.91 on February 22, 2012), 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 10.17 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;
- corporate offices in Zug, Switzerland; Houston, Texas; Cayman Islands, Barbados and Luxembourg; and
- a regional operational office in France.

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

Item 3. Legal Proceedings

Macondo well incident

Overview—On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig. Eleven persons were declared dead and others were injured as a result of the incident. At the time of the explosion, *Deepwater Horizon* was located approximately 41 miles off the coast of Louisiana in Mississippi Canyon Block 252 and was contracted to BP America Production Co.

The MDL Court has issued an order outlining the trial plan, which will proceed in three phases. The first phase will focus on issues arising out of the conduct of various parties, relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on *Deepwater Horizon* on April 20, 2010, the sinking of *Deepwater Horizon* on April 22, 2010, and the initiation of the release of oil during those time periods. The second phase will address conduct relating 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 that time period. The third, and final, phase will involve consideration of issues relating to containing oil discharged by controlled burning, application of dispersants, use of booms, skimming and other methods, as well as issues pertaining to the migration paths and end locations of oil released.

Trial is currently scheduled to commence on March 5, 2012. There can be no assurance as to the outcome of the trial, that the trial will proceed according to the proposed schedule, 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 the trial, or as to the timing or terms of any such settlement.

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. As of December 31, 2011, we have recognized a liability for such loss contingencies in the amount of $1.2 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. As of December 31, 2011, we have also recognized an asset of $220 million associated with the portion of our estimated losses that we believe is recoverable from insurance. Although we have available policy limits that could result in additional amounts recoverable from insurance, we are not currently able to estimate the amount of such additional recoverable amounts. Our estimates involve a significant amount of judgment. As a result of new information or future developments, some of which could occur very soon, 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. See "—Contractual indemnity."

Litigation—As of December 31, 2011, 349 actions or claims were pending against us and certain of our subsidiaries, along with other unaffiliated defendants, in state and federal courts. Additionally, government agencies have initiated investigations into the Macondo well incident. We have categorized below the nature of the legal actions or claims. We are evaluating all claims and intend to vigorously defend any claims and pursue any and all defenses available. In addition, we believe we are entitled to contractual defense and indemnity for all wrongful death and personal injury claims made by non-employees and third-party subcontractors' employees as well as all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See "—Contractual indemnity."

Wrongful death and personal injury—As of December 31, 2011, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in 34 complaints that were pending in state and federal courts in Louisiana and Texas involving multiple plaintiffs that allege wrongful death and other personal injuries arising out of the Macondo well incident. Per the order of the Multi-District Litigation Panel (the "MDL"), these claims have been centralized for discovery purposes in the MDL Court. The complaints generally allege, among other things, negligence and seek awards of unspecified economic damages and punitive damages. BP, MI-SWACO, Weatherford Ltd. and Cameron International Corporation and certain of its affiliates, have, based on contractual arrangements, also made indemnity demands upon us with respect to personal injury and wrongful death claims asserted by our employees or representatives of our employees against these entities. See "—Contractual indemnity."

Economic loss—As of December 31, 2011, we and one or more of our subsidiaries were named, along with other unaffiliated defendants, in 114 individual complaints as well as 184 putative class-action complaints that were pending in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Florida and possibly other courts. The complaints generally allege, among other things, economic losses as a result of environmental pollution arising out of the Macondo well incident and are based primarily on OPA and state OPA analogues. Certain claims were dismissed in a court ruling on August 26, 2011. See "—Environmental matters." The plaintiffs are generally seeking awards of unspecified economic, compensatory and punitive damages, as well as injunctive relief. See "—Contractual indemnity."

Federal securities claims—Two federal securities law class actions are currently pending in the U.S. District Court, Southern District of New York, naming us and certain of our officers and directors as defendants. One of these actions generally allege violations of Section 10(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), Rule 10b-5 promulgated under the Exchange Act and Section 20(a) of the Exchange Act in connection with the Macondo well incident. The plaintiffs are generally seeking awards of unspecified economic damages, including damages resulting from the decline in our stock price after the Macondo well incident. The other action was filed by a former GlobalSantaFe Corporation ("GlobalSantaFe") shareholder, alleging that the proxy statement related to our shareholder meeting in connection with our merger with GlobalSantaFe violated Section 14(a) of the Exchange Act, Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The plaintiff claims that GlobalSantaFe shareholders received inadequate consideration for their shares as a result of the alleged violations and seeks rescission and compensatory damages. The defendants have filed motions to dismiss each of these claims, and the plaintiffs have responded. The motions have been fully briefed and are pending rulings by the courts.

Shareholder derivative claims—In June 2010, two shareholder derivative suits were filed by our shareholders naming us as a nominal defendant and certain of our officers and directors as defendants in the District Courts of the State of Texas. The first case generally alleges breach of fiduciary duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets in connection with the Macondo well incident and the other generally alleges breach of fiduciary duty, unjust enrichment and waste of corporate assets in connection with the Macondo well incident. The plaintiffs are generally seeking, on behalf of us, restitution and disgorgement of all profits, benefits and other compensation from the defendants. Under current schedule orders, an amended consolidated complaint must be filed by the plaintiffs by March 5, 2012.

Limitation of liability action—At the instruction of our insurers and to preserve our insurance coverage, pursuant to the federal Limitation of a Shipowner's Liability Act (the "Limitation Act"), we filed a complaint in the Houston Division of the Southern District of Texas on May 13, 2010 regarding the casualty of the *Deepwater Horizon* rig. The action has been transferred to the U.S. District Court, Eastern District of Louisiana for further proceedings. Under the Limitation Act, a vessel owner is generally liable only for the post-accident value of the vessel and cargo as long as the vessel owner can show that it had no knowledge of or privity of knowledge with entities that were negligent. Claims limited under the Limitation Act include personal injury, wrongful death, and damage to property contained on the rig.

Pursuant to the Limitation Act, we are seeking an injunction staying certain lawsuits underway in jurisdictions other than the Eastern District of Louisiana. In addition, we are seeking to limit our liability for personal injury, wrongful death and damage to property contained on the rig to $27 million, the value of the rig and its freight, including the accounts receivable and accrued accounts receivable, as of April 28, 2010. One objective of the filing is to consolidate lawsuits relating to the *Deepwater Horizon* casualty and to process these lawsuits and claims in an orderly fashion, before a single federal judge. The filing also seeks to establish a single fund from which legitimate claims may be paid.

Environmental matters—Environmental claims under two different schemes, statutory and common law, and in two different regimes, federal and state, have been asserted against us. See "—Litigation—Economic loss." Liability under many statutes is imposed without fault, but such statutes often allow the amount of damages to be limited. In contrast, common law liability requires proof of fault and causation, but generally has no readily defined limitation on damages, other than the type of damages that may be redressed. We have described below certain significant applicable environmental statutes and matters relating to the Macondo well incident.

OPA imposes strict liability on responsible parties of vessels or facilities from which oil is discharged into or upon navigable waters or adjoining shore lines. OPA defines the responsible parties with respect to the source of discharge. Responsible parties for discharges are liable for: (1) removal and cleanup costs, (2) damages that result from the discharge, including natural resources damages, generally up to a statutorily defined limit, (3) reimbursement for government efforts and (4) certain other specified damages. For responsible parties of MODUs, the limitation on liability is determined based on the gross tonnage of the vessel. The statutory limits are not applicable, however, if the discharge is the result of gross negligence, willful misconduct, or violation of federal construction or permitting regulations by the responsible party or a party in a contractual relationship with the responsible party.

The National Pollution Funds Center ("NPFC"), a division of the U.S. Coast Guard, is charged with administering the Oil Spill Liability Trust Fund ("OSLTF"). The NPFC collects fines and civil penalties under OPA from responsible parties, as defined in the statute. The payments are directed to the OSLTF. To date, the NPFC has issued twelve invoices to BP, Anadarko Petroleum Corporation (together with its affiliates, "Anadarko") and MOEX Offshore LLC (together with its affiliates, "MOEX"), as the operator and leasehold owners of the well and, thus, the statutorily defined responsible parties for discharges from the well and wellhead. To date, BP has paid eleven of the twelve invoices. Invoices have also been sent to us, and we have acknowledged responsible party status only with respect to discharges from the vessel on or above the surface of the water, if any.

On December 15, 2010, the DOJ filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleges claims under OPA and the Clean Water Act, including claims for per barrel civil penalties of up to $1,100 per barrel, or up to $4,300 per barrel if gross negligence or willful misconduct is established. The U.S. government has estimated that up to 4.1 million barrels of oil were discharged and subject to penalties. The DOJ reserved its rights to amend the complaint to add new claims and defendants. The complaint asserts that all defendants named 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 Clean Water Act, for all of the 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*. We believe that the owner or operator of a mobile offshore drilling unit ("MODU"), such as *Deepwater Horizon*, is only a responsible party with respect to discharges from the vessel that occur on or above the surface of the water. As the responsible party for *Deepwater Horizon*, we believe we are responsible only for the discharges of oil emanating from the rig above the surface of the water. Therefore, we believe we are not responsible for the discharged hydrocarbons from the Macondo well. On January 9, 2012, we filed our opposition to the motion and filed a cross-motion for partial summary judgment seeking a ruling that we are not liable or the subsurface discharge of hydrocarbons. On February 22, 2012, the MDL Court ruled that we are not liable as a responsible party for damages under OPA with respect to the below surface discharges from the Macondo well. The 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 Clean Water Act, and that we therefore are not liable for such discharges as an owner of the vessel under the Clean Water Act. However, the court ruled that the issue of whether we could be held liable for such discharge under the Clean Water Act 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.

In addition to the civil complaint, the DOJ served us with Civil Investigative Demands ("CIDs") on December 8, 2010. These demands were part of an investigation by the DOJ to determine if we made false claims, or false statements in support of claims, in connection with the operator's acquisition of the leasehold interest in the Mississippi Canyon Block 252, Gulf of Mexico and the drilling operations on *Deepwater Horizon.*

The DOJ is also conducting a criminal investigation of the Macondo well incident. Other investigations are pending or have been concluded in connection with the incident. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident."

We have also received claims directly from individuals, pursuant to OPA, requesting compensation for loss of income as a result of the Macondo well incident. BP has accepted responsible party status with the U.S. Coast Guard for the release of hydrocarbons from the Macondo well and has stated its intent to pay all legitimate claims, and we have not paid any of these claims.

Other federal statutes—Several of the claimants have made assertions under other statutes, including the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Air Act, the Comprehensive Environmental Response Compensation and Liability Act and the Emergency Planning and Community Right-to-Know Act.

State environmental laws—As of December 31, 2011, claims had been asserted by private claimants under state environmental statutes in Florida, Louisiana, Mississippi and Texas. As described below, claims asserted by various state and local governments are pending in Alabama, Florida, Louisiana and Texas.

In June 2010, the Louisiana Department of Environmental Quality (the "LDEQ") issued a consolidated compliance order and notice of potential penalty to us and certain of our subsidiaries asking us to eliminate and remediate discharges of oil and other pollutants into waters and property located in the State of Louisiana, and to submit a plan and report in response to the order. We requested that the LDEQ rescind the enforcement actions against us and our subsidiaries because the remediation actions that are the subject of such orders are actions that do not involve us or our subsidiaries, as we are not involved in the remediation or clean-up activities. Alternatively, if the LDEQ would not rescind the enforcement actions altogether, we requested the LDEQ to dismiss the enforcement actions against us and certain of our subsidiaries as these entities are not proper parties to the enforcement actions and were improperly served. In October 2010, the LDEQ rescinded its enforcement actions against us and our subsidiaries but reserved its rights to seek civil penalties for future violations of the Louisiana Environmental Quality Act.

In September 2010, the State of Louisiana filed a declaratory judgment seeking to designate us as a responsible party under OPA and the Louisiana Oil Spill Prevention and Response Act ("LOSPRA") for the discharges emanating from the Macondo well. Specifically the declaratory judgment claims (1) that we are a responsible party under OPA for all hydrocarbons discharged from the Macondo well, including underwater discharges of oil from the well head; (2) that we, as a responsible party, are jointly, severally, and strictly liable for the spill from the Macondo well in accordance with OPA; (3) that we are a responsible party under the Louisiana Oil Spill Prevention and Response Act for all hydrocarbons discharged from the Macondo well, including underwater discharges of oil from the well head; (4) that we, as a responsible party, are jointly, severally, and strictly liable for the spill from the Macondo well in accordance with the LOSPRA; and (5) seeks an award Plaintiff's costs incurred in pursuing this action as allowed by law.

Additionally, suits have been filed by the State of Alabama and the cities of Greenville, Evergreen, Georgiana and McKenzie, Alabama in the U.S. District Court, Middle District of Alabama; the Mexican States of Veracruz, Quintana Roo and Tamaulipas in the U.S. District Court, Western District of Texas; and the City of Panama City Beach, Florida in the U.S. District Court, Northern District of Florida. Suits were also filed by the City of New Orleans, by and on behalf of multiple Parishes, and by or on behalf of the Town of Grand Isle, Grand Isle Independent Levee District, the Town of Jean Lafitte, the Lafitte Area Independent Levee District, The City of Gretna, the City of Westwego, and the City of Harahan in the U.S. District Court, Eastern District of Louisiana. Additional suits were filed by or on behalf of other Parishes in the respective Parish courts and were removed to federal court. A local government master complaint also was filed in which cities, municipalities, and other local government entities can and have joined. Generally, these governmental entities allege economic losses under OPA and other statutory environmental state claims and also assert various common law state claims. The claims have been centralized in the MDL Court and will proceed in accordance with the MDL scheduling order, and the City of Panama City Beach's claim was voluntarily dismissed.

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

The Mexican States' OPA claims were dismissed for failure to demonstrate that recovery under OPA was authorized by treaty or executive agreement. This ruling may be appealed.

By letter dated May 5, 2010, the Attorneys General of the five Gulf Coast states of Alabama, Florida, Louisiana, Mississippi and Texas informed us that they intend to seek recovery of pollution clean-up costs and related damages arising from the Macondo well incident. In addition, by letter dated June 21, 2010, the Attorneys General of the 11 Atlantic Coast states of Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Rhode Island and South Carolina informed us that their states have not sustained any damage from the Macondo well incident but they would like assurances that we will be responsible financially if damages are sustained. We responded to each letter from the Attorneys General and indicated that we intend to fulfill our obligations as a responsible party for any discharge of oil from *Deepwater Horizon* on or above the surface of the water, and we assume that the operator will similarly fulfill its obligations under OPA for discharges from the undersea well. Other than the lawsuits filed by the states discussed above, no further requests have been made or actions taken subsequent to the initial communication.

Wreck removal—By letter dated December 6, 2010, the Coast Guard requested us to formulate and submit a comprehensive oil removal plan to remove any diesel fuel contained in the sponsons and fuel tanks that can be recovered from *Deepwater Horizon.* We have conducted a survey of the rig wreckage and have confirmed that no diesel fuel remains on the rig. We have insurance coverage for wreck removal for up to 25 percent of *Deepwater Horizon's* insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our remaining excess liability limits.

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

Although we believe we are entitled to contractual defense and indemnity, given the potential amounts involved in connection with the Macondo well incident, the operator has sought to avoid its indemnification obligations. In particular, the operator, in response to our request for indemnification, has generally reserved all of its rights and stated that it could not at this time conclude that it is obligated to indemnify us. In doing so, the operator has asserted that the facts are not sufficiently developed to determine who is responsible and has cited a variety of possible legal theories based upon the contract and facts still to be developed. We believe this reservation of rights is without justification and that the operator is required to honor its indemnification obligations contained in our contract and described above.

In April 2011, BP filed a claim seeking a declaration that it is not liable to us in contribution, indemnification, or otherwise. On November 1, 2011, we filed a motion for partial summary judgment, seeking enforcement of the indemnity obligations for pollution and civil fines and penalties contained in the drilling contract with BP. 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 civil penalties under the Clean Water Act or for punitive damages. 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 vitiate BP's indemnity obligations. Our motion for partial summary judgment and the court's ruling did not address the issue of contractual indemnity for criminal fines and penalties. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy.

Other legal proceedings

Brazil Frade field incident—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 Frade field with *Sedco 706*. The release was ultimately controlled and the well was plugged. The oil released is in the process of being contained by Chevron.

On or about December 13, 2011, a federal prosecutor in the town of Campos in Rio de Janeiro State filed a civil public action against Chevron and us seeking 20.0 billion Brazilian reals, equivalent to approximately $11.0 billion, and seeking a preliminary and permanent injunction preventing Chevron and us from operating in Brazil. The prosecutor amended the requested injunction on December 15, 2011, to seek 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. The complaint has not been served on us. On January 11, 2012, a judge of the federal court in Campos issued an order finding that the case should be transferred to the federal court in Rio de Janeiro.

On December 21, 2011, a federal police marshal investigating the release filed a report with the federal court in Rio de Janeiro State recommending the indictment of Chevron, us, and 17 individuals, five of which are our employees. The report recommended indictment on four counts, three alleging environmental offenses and one alleging false statements by Chevron in connection with its cleanup efforts. The federal court in Rio de Janeiro State has forwarded the report to the federal court in Campos for a decision on the proper jurisdiction for the matter. In addition, there is a risk that Brazilian authorities could temporarily or permanently enjoin us from further operations in Brazil.

The drilling services and charter contracts between us and Chevron provides, among other things, for Chevron to indemnify and defend us for claims based on pollution or contamination originating from below the surface of the water, including claims for control or removal or property loss or damage, including but not limited to third-party claims and liabilities, with an excludable amount of $250,000 per occurrence if the claim arises from our negligence.

We believe that we have valid defenses to the threatened civil and criminal claims by the federal prosecutor and intend to defend vigorously against any claims that are brought based on the incident. We also intend to pursue indemnity rights under our contracts with Chevron.

Asbestos litigation—In 2004, several of our subsidiaries were named, along with numerous other unaffiliated defendants, in 21 complaints filed on behalf of 769 plaintiffs in the Circuit Courts of the State of Mississippi and which claimed injuries arising out of exposure to asbestos allegedly contained in drilling mud during these plaintiffs' employment in drilling activities between 1965 and 1986. Each individual plaintiff was subsequently required to file a separate lawsuit, and the original 21 multi-plaintiff complaints were then dismissed by the Circuit Courts. The amended complaints resulted in one of our subsidiaries being named as a direct defendant in seven cases. We have or may have an indirect interest in an additional 12 cases. The complaints generally allege that the defendants used or manufactured asbestos-containing drilling mud additives for use in connection with drilling operations and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. The plaintiffs generally seek awards of unspecified compensatory and punitive damages. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling-related products that contained asbestos. All of these cases are being governed for discovery and trial setting by a single Case Management Order entered by a Special Master appointed by the Court to reside over all the cases, and none of the seven cases in which we are a named defendant have been scheduled for trial or pre-trial discovery. The preliminary information available on these claims is not sufficient to determine if there is an identifiable period for alleged exposure to asbestos, whether any asbestos exposure in fact occurred, the vessels potentially involved in the claims, or the basis on which the plaintiffs would support claims that their injuries were related to exposure to asbestos. However, the initial evidence available would suggest that we would have significant defenses to liability and damages. We intend to defend these lawsuits vigorously, although there can be no assurance as to the ultimate outcome. We historically have maintained broad liability insurance, although we are not certain whether insurance will cover the liabilities, if any, arising out of these claims. Based on our evaluation of the exposure to date, we do not expect the liability, if any, resulting from these claims to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

One of our subsidiaries was involved in lawsuits arising out of the subsidiary's involvement in the design, construction and refurbishment of major industrial complexes. The operating assets of the subsidiary were sold and its operations discontinued in 1989, and the subsidiary has no remaining assets other than the insurance policies involved in its litigation, with its insurers and, either directly or indirectly as the beneficiary of a qualified settlement fund, funding from settlements with insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers, and funds received from the communication of certain insurance policies. The subsidiary has been named as a defendant, along with numerous other companies, in lawsuits alleging bodily injury or personal injury as a result of exposure to asbestos. As of December 31, 2011, the subsidiary was a defendant in approximately 950 lawsuits. Some of these lawsuits include multiple plaintiffs and we estimate that there are approximately 2,114 plaintiffs in these lawsuits. For many of these lawsuits, we have not been provided with sufficient information from the plaintiffs to determine whether all or some of the plaintiffs have claims against the subsidiary, the basis of any such claims, or the nature of their alleged injuries. The first of the asbestos-related lawsuits was filed against this subsidiary in 1990. Through December 31, 2011, the amounts expended to resolve claims, including both defense fees and expenses and settlement costs, have not been material, all known deductibles have been satisfied or are inapplicable, and the subsidiary's defense fees and expenses and costs of settlement have been met by insurance made available to the subsidiary. The subsidiary continues to be named as a defendant in additional lawsuits, and we cannot predict the number of additional cases in which it may be named a defendant nor can we predict the potential costs to resolve such additional cases or to resolve the pending cases. However, the subsidiary has in excess of $1.0 billion in insurance limits potentially available to the subsidiary. Although not all of the policies may be fully available due to the insolvency of certain insurers, we believe that the subsidiary will have sufficient funding from settlements and claims payments from insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers to respond to these claims. While we cannot predict or provide assurance as to the final outcome of these matters, we do not believe that the current value of the claims where we have been identified will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Rio de Janeiro tax assessment—In the third quarter of 2006, we received tax assessments of approximately $187 million from the state tax authorities of Rio de Janeiro in Brazil against one of our Brazilian subsidiaries for taxes on equipment imported into the state in connection with our operations. The assessments resulted from a preliminary finding by these authorities that our subsidiary's record keeping practices were deficient. We currently believe that the substantial majority of these assessments are without merit. We filed an initial response with the Rio de Janeiro tax authorities on September 9, 2006 refuting these additional tax assessments. In September 2007, we received confirmation from the state tax authorities that they believe the additional tax assessments are valid, and as a result, we filed an appeal on September 27, 2007 to the state Taxpayer's Council contesting these assessments. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Brazilian import license assessment—In the fourth quarter of 2010, one of our Brazilian subsidiaries received an assessment from the Brazilian federal tax authorities in Rio de Janeiro of approximately $235 million based upon the alleged failure to timely apply for import licenses for certain equipment and for allegedly providing improper information on import license applications. We responded to the assessment on December 22, 2010, and we currently believe that a substantial majority of the assessment is without merit. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other matters—We are involved in various tax matters and various regulatory matters. We are also involved in lawsuits relating to damage claims arising out of hurricanes Katrina and Rita, all of which are insured and which are not material to us. In addition, as of December 31, 2011, we were involved in a number of other lawsuits, including a dispute for municipal tax payments in Brazil and a dispute involving customs procedures in India, neither of which is material to us, and all of which have arisen in the ordinary course of our business. We do not expect the liability, if any, resulting from these other matters to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such other pending or threatened litigation. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

Other environmental matters

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

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

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

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

- the actual responsibility attributed to us and the other PRPs at the site;
- appropriate investigatory or remedial actions; and
- allocation of the costs of such activities among the PRPs and other site users.

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

- the volume and nature of material, if any, contributed to the site for which we are responsible;
- the number of other PRPs and their financial viability; and
- the remediation methods and technology to be used.

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

Contamination litigation

On July 11, 2005, one of our subsidiaries was served with a lawsuit filed on behalf of three landowners in Louisiana in the 12th Judicial District Court for the Parish of Avoyelles, State of Louisiana. The lawsuit named 19 other defendants, all of which were alleged to have contaminated the plaintiffs' property with naturally occurring radioactive material, produced water, drilling fluids, chlorides, hydrocarbons, heavy metals and other contaminants as a result of oil and gas exploration activities. Experts retained by the plaintiffs issued a report suggesting significant contamination in the area operated by the subsidiary and another codefendant, and claimed that over $300 million would be required to properly remediate the contamination. The experts retained by the defendants conducted their own investigation and concluded that the remediation costs would amount to no more than $2.5 million.

The plaintiffs and the codefendant threatened to add GlobalSantaFe as a defendant in the lawsuit under the "single business enterprise" doctrine contained in Louisiana law. The single business enterprise doctrine is similar to corporate veil piercing doctrines. On August 16, 2006, our subsidiary and its immediate parent company, each of which is an entity that no longer conducts operations or holds assets, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. Later that day, the plaintiffs dismissed our subsidiary from the lawsuit. Subsequently, the codefendant filed various motions in the lawsuit and in the Delaware bankruptcies attempting to assert alter ego and single business enterprise claims against GlobalSantaFe and two other subsidiaries in the lawsuit. The efforts to assert alter ego and single business enterprise theory claims against GlobalSantaFe were rejected by the Court in Avoyelles Parish, and the lawsuit against the other defendant went to trial on February 19, 2007. This lawsuit was resolved at trial with a settlement by the codefendant that included a $20 million payment and certain cleanup activities to be conducted by the codefendant. The codefendant further claimed to receive a right to continue to pursue the original plaintiff's claims.

The codefendant sought to dismiss the bankruptcies. In addition, the codefendant filed proofs of claim against both our subsidiary and its parent with regard to its claims arising out of the settlement of the lawsuit. On February 15, 2008, the Bankruptcy Court denied the codefendant's request to dismiss the bankruptcy case but modified the automatic stay to allow the codefendant to proceed on its claims against the debtors, our subsidiary and its parent, and their insurance companies. The codefendant subsequently filed suit against the debtors and certain of its insurers in the Court of Avoyelles Parish to determine their liability for the settlement. The denial of the motion to dismiss the bankruptcies was appealed. On appeal the bankruptcy cases were ordered to be dismissed, and the bankruptcies were dismissed on June 14, 2010.

On March 10, 2010, GlobalSantaFe and the two subsidiaries filed a declaratory judgment action in State District Court in Houston, Texas against the codefendant and the debtors seeking a declaration that GlobalSantaFe and the two subsidiaries had no liability under legal theories advanced by the codefendant. This action is currently stayed.

On March 11, 2010, the codefendant filed a motion for leave to amend the pending litigation in Avoyelles Parish to add GlobalSantaFe, Transocean Worldwide Inc., its successor and our wholly owned subsidiary, and one of the subsidiaries as well as various additional insurers. Leave to amend was granted and the amended petition was filed. An extension to respond for all purposes was agreed until April 28, 2010 for the debtors, GlobalSantaFe, Transocean Worldwide Inc. and the subsidiary. On April 28, 2010, GlobalSantaFe and its two subsidiaries filed various exceptions seeking dismissal of the Avoyelles Parish lawsuit, which have been denied. Subsequent to denial, GlobalSantaFe and its two subsidiaries filed supervisory writs with the Third Circuit Court of Appeals for the State of Louisiana.

On December 15, 2010, as permitted under the existing Case Management Order, GlobalSantaFe and various subsidiaries served third-party demands joining various insurers in the Avoyelles Parish lawsuit seeking insurance coverage for the claims brought against GlobalSantaFe and such subsidiaries. On January 27, 2011, one of the insurers filed pleadings removing the Avoyelles Parish lawsuit to the United States District Court for the Western District of Louisiana, Alexandria Division (the "Western District Action"). On February 3, 2011, GlobalSantaFe and the two subsidiaries filed motions to dismiss the Western District Action, which are now pending. A motion to remand was filed by the codefendant and a hearing on the motion was held on April 5, 2011. A report and recommendations were issued on April 25, 2011 by the magistrate in favor of granting the motion to remand. Objections to this report were filed with the district court. On September 27, 2011 the district court adopted the report and recommendations and remanded the matter to the state court in Avoyelles Parish. Separately, the removing insurer has filed an appeal of the United States Court of Appeals for the Fifth Circuit challenging the remand order and seeking to stay or enjoin the state court from proceeding until a determination of the appeal. The appeal is currently pending in the initial briefing state.

Subsequent to the remand, a scheduling order has been entered in the Avoyelles Parish lawsuit and a jury trial is set for September 17, 2012. In the interim, discovery is ongoing.

We believe that these legal theories advanced by the codefendant should not be applied against GlobalSantaFe or Transocean Worldwide Inc. Our subsidiary, its parent and GlobalSantaFe intend to continue to vigorously defend against any action taken in an attempt to impose liability against them under the theories discussed above or otherwise and believe they have good and valid defenses thereto. We do not believe that these claims will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

We have included the following information, presented as of February 22, 2012, 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 22, 2012
Steven L. Newman	President and Chief Executive Officer	47
Gregory L. Cauthen	Executive Vice President and Chief Financial Officer	54
Nick Deeming	Senior Vice President, General Counsel and Assistant Corporate Secretary	57
Ihab Toma	Executive Vice President, Operations	49

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 in 1989 from the Colorado School of Mines and his MBA in 1992 from the Harvard University Graduate School of Business. Mr. Newman is also a member of the Society of Petroleum Engineers.

Gregory L. Cauthen is the Company's interim Executive Vice President and Chief Financial Officer under an employment agreement through June 2012. Mr. Cauthen also assumed the responsibilities of Principal Accounting Officer in January 2012. Mr. Cauthen served as a consultant to the Company from September 2009 to August 2010. Since August 2010, Mr. Cauthen has pursued personal interests. Prior to his retirement in August 2009, Mr. Cauthen was Chief Financial Officer of the Company from December 2001 to August 2009. He was also Treasurer of the Company from March 2001 until July 2003 and served as Vice President, Finance from March 2001 to December 2001. Mr. Cauthen holds a Masters in Accounting degree from the University of Florida, Gainesville.

Nick Deeming is Senior Vice President, General Counsel and Assistant Corporate Secretary of the Company. Before being named to this position in February 2011, Mr. Deeming most recently served as Group General Counsel and Company Secretary of Christie's International Plc, from 2007 to 2010. Prior to Christie's, from 2001 to 2007, Mr. Deeming served as Chief Legal Officer of Linde Group AG, formerly BOC Group Plc. He served as the Chief Legal Officer of Sema Group Plc from 1999 to 2001; the Group Legal Director of PPP Healthcare Group Plc from 1990 to 1998, Group Legal Director of the financial services company Target Group Plc from 1986 to 1990, and Head of Legal Services of Burmah Oil Exploration from 1983 to 1986. Mr. Deeming received his law degree in 1977 from Guildhall University, subsequently qualified as a solicitor in 1981 and received his MBA in 1996 from Cranfield University.

Ihab Toma is Executive Vice President, Operations of the Company. Before being named to his current position in August 2011, Mr. Toma served as Executive Vice President, Global Business of the Company from August 2010 to August 2011 and as Senior Vice President, Marketing and Planning of the Company 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 Oilfield Services from April 2006 to August 2009. Mr. Toma led Schlumberger's information solutions business in various capacities, including Vice President, Sales and Marketing, from 2004 to April 2006, prior to which he served in a variety of positions with Schlumberger Ltd., including President of Information Solutions, Vice President of Information Management and Vice President of Europe, Africa and CIS Operations. He started his career with Schlumberger in 1986. Mr. Toma received his Bachelor's degree in Electrical Engineering in 1985 from Cairo University.

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			
	2011		2010		2011		2010	
	High	Low	High	Low	High	Low	High	Low
First quarter	$ 85.98	$ 68.89	$ 94.88	$ 76.96	CHF 79.95	CHF 64.60	CHF —	CHF —
Second quarter	83.05	59.30	92.67	41.88	75.80	49.58	101.10	49.90
Third quarter	65.39	47.70	65.98	44.30	55.25	36.52	64.45	46.54
Fourth quarter	60.09	38.21	73.94	61.60	51.70	36.02	72.00	59.15

On February 22, 2012, the last reported sales price of our shares on the NYSE and the SIX was $48.99 per share and CHF 45.06 per share, respectively. On such date, there were 8,915 holders of record of our shares and 350,424,694 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 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.

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.

In December 2011, we completed a public offering of 29.9 million shares at a share price of $40.50, equivalent to CHF 37.19 using an exchange rate of $1.00 to CHF 0.9183. On December 5, 2011, we received proceeds from the offering of $1.2 billion, net of underwriting discounts and commissions, estimated issuance costs and the Swiss Federal Issuance Stamp Tax.

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 from 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, 2011, the aggregate amount of par value of our outstanding shares was CHF 5.5 billion, equivalent to $5.9 billion, and the aggregate amount of qualifying additional paid-in capital of our outstanding shares was at least CHF 9.8 billion, equivalent to at least $10.4 billion, at an exchange rate of $1.00 to CHF 0.94 on December 31, 2011. 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 of Publicly Announced Plans or Programs (2)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (2) (in millions)
October 2011	645	$ 46.76	—	$ 3,560
November 2011	14,286	50.36	—	3,560
December 2011	2,022	43.26	—	3,560
Total	16,953	$ 49.38	—	$ 3,560

(1) Total number of shares purchased in the fourth quarter of 2011 includes 16,953 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 $3.7 billion at an exchange rate as of the close of trading on December 31, 2011 of USD 1.00 to CHF 0.94). 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, 2011, we have repurchased a total of 2,863,267 of our shares under this share repurchase program at a total cost of $240 million ($83.74 per share). See "Part I. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Sources and Uses of Liquidity—Overview."

Item 6. Selected Financial Data

The selected financial data as of December 31, 2011 and 2010 and for each of the three years in the period ended December 31, 2011 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, 2009, 2008 and 2007, and for each of the two years in the period ended December 31, 2008 have been derived from our accounting records. The following data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements and the notes thereto included under "Item 8. Financial Statements and Supplementary Data."

	Years ended December 31,				
	2011 (a)	2010	2009	2008	2007 (b)
	(In millions, except per share data)				
Statement of operations data					
Operating revenues	$ 9,142	$ 9,466	$ 11,441	$ 12,462	$ 6,309
Operating income (loss)	(4,776)	1,857	4,390	5,298	3,207
Income (loss) from continuing operations	(5,829)	954	3,196	3,981	3,093
Net income (loss)	(5,632)	988	3,170	4,029	3,121
Net income (loss) attributable to controlling interest	(5,725)	961	3,181	4,031	3,121
Per share earnings (loss) from continuing operations					
Basic	$ (18.40)	$ 2.88	$ 9.95	$ 12.48	$ 14.44
Diluted	$ (18.40)	$ 2.88	$ 9.92	$ 12.38	$ 13.95
Balance sheet data (at end of period)					
Total assets	$ 35,088	$ 36,811	$ 36,436	$ 35,182	$ 34,356
Debt due within one year	2,039	2,012	1,868	664	6,172
Long-term debt	11,497	9,209	9,849	12,893	10,266
Total equity	15,691	21,375	20,559	17,167	13,382
Other financial data					
Cash provided by operating activities	$ 1,785	$ 3,946	$ 5,598	$ 4,959	$ 3,073
Cash used in investing activities	(1,896)	(721)	(2,694)	(2,196)	(5,677)
Cash provided by (used in) financing activities	734	(961)	(2,737)	(3,041)	3,378
Capital expenditures	1,020	1,391	3,041	2,184	1,377
Distributions of qualifying additional paid-in capital	763	—	—	—	—
Per share distributions of qualifying additional paid-in capital	$ 2.37	$ —	$ —	$ —	$ —

(a) In October 2011, we completed our acquisition of Aker Drilling ASA 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. In December 2011, we completed a public offering of 29.9 million shares for aggregate net proceeds of $1.2 billion.

(b) In November 2007, Transocean Inc., a wholly owned subsidiary and our former parent holding company, completed its merger with GlobalSantaFe Corporation (the "Merger") and applied the acquisition method of accounting for the Merger. The balance sheet data as of December 31, 2007 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, 2007 include approximately one month of operating results and cash flows for the combined company. Transocean Inc. financed payments made in connection with the Merger with borrowings under a $15.0 billion bridge loan facility.

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 "Item 1. Business," "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 14, 2012, we owned or had partial ownership interests in and operated 134 mobile offshore drilling units. As of this date, our fleet consisted of 50 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters, nine High-Specification Jackups, 49 Standard Jackups and one swamp barge. In addition, we had two Ultra-Deepwater Floater and four High-Specification Jackups under construction.

We have two reportable segments: (1) contract drilling services and (2) drilling management services, formerly a component of our other operations segment. 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, jackups and other rigs 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.

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 through Applied Drilling Technology Inc., our wholly owned subsidiary, and through ADT International, a division of one of our U.K. subsidiaries (together, "ADTI").

Significant Events

Business combination—In October 2011, we completed our acquisition of Aker Drilling ASA ("Aker Drilling"), a Norwegian company formerly listed on the Oslo Stock Exchange. In connection with the acquisition, we acquired two Harsh Environment, Ultra-Deepwater semisubmersibles currently operating on long-term contracts in Norway. Additionally, we acquired two Ultra-Deepwater drillships currently under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, which have expected deliveries in 2014. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Discontinued operations—In February 2011, we sold the subsidiary that owns the High-Specification Jackup *Trident 20*, located in the Caspian Sea. In March 2011, 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. and Challenger Minerals (North Sea) Limited (together, "CMI"). As a result of these actions, we reclassified to discontinued operations the operating results and the assets and liabilities associated with our Caspian Sea operations and our oil and gas operations. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited, and in February 2012, we entered into an agreement to sell the assets of Challenger Minerals Inc. See "—Results of Operations—Discontinued Operations."

Bank credit agreement—In November 2011, we entered into the Five-Year Revolving Credit Facility Agreement dated November 1, 2011, which established a $2.0 billion five-year revolving credit facility that is scheduled to expire on November 1, 2016 (the "Five-Year Revolving Credit Facility"). See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Debt issuance—In December 2011, we issued in a public offering $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"). We received net proceeds of $2.5 billion from this offering. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Debt repurchase—Holders of the 1.50% Series B Convertible Senior Notes due 2037 ("Series B Convertible Senior Notes") had the option to require Transocean Inc., our wholly owned subsidiary and the issuer of the Series B Convertible Senior Notes, to repurchase all or any part of such holder's notes on December 15, 2011. As a result, we were required to repurchase an aggregate principal amount of $1.7 billion of our Series B Convertible Senior Notes for an aggregate cash payment of $1.7 billion. On February 15, 2012, we redeemed the remaining $30 million of aggregate principal amount of our Series B Convertible Senior Notes for an aggregate cash payment of $30 million. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Share issuance—In December 2011, we completed a public offering of 29.9 million shares at a price per share of $40.50, equivalent to CHF 37.19 using an exchange rate of USD 1.00 to CHF 0.9183. We received net proceeds of $1.2 billion from this offering. 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 December 21, 2011, we paid the third installment to shareholders of record as of November 25, 2011. At February 22, 2012, the carrying amount of the unpaid distribution payable was $278 million. See "—Liquidity and Capital Resources—Sources and Uses of Liquidity."

Impairment of goodwill—As of October 1, 2011, we determined that the goodwill associated with our contract drilling services reporting unit was impaired, and we recognized an estimated loss on impairment of goodwill in the amount of $5.2 billion. See "—Results of Operations—Historical 2011 compared to 2010" and —Critical Accounting Policies and Estimates."

Contingent liability—In the three months ended December 31, 2011, we recognized an estimated loss of $1.0 billion, recorded in operating and maintenance expense, in connection with the loss contingencies associated with the Macondo well incident that we believe are probable and for which a reasonable estimate can be made. As of December 31, 2011, we have recognized a liability for estimated loss contingencies in the amount of $1.2 billion. See "—Results of Operations—Historical 2011 to compared to 2010", "—Contingencies—Macondo well incident" and "—Critical Accounting Policies and Estimates—Contingencies."

Outlook

Drilling market—We expect commodity pricing to remain at levels that continue to support the ongoing exploration and production programs of our customers, resulting in contracting opportunities for all classes within our drilling fleet for the remainder of 2012 and into 2013. Oil price stability and exploration success during 2010 and 2011 have prompted our customers to increase budgets for exploration and production. Utilization and dayrates are improving for most of the asset classes within our drilling fleet, and we expect this trend to continue over the next 18 months. As of February 14, 2012, our contract backlog was $21.4 billion compared to $23.5 billion as of October 17, 2011.

Following the Macondo well incident, the U.S. government implemented enhanced regulations related to offshore drilling in the U.S. Gulf of Mexico. In order to obtain new drilling permits and pursue drilling activities, operators must submit applications that demonstrate compliance with enhanced regulations that 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. In the first quarter of 2011, the U.S. government began issuing new drilling permits under these enhanced regulations. As of February 14, 2012, authorities approved 37 new drilling permits and 27 new exploration plans under these enhanced regulations to customers utilizing our rigs in the U.S. Gulf of Mexico. Some customers have also elected to voluntarily apply the requirement for third-party inspections and certification to well control equipment operating outside the U.S. Gulf of Mexico, and the application of and compliance with these enhanced requirements has caused and may continue to cause us to experience additional out of service time and incur additional maintenance costs. As a result of the enhanced requirements for third-party inspections and certification of well control equipment, we updated our guidelines under our existing periodic survey and drydock cost policy to include these new inspections and certification costs. Although the enhanced regulations have affected our revenues, costs and out of service time, we are unable to predict, with certainty, the ongoing effect that the enhanced regulations will have on our operations. The backlog associated with the contracts for our remaining rigs in the U.S. Gulf of Mexico was $5.8 billion as of February 14, 2012.

Fleet status—As of February 14, 2012, the uncommitted fleet rates for the remainder of 2012, 2013, 2014 and 2015 are as follows:

	Years ending December 31,			
	2012	2013	2014	2015
Uncommitted fleet rate (a)				
High-Specification Floaters	18%	37%	64%	79%
Midwater Floaters	43%	73%	84%	90%
High-Specification Jackups	24%	57%	69%	75%
Standard Jackups	45%	70%	84%	97%

(a) The uncommitted fleet rate is the number of uncommitted days as a percentage of the total number of available rig calendar days in the period.

As of February 14, 2012, we had 17 existing contracts with 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 expect that a number of these options will not be exercised by our customers in 2012. 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 four remaining Ultra-Deepwater Floaters with availability in 2012. During the fourth quarter 2011, 13 Ultra-Deepwater Floaters were contracted worldwide, and we expect continued customer demand to support high utilization of our Ultra-Deepwater Floater fleet in 2012 and 2013. Additionally, we expect increased demand for Deepwater Floaters to continue to improve in 2012, recently indicated by two new contracts and a contract extension for our Deepwater Floaters. Through our acquisition of Aker Drilling in October 2011, we have enhanced our High-Specification Floater fleet with the addition of two Harsh Environment, Ultra-Deepwater semisubmersible drilling rigs operating under long-term contracts in Norway and two Ultra-Deepwater drillships under construction with expected deliveries in 2014. As of February 14, 2012, we had 36 of our 50 High-Specification Floaters contracted through the end of 2012. 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.

Midwater Floaters—For our Midwater Floater fleet, which includes 25 semisubmersible rigs, customer interest has increased with multiple customers interested in available rigs, and we expect to see increased activity in Southeast Asia, the U.K., West Africa and India. We have entered into eight contracts for our Midwater Floater fleet in the fourth quarter of 2011. Although many of the contracts are for short-term work, we also entered into a long-term contract for one unit in India. We believe that future demand will offer new opportunities to extend our active fleet. With the improvement in market conditions, we expect that moored Deepwater Floaters previously competing in the midwater market sector will now be contracted for deepwater opportunities.

High-Specification Jackups—The High-Specification Jackup fleet continues to attract the interest of our customers, evidenced by increased tendering activity that we expect to continue to improve during 2012. As a result, we expect utilization to remain high during this period. We recently entered into one three-year contract for our BMC400 design, High-Specification Jackup *Transocean Honor* in Angola, currently under construction with operations expected to commence in the first quarter of 2012. As of February 14, 2012, we had one of our existing nine High-Specification Jackups available.

Standard Jackups—With increased tendering activity and high utilization in the high-specification jackup market sector, customers are now showing increased interest in the Standard Jackups, resulting in expected improvements in utilization and opportunities to reactivate some of the idle capacity. We expect this trend to continue through 2012, resulting in new opportunities for our Standard Jackups. We recently reactivated one jackup for a three-year contract in Saudi Arabia. As of February 14, 2012, we had 19 of our 49 Standard Jackups stacked, excluding one that was held for sale. In 2012, we expect increasing demand to provide opportunities to extend our available fleet and to reactivate a few of our Standard Jackups that require minimal reactivation costs.

Operating results—We expect our total revenues for the year ending December 31, 2012 to be higher than our total revenues for the year ended December 31, 2011, primarily due to fewer expected out of service and idle days, increased activity produced by the addition of two Harsh Environment, Ultra-Deepwater semisubmersibles acquired in the Aker Drilling acquisition, and the commencement of operations of our newbuild units delivered in 2011 and to be delivered in 2012. We are unable to predict, with certainty, the full impact that the enhanced regulations, described under "—Drilling market", will have on our operations in 2012 and beyond.

We expect our total operating and maintenance expenses for the year ending December 31, 2012 to be higher than our total operating and maintenance expenses for the year ended December 31, 2011, primarily due to increased operating costs resulting from the additional rigs acquired in the Aker Drilling acquisition and higher personnel costs resulting from increased salaries and increased drilling activity associated with our newbuild units delivered in 2011 and 2012. Our projected operating and maintenance expenses for the year ending December 31, 2012 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, as well as other factors.

Although we are unable to estimate the full direct and indirect impact 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 two years ended December 31, 2011, 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. In one case, the increased downtime has resulted in the recent termination of one of our contracts, which represented backlog of approximately $470 million. In the three months ended December 31, 2011, we recognized an estimated loss of $1.0 billion, recorded in operating and maintenance expense, 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 years ended December 31, 2011 and 2010, we incurred incremental costs, primarily associated with legal expenses for lawsuits and investigations, net of expected insurance recoveries, in the amount of $71 million and $139 million, respectively. Collectively, the lost contract backlog from the incident and from the recent termination, lost revenues and incremental expenses from extended shipyard projects and increased downtime, loss contingencies associated with the incident and other incremental costs have had an effect of greater than $3.0 billion. See "—Contingencies—Insurance matters" and "Part I., Item 1A. Risk Factors."

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, and we conduct impairment testing for our goodwill annually and when events and circumstances indicate that the fair value of a reporting unit may have fallen below its carrying amount. 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, and we recognized an estimated loss on impairment of goodwill in the amount of $5.2 billion. In the three months 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 for this asset group, and we recognized a loss on impairment of $1.0 billion (see "—Results of Operations" and "—Critical Accounting Policies and Estimates"). 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 further declines in actual or anticipated dayrates, especially with respect to our High-Specification Jackup fleet, we may be required to recognize additional losses in future periods as a result of an impairment of the carrying amount of one or more of our asset groups. We may be required to recognize additional losses on impairment of goodwill if we determine that the fair value of our contract drilling services reporting unit has declined below its carrying amount. At December 31, 2011, the carrying amount of our property and equipment was $22.5 billion, representing 64 percent of our total assets. The carrying amount of our goodwill was $3.2 billion, representing nine percent of our total assets after the effect of the impairment noted above. See "—Critical Accounting Policies and Estimates" and "Part I., Item 1A. Risk Factors."

Performance and Other Key Indicators

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

Contract backlog (a)	February 14, 2012	October 17, 2011	February 10, 2011
		(in millions)	
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 12,232	$ 14,070	$ 15,673
Deepwater Floaters	2,228	2,574	3,383
Harsh Environment Floaters	2,188	2,545	1,900
Total High-Specification Floaters	16,648	19,189	20,956
Midwater Floaters	2,249	2,140	1,912
High-Specification Jackups	1,051	914	129
Standard Jackups	1,434	1,213	936
Swamp Barge	24	30	47
Total	$ 21,406	$ 23,486	$ 23,980

(a) Contract backlog is calculated by multiplying the full contractual operating dayrate 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.

We acquired contract backlog of $901 million in connection with our acquisition of Aker Drilling, measured as of the acquisition date, October 3, 2011.

On December 31, 2011, two of our customers issued a joint notice to our Malaysian operating subsidiary terminating the *Deepwater Expedition* drilling contract on grounds of extensive downtime. At the time of the termination notice, the drilling contract represented approximately $470 million of our contract backlog.

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

At February 14, 2012, the contract backlog and average contractual dayrates for our contract drilling services segment were as follows:

	Total	2012	2013	2014	2015	Thereafter
		For the years ending December 31,				
Contract backlog (a)		(In millions, except average dayrates)				
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 12,232	$ 3,902	$ 3,526	$ 1,958	$ 872	$ 1,974
Deepwater Floaters	2,228	876	516	487	240	109
Harsh Environment Floaters	2,188	901	935	327	25	—
Total High-Specification Floaters	16,648	5,679	4,977	2,772	1,137	2,083
Midwater Floaters	2,249	1,218	588	255	133	55
High-Specification Jackups	1,051	255	175	206	164	251
Standard Jackups	1,434	702	455	226	51	—
Swamp Barge	24	24	—	—	—	—
Total contract backlog	$ 21,406	$ 7,878	$ 6,195	$ 3,459	$ 1,485	$ 2,389
Average contractual dayrates (b)						
High-Specification Floaters						
Ultra-Deepwater Floaters	$ 502,000	$ 506,000	$ 511,000	$ 520,000	$ 497,000	$ 470,000
Deepwater Floaters	$ 341,000	$ 347,000	$ 346,000	$ 341,000	$ 329,000	$ 302,000
Harsh Environment Floaters	$ 440,000	$ 432,000	$ 446,000	$ 402,000	$ 451,000	$ —
Total High-Specification Floaters	$ 464,000	$ 461,000	$ 474,000	$ 470,000	$ 449,000	$ 456,000
Midwater Floaters	$ 284,000	$ 290,000	$ 298,000	$ 258,000	$ 239,000	$ 264,000
High-Specification Jackups	$ 139,000	$ 138,000	$ 147,000	$ 141,000	$ 139,000	$ 135,000
Standard Jackups	$ 89,000	$ 92,000	$ 87,000	$ 84,000	$ 96,000	$ —
Swamp Barge	$ 73,000	$ 73,000	$ —	$ —	$ —	$ —
Total fleet average	$ 316,000	$ 299,000	$ 328,000	$ 303,000	$ 326,000	$ 361,000

(a) Contract backlog is calculated by multiplying the full contractual operating dayrate 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 contracted operating dayrate to be earned per revenue earning day in the period. A revenue earning 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, 2011	September 30, 2011	December 31, 2010
Average daily revenue (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 542,900	$ 524,800	$ 435,900
Deepwater Floaters	$ 351,600	$ 348,400	$ 395,600
Harsh Environment Floaters	$ 468,300	$ 433,800	$ 366,800
Total High-Specification Floaters	$ 486,600	$ 478,900	$ 414,500
Midwater Floaters	$ 274,300	$ 287,400	$ 298,500
High-Specification Jackups	$ 111,900	$ 115,600	$ 129,400
Standard Jackups	$ 93,400	$ 100,400	$ 110,600
Swamp Barge	$ 73,800	$ 73,800	$ 73,000
Total fleet average daily revenue	$ 295,400	$ 290,200	$ 276,900

(a) Average daily revenue is defined as contract drilling revenue earned per revenue earning day. A revenue earning 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 total fleet average daily revenue rises as we stack Midwater Floaters, High-Specification Jackups and Standard Jackups, since these rig types are typically contracted at lower dayrates compared to the High-Specification Floaters. We include newbuilds in the calculation when the rigs commence operations upon acceptance by the customer.

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

	Three months ended		
	December 31, 2011	September 30, 2011	December 31, 2010
Utilization (a)			
High-Specification Floaters			
Ultra-Deepwater Floaters	79%	79%	76%
Deepwater Floaters	50%	37%	58%
Harsh Environment Floaters	95%	95%	92%
Total High-Specification Floaters	72%	67%	71%
Midwater Floaters	55%	55%	68%
High-Specification Jackups	74%	69%	31%
Standard Jackups	51%	48%	46%
Swamp Barge	99%	100%	48%
Total fleet average utilization	61%	58%	58%

(a) Utilization is the total actual number of revenue earning days as a percentage of the total number of calendar days in the period.

Our utilization declines as a result of idle and stacked rigs 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.

Results of Operations

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	Years ended December 31, 2010	Change	% Change
	(In millions, except day amounts and percentages)			
Revenue earning days	28,020	31,348	(3,328)	(11)%
Utilization	57%	63%		n/m
Average daily revenue	$ 297,400	$ 283,500	$ 13,900	5%
Contract drilling revenues	$ 8,335	$ 8,888	$ (553)	(6)%
Contract drilling intangible revenues	45	98	(53)	(54)%
Other revenues	762	480	282	59%
	9,142	9,466	(324)	(3)%
Operating and maintenance expense	(6,956)	(5,074)	(1,882)	37%
Depreciation and amortization	(1,449)	(1,536)	87	(6)%
General and administrative expense	(288)	(246)	(42)	17%
Loss on impairment	(5,229)	(1,010)	(4,219)	n/m
Gain on disposal of assets, net	4	257	(253)	(98)%
Operating income (loss)	(4,776)	1,857	(6,633)	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	(81)	10	(91)	n/m
Income (loss) from continuing operations before income tax expense	(5,434)	1,290	(6,724)	n/m
Income tax expense	(395)	(336)	(59)	18%
Income (loss) from continuing operations	(5,829)	954	(6,783)	n/m
Income from discontinued operations, net of tax	197	34	163	n/m
Net income (loss)	(5,632)	988	(6,620)	n/m
Net income attributable to noncontrolling interest	93	27	66	n/m
Net income (loss) attributable to controlling interest	$ (5,725)	$ 961	$ (6,686)	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 $580 million of decreased contract drilling revenues due to reduced drilling activity associated with stacked or idle rigs, (b) approximately $550 million of decreased contract drilling revenues due to fewer revenue earning days as a result of shipyard, mobilization, maintenance, repair and equipment certification projects a significant portion of which was associated with the post-Macondo regulatory and operating environment, 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) $485 million of increased contract drilling revenues associated with our newbuild units that commenced operations in 2010 and 2011, (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 and (c) approximately $100 million of increased contract drilling revenues due to the inclusion of Aker Drilling's operations.

Contract drilling intangible revenues declined for the year ended December 31, 2011, compared to the year ended December 31, 2010, due to completion of the contracts with which they were associated. Contract drilling intangible revenues represent the amortization of the fair value of drilling contracts in effect at the time of our merger with GlobalSantaFe. We recognize contract drilling intangible revenues over the respective contract period using the straight-line method of amortization.

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 $280 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 $700 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 $240 million of increased costs and expenses associated with our drilling management services, (d) approximately $135 million of increased costs and expenses associated with our newbuild units that commenced operations during 2010 and 2011 and (e) approximately $40 million of increased costs and expenses due to increased activities resulting from the inclusion of Aker Drilling's operations. These increases were partially offset by (a) $130 million of decreased costs and expenses related to lower utilization resulting from additional stacked rigs, (b) 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, and (c) $70 million of decreased costs and expenses related to insurance deductibles and legal costs associated with the Macondo well incident.

Depreciation and amortization decreased primarily due to the following: (a) $133 million of reduced depreciation expense associated with our Standard Jackup asset group, which was impaired in December 2010, (b) $46 million related to asset disposals completed in 2011 and (c) $3 million related to the loss of *Deepwater Horizon* in 2010. Partially offsetting the decrease was (a) $35 million of additional depreciation expense associated with two newbuild Ultra-Deepwater Floaters, which commenced operations in 2011, (b) $23 million related to one newbuild Ultra-Deepwater Floater, which commenced operations in late December 2010, (c) $11 million related to two rigs acquired in connection with our acquisition of Aker Drilling in October 2011 and (d) $26 million due to normal operations of our contract drilling services.

General and administrative expense increased primarily due to $21 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, and we recognized losses of $29 million on impairment primarily related to *GSF Britannia, George H. Galloway, GSF Labrador* and *Searex IV,* which were formerly classified as assets held for sale. For the year ended December 31, 2010, we determined that the Standard Jackups asset group in our contract drilling services reporting unit was impaired due to projected declines in dayrates and utilization for this asset group, and we recognized a loss on impairment of $1.0 billion. Additionally, we recognized losses on the impairment of the intangible assets associated with our drilling management services reporting unit in the aggregate amount of $55 million.

In the year ended December 31, 2010, we recognized a net gain on disposal of assets of $257 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 41.3 percent and 14.2 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, costs 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 $28 million and $38 million, respectively. These discrete tax items, coupled with the excluded income and expense items noted above, resulted in effective tax rates of (7.3) percent and 26.1 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 41.3 percent from 14.2 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.

Historical 2010 compared to 2009

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, 2010	Years ended December 31, 2009	Change	% Change
	(In millions, except day amounts and percentages)			
Revenue earning days	31,348	39,391	(8,043)	(20)%
Utilization	63%	79%	n/a	n/m
Average daily revenue	$ 283,500	$ 274,100	$ 9,400	3%
Contract drilling revenues	$ 8,888	$ 10,522	$ (1,634)	(16)%
Contract drilling intangible revenues	98	281	(183)	(65)%
Other revenues	480	638	(158)	(25)%
	9,466	11,441	(1,975)	(17)%
Operating and maintenance expense	(5,074)	(5,066)	(8)	n/m
Depreciation and amortization	(1,536)	(1,433)	(103)	7%
General and administrative expense	(246)	(209)	(37)	18%
Loss on impairment	(1,010)	(334)	(676)	n/m
Gain (loss) on disposal of assets, net	257	(9)	266	n/m
Operating income	1,857	4,390	(2,533)	(58)%
Other income (expense), net				
Interest income	23	5	18	n/m
Interest expense, net of amounts capitalized	(567)	(484)	(83)	17%
Loss on retirement of debt	(33)	(29)	(4)	14%
Other, net	10	37	(27)	(73)%
Income from continuing operations before income tax expense	1,290	3,919	(2,629)	(67)%
Income tax expense	(336)	(723)	387	(54)%
Income from continuing operations	954	3,196	(2,242)	(70)%
Income (loss) from discontinued operations, net of tax	34	(26)	60	n/m
Net income	988	3,170	(2,182)	(69)%
Net income (loss) attributable to noncontrolling interest	27	(11)	38	n/m
Net income attributable to controlling interest	$ 961	$ 3,181	$ (2,220)	(70)%

"n/a" means not applicable.

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2010 compared to the year ended December 31, 2009 primarily due to the following: (a) approximately $1.4 billion due to reduced drilling activity, as a greater number of rigs were stacked or idle, (b) approximately $525 million due to higher out-of-service time for shipyard, mobilization, maintenance and repair projects, (c) approximately $305 million due to special standby rates in effect during and subsequent to the U.S. Gulf of Mexico drilling moratorium and (d) approximately $120 million from the lost revenues associated with the *Deepwater Horizon* contract. These decreases in revenues were partially offset by increased revenues of approximately $890 million associated with our newbuilds that commenced operations during 2009 and 2010.

Contract drilling intangible revenues declined for the year ended December 31, 2010, compared to the year ended December 31, 2009, due to completion of the contracts with which they were associated. Contract drilling intangible revenues represent the amortization of the fair value of drilling contracts in effect at the time of our merger with GlobalSantaFe. We recognize contract drilling intangible revenues over the respective contract period using the straight-line method of amortization.

Other revenues decreased for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to reduced integrated services activity of $127 million and lower reimbursable revenues of $39 million. These reductions were partially offset by increased revenues of approximately $22 million associated with our drilling management services.

Costs and expenses—Operating and maintenance expenses decreased for the year ended December 31, 2010 compared to the year ended December 31, 2009 as follows: (a) approximately $400 million resulting from lower utilization, (b) approximately $110 million due to reduced litigation settlement expense, (c) approximately $105 million due to reduced activities in our integrated services operations and (d) approximately $40 million related to the sale of our ownership interest in two rigs. These reductions were partially offset by $260 million of expenses resulting from our newbuilds that commenced operations during 2009 and 2010, approximately $225 million of expense due to increased shipyard and maintenance projects and $137 million of costs associated with the Macondo well incident, net of insurance recoveries.

Depreciation and amortization increased primarily due to $84 million of additional expense related to the commencement of operations of five newbuilds in late 2009, $32 million related to the commencement of operations of four newbuilds in 2010, and $16 million due to normal operations of our contract drilling services. Partially offsetting the increase was $20 million of reduced depreciation related to the extension of useful lives of five rigs in 2010 and $6 million related to the loss of *Deepwater Horizon*.

In the year ended December 31, 2010, we determined that the Standard Jackups asset group in our contract drilling services reporting unit was impaired due to projected declines in dayrates and utilization for this asset group, and we recognized a loss on impairment of $1.0 billion. During the year ended December 31, 2009, *GSF Arctic II* and *GSF Arctic IV*, both previously classified as assets held for sale, were impaired due to the global economic downturn and pressure on commodity prices, both of which had an adverse effect on our industry, and we recognized a loss on impairment of $279 million. Additionally, during the year ended December 31, 2009, we recognized losses on the impairment of the intangible assets associated with our drilling management services reporting unit in the aggregate amount of $55 million.

During the year ended December 31, 2010, we recognized a net gain on disposal of assets of $257 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*. During the year ended December 31, 2009, we recognized a net loss of $9 million related to sales of rigs and other property and equipment.

Other income and expense—Interest expense increased in the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to a $93 million reduction in interest capitalized for our newbuild projects, $33 million of increased interest expense associated with the *Petrobras 10000* capital lease and $33 million of increased interest expense associated with additional borrowings and debt issued subsequent to December 31, 2009. Partially offsetting these increases was $76 million associated with debt repaid or repurchased subsequent to 2009.

In the year ended December 31, 2010, we recognized losses on retirement of debt of $35 million primarily related to repurchases of the Series B Convertible Senior Notes and Series C Convertible Senior Notes and recognized a gain on debt retirement of $2 million related to the termination of the *GSF Explorer* capital lease obligation. In the year ended December 31, 2009, we recognized a loss on retirement of debt of $29 million primarily related to repurchases of the Series A Convertible Senior Notes.

Income tax expense—We operate internationally and provide for income taxes based on the tax laws and rates in the countries in which we operate and earn income. The annual effective tax rates were 14.2 percent and 16.6 percent at December 31, 2010 and 2009, respectively, based on income from continuing operations before income taxes, after excluding certain items, such as losses on impairment, net gains on certain disposals of assets, costs for litigation matters, and the gain resulting from insurance recoveries on the loss of *Deepwater Horizon*. 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, 2010 and 2009, the impact of the various discrete period tax items was a net tax expense of $38 million and a net tax benefit of $1 million, respectively. These discrete tax items, coupled with the excluded income and expense items noted above, resulted in effective tax rates of 26.1 percent and 18.5 percent on income from continuing operations before income tax expense for the years ended December 31, 2010 and 2009, 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 14.2 percent from 16.6 percent for the year ended December 31, 2010 compared to the year ended December 31, 2009 primarily due to the change in rig movement between taxing jurisdictions and decrease in U.S. operations due to the U.S. Gulf of Mexico drilling moratorium. With respect to the annual effective tax rate calculation for the year ended December 31, 2010, 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 and Nigeria. 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., Trinidad, 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

Oil and gas properties—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, a component of our other operations segment, which comprises the exploration, development and production activities performed by Challenger Minerals Inc. and Challenger Minerals (North Sea) Limited, our wholly owned oil and gas subsidiaries. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited for aggregate net cash proceeds of $24 million and recognized a gain on the disposal of the discontinued operations of $12 million. Additionally, in February 2012, we entered into an agreement to sell the assets of Challenger Minerals Inc.

Caspian Sea operations—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 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.

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

Business Combination

We have included approximately three months of operating results of Aker Drilling in our consolidated results of operations. Our operating revenues include approximately $100 million of contract drilling revenues associated with the operations of Aker Drilling for the year ended December 31, 2011.

See Notes to Consolidated Financial Statements—Note 4—Business Combination.

Liquidity and Capital Resources

Sources and Uses of Cash

Our primary sources of cash during the year ended December 31, 2011 were our cash flows from operating activities, proceeds from the issuance of our shares and the 2011 Senior Notes in December 2011, asset sales and disposals of our discontinued operations. Our primary uses of cash were capital expenditures, primarily associated with our newbuild projects, repurchases and redemption of our Convertible Senior Notes, our acquisition of Aker Drilling and our distributions of qualifying additional paid-in capital to shareholders. At December 31, 2011, we had $4.0 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 $1.0 billion. As a result, this portion of cash is not generally available to us for other uses.

	Years ended December 31,		
	2011	2010	Change
		(In millions)	
Cash flows from operating activities			
Net income (loss)	$ (5,632)	$ 988	$ (6,620)
Amortization of drilling contract intangibles	(45)	(98)	53
Depreciation and amortization	1,449	1,536	(87)
Loss on impairment	5,229	1,010	4,219
Gain on disposal of assets, net	(4)	(257)	253
Gain on disposal of discontinued operations, net	(181)	—	(181)
Other non-cash items	224	358	(134)
Changes in operating assets and liabilities, net	745	409	336
	$ 1,785	$ 3,946	$ (2,161)

Net cash provided by operating activities decreased primarily due to less cash generated from net income and an increase in working capital, after adjusting for non-cash items recognized during the year ended December 31, 2011 compared to the year ended December 31, 2010.

	Years ended December 31,		
	2011	2010	Change
		(In millions)	
Cash flows from investing activities			
Capital expenditures	$ (1,020)	$ (1,391)	$ 371
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	177	60	117
Proceeds from disposal of discontinued operations, net	284	—	284
Proceeds from insurance recoveries for loss of drilling unit	—	560	(560)
Other, net	(13)	50	(63)
	$ (1,896)	$ (721)	$ (1,175)

Net cash used in investing activities increased primarily due to our acquisition of Aker Drilling during the year ended December 31, 2011 and proceeds from insurance recoveries for the loss of *Deepwater Horizon* received during the year ended December 31, 2010 with no comparable activity during the year ended December 31, 2011. Partially offsetting this increase were the following: (a) reduced capital expenditures, as four of our High-Specification Jackups and two of our Ultra-Deepwater Floaters were under construction during the year ended December 31, 2011 compared to five of our Ultra-Deepwater Floaters that were under construction during the year ended December 31, 2010 and (b) proceeds from the sale of our discontinued operations, Challenger Minerals (North Sea) Limited and the operations of our Caspian Sea subsidiary, during the year ended December 31, 2011.

	Years ended December 31, 2011	2010	Change
		(In millions)	
Cash flows from financing activities			
Change in short-term borrowings, net	$ (88)	$ (193)	$ 105
Proceeds from debt	2,939	2,054	885
Repayments of debt	(2,409)	(2,565)	156
Proceeds from restricted cash investments	479	—	479
Deposits to restricted cash investments	(523)	—	(523)
Proceeds from share issuance, net	1,211	—	1,211
Distribution of qualifying additional paid-in capital	(763)	—	(763)
Purchases of shares held in treasury	—	(240)	240
Financing costs	(83)	(15)	(68)
Other, net	(29)	(2)	(27)
	$ 734	$ (961)	$ 1,695

Net cash provided by financing activities increased primarily due to increased proceeds from the issuance of debt, and the issuance of our shares in the year ended December 31, 2011 and reduced cash used to repay or repurchase debt during the year ended December 31, 2011 compared to the year ended December 31, 2010, and purchases of shares held in treasury in the year ended December 31, 2010 with no comparable activity in the year ended December 31, 2011. Partially offsetting this net reduction of cash used in financing activities was an increase in cash used for the payment of three installments of our distribution of qualifying additional paid-in capital in the year ended December 31, 2011 with no comparable activity during the year ended December 31, 2010.

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.

Capital expenditures, including capitalized interest of $39 million, totaled $1.0 billion during the year ended December 31, 2011, substantially all of which related to our contract drilling services segment. The following table presents the historical and projected capital expenditures and other capital additions, including capitalized interest, for our ongoing major construction projects conducted during the years ended December 31, 2010 and 2011 (in millions):

	Total costs through December 31, 2011	Expected costs for the year ending December 31, 2012	Estimated costs thereafter	Total estimated costs at completion
Deepwater Champion (a) (b)	$ 776	$ —	$ —	$ 776
Transocean Honor (c)	216	9	—	225
Ultra-Deepwater Floater TBN1 (d)	138	47	345	530
Ultra-Deepwater Floater TBN2 (d)	137	28	330	495
Transocean Siam Driller (e)	119	86	5	210
Transocean Andaman (e)	119	23	68	210
Transocean Ao Thai (f)	79	62	74	215
Capitalized interest	550	42	60	652
Mobilization costs	264	10	—	274
Total	$ 2,398	$ 307	$ 882	$ 3,587

(a) The accumulated construction costs of this rig are no longer included in construction work in progress, as the construction project has been completed as of December 31, 2011.

(b) The costs for *Deepwater Champion* include our initial investment of $109 million, representing the estimated fair value of the rig at the time of our merger with GlobalSantaFe in November 2007.

(c) In November 2010, we purchased *Transocean Honor*, a PPL Pacific Class 400 design jackup, which is under construction at PPL Shipyard Pte Ltd. in Singapore and is expected for delivery in the first quarter of 2012.

(d) The costs for Ultra-Deepwater Floater TBN1 and Ultra-Deepwater Floater TBN2 include our initial investment of $136 million and $136 million, respectively, representing the estimated fair value of the rigs at the time of our acquisition of Aker Drilling, completed in October 2011. The fair value of our initial investment is preliminary and is subject to change.

(e) In December 2010, we purchased *Transocean Siam Driller* and *Transocean Andaman,* two Keppel FELS Super B class design jackups, which are under construction at Keppel FELS' yard in Singapore and are expected for delivery in the first quarter of 2013.

(f) In June 2011, we purchased *Transocean Ao Thai,* a Keppel FELS Super B class design jackup, which is under construction at Keppel FELS' yard in Singapore and is expected for delivery in the third quarter of 2013.

For the year ending December 31, 2012, we expect capital expenditures to be approximately $1.3 billion, including approximately $307 million 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.

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."

We intend to fund the cash requirements relating to our capital expenditures through available cash balances, cash generated from operations and asset sales. We also have available credit under the Five-Year Revolving Credit Facility (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."

During the year ended December 31, 2011, in connection with our acquisition of Aker Drilling, we acquired two Harsh Environment, Ultra-Deepwater semisubmersibles, *Transocean Spitsbergen* and *Transocean Barents*, which are currently operating on long-term contracts in Norway. Additionally, in June 2011, we purchased the Keppel FELS Super B class design High-Specification Jackup *Transocean Ao Thai*, for $195 million. This High-Specification Jackup is under construction at Keppel FELS' yard in Singapore and is expected for delivery in the third quarter of 2013.

Dispositions—From time to time, we may review possible dispositions of drilling units. During the year ended December 31, 2011, in connection with our efforts to dispose of non-strategic assets, we sold the Standard Jackups, *Transocean Mercury*, *GSF Britannia*, *George H. Galloway, GSF Labrador* and *GSF Adriatic XI*, and the swamp barge, *Searex IV*, along with related equipment, and we received net aggregate proceeds of $163 million and recognized a net gain on the disposal of these assets of $19 million. During the year ended December 31, 2011, we recognized a net loss on disposal of other unrelated assets of $15 million.

Subsequent to December 31, 2011, we entered into agreements to sell the Standard Jackups, *GSF Rig 136*, *Transocean Nordic* and *Transocean Shelf Explorer*, and we reclassified to assets held for sale the rigs and related equipment, having an aggregate carrying amount of $59 million.

Unconsolidated affiliates—During the year ended December 31, 2011, we completed the sale of our 50 percent ownership interest in Overseas Drilling Limited, a Cayman Islands company, which owns the drillship *Joides Resolution*. In connection with the sale, we received net proceeds of $22 million and recognized a net gain of $13 million, recorded in other, net.

Sources and Uses of Liquidity

Overview—We expect to use existing cash balances, internally generated cash flows, borrowing 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, including the expected repurchase of any Series C Convertible Senior Notes that the noteholders may require us to repurchase in December 2012, capital expenditures, shareholder-approved distributions and working capital and other needs in our operations. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may continue to use a portion of our internally generated cash flows and proceeds from asset sales to reduce other 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 $1.0 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 lines of credit and under our commercial paper program 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 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. See "—Distribution of qualifying additional paid-in capital." In May 2009, our shareholders approved, and our board of directors subsequently authorized management to implement, a program 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 business on February 22, 2012 of USD 1.00 to CHF 0.91. See "—Share repurchase program."

On June 28, 2010, we received a letter from the U.S. Department of Justice ("DOJ") asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. We have engaged in discussions with the DOJ and have responded to their document requests, and we expect these discussions to continue. We can give no assurance that the DOJ investigation and other 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, potential liability related to the Macondo well incident, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. The economic downturn and related financial market instability, as well as uncertainty related to our potential liabilities from the Macondo well incident, have 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. The 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.

Debt issuance—In December 2011, we issued $1.0 billion aggregate principal amount of 5.05% Senior Notes, $1.2 billion aggregate principal amount of 6.375% Senior Notes and $300 million aggregate principal amount of 7.35% Senior Notes. We received aggregate net proceeds of $2.5 billion from this offering. The interest rates for the notes are subject to adjustment from time to time upon a change to the credit rating for the notes assigned by Moody's Investors Service or Standard & Poor's Ratings Services, up to a maximum increase of two percent. 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. 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 February 22, 2012, $1.0 billion, $1.2 billion and $300 million aggregate principal amount of the 5.05% Senior Notes, 6.375% Senior Notes and 7.35% Senior Notes, respectively, were outstanding.

Aker Revolving Credit and Term Loan Facility—In connection with our acquisition of Aker Drilling, we assumed the outstanding borrowings under a credit facility established by the Revolving Credit and Term Loan Facility Agreement dated February 21, 2011 (the "Aker Revolving Credit and Term Loan Facility"), comprised of a $500 million revolving credit facility and a $400 million term loan, which is secured by *Transocean Spitsbergen* and *Transocean Barents*. The Aker Revolving Credit and Term Loan Facility bears interest at the London Interbank Offered Rate ("LIBOR") plus a margin of 2.50 percent and mandatory costs, as defined, and requires scheduled quarterly installments on the term loan. The Aker Revolving Credit and Term Loan Facility expires in December 2015 and may be prepaid in whole or in part without premium or penalty. The Aker Revolving Credit and Term Loan Facility includes covenants requiring Aker Drilling, our wholly owned subsidiary, to maintain minimum liquidity, a maximum leverage ratio, a minimum interest coverage ratio, a minimum current ratio, and a minimum equity ratio, as defined. At February 22, 2012, $594 million was outstanding under the Aker Revolving Credit and Term Loan Facility at a weighted-average interest rate of 3.0 percent.

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. At February 22, 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 $166 million and $99 million, respectively, using an exchange rate of NOK 5.6549 to US $1.00. See Note 13—Derivatives and Hedging.

Eksportfinans Loans—In connection with our acquisition of Aker Drilling, we assumed the borrowings under the Loan Agreement dated September 12, 2008 ("Eksportfinans Loan A") and 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*. 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 February 22, 2012, $450 million and $450 million were outstanding under Eksportfinans Loan A and Eksportfinans Loan B, respectively.

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 22, 2012, the aggregate balance of the Aker Restricted Cash Investments was $900 million.

Share issuance—In December 2011, we completed a public offering of 29.9 million shares at a price of $40.50 per share, equivalent to CHF 37.19 using an exchange rate of $1.00 to CHF 0.9183. On December 5, 2011, we received proceeds of $1.2 billion, net of underwriting discounts and commissions, estimated issuance costs and the Swiss Federal Issuance Stamp Tax, from this offering.

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. In May 2011, we recognized a distribution payable, recorded in other current liabilities, with a corresponding entry to additional paid-in capital. 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. At February 22, 2012, the carrying amount of the unpaid distribution payable was $278 million.

Redeemable noncontrolling interest—Quantum owns the 50 percent interest in TPDI that is not owned by us. We present its interest in TPDI as redeemable noncontrolling interest on our consolidated balance sheets since Quantum has 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, subject to certain adjustments.

Bank credit agreement—In November 2011, we entered into the Five-Year Revolving Credit Facility Agreement dated November 1, 2011, which established a $2.0 billion five-year revolving credit facility that is scheduled to expire on November 1, 2016 (the "Five-Year Revolving Credit Facility"). In connection with entering into the Five-Year Revolving Credit Facility, we terminated our former five-year credit facility under the Five-Year Revolving Credit Agreement dated November 27, 2007. The Five-Year Revolving Credit Facility includes a $1.0 billion sublimit for the issuance of letters of credit, and all borrowings under the Five-Year Revolving Credit Facility are guaranteed by Transocean Ltd. 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. As of December 31, 2011, our debt to tangible capitalization ratio was 0.52 to 1.0. In order to borrow or have letters of credit issued under the Five-Year Revolving Credit Facility, we must, at the time of the borrowing request, not be in default under the bank credit agreement 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. Borrowings under the Five-Year Revolving Credit Facility 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. Our commitment fee and lending margin under the Five-Year Revolving Credit Facility are subject to change based on our credit rating. If our credit 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. A default under our public debt indentures could trigger a default under the Five-Year Revolving Credit Facility Agreement and, if not waived by the lenders, could cause us to lose access to the Five-Year Revolving Credit Facility and the commercial paper program for which it provides liquidity. At February 22, 2012, we had $24 million in letters of credit issued, we had $2.0 billion available borrowing capacity and we had no borrowings outstanding under the Five-Year Revolving Credit Facility.

Commercial paper program—We maintain a commercial paper program, which is supported by the Five-Year Revolving Credit Facility, under which we may issue privately placed, unsecured commercial paper notes up to a maximum aggregate outstanding amount of $1.5 billion. At February 22, 2012, we had no commercial paper outstanding.

TPDI Credit Facilities—TPDI has a bank credit agreement for a $1.265 billion secured credit facility (the "TPDI Credit Facilities"), comprised of a $1.0 billion senior term loan, a $190 million junior term loan and a $75 million revolving credit facility, which was established to finance the construction of and is secured by *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2.* One of our subsidiaries participates in the term loan with an aggregate commitment of $595 million. The senior term loan bears interest at a rate 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 rates of 2.25 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. 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. If Transocean Inc.'s long-term unsecured, unguaranteed and unsubordinated indebtedness is assigned a credit rating less than Baa3 or BBB- by Moody's Investor Service or Standard & Poor's Ratings Service, respectively, TPDI would be required to obtain insurance from a source other than our wholly owned captive insurance company within 10 business days.

At February 22, 2012, $945 million was outstanding under the TPDI Credit Facilities, of which $472 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on February 22, 2012 was 2.2 percent.

In April 2010, TPDI obtained a letter of credit in the amount of $60 million to satisfy its liquidity requirements under the TPDI Credit Facilities. The letter of credit was issued under an uncommitted credit facility that has been established by one of our subsidiaries. Additionally, TPDI is required to maintain certain cash balances in restricted accounts for the payment of the scheduled installments on the TPDI Credit Facilities. At February 22, 2012, TPDI had restricted cash investments of $2 million.

ADDCL Credit Facilities—ADDCL has a senior secured bank credit agreement for a credit facility (the "ADDCL Primary Loan Facility") comprised of Tranche A and Tranche C for $215 million and $399 million, respectively, which was established to finance the construction of and is secured by *Discoverer Luanda.* Unaffiliated financial institutions provide the commitment for and borrowings under Tranche A and one of our subsidiaries provides the commitment for Tranche C. 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 22, 2012, $190 million was outstanding under Tranche A at a weighted-average interest rate of 1.5 percent. At February 22, 2012, $399 million was outstanding under Tranche C, which was eliminated in consolidation.

Additionally, ADDCL has a secondary bank credit agreement for a $90 million credit facility (the "ADDCL Secondary Loan Facility"), for which one of our subsidiaries provides 65 percent of the total commitment. The facility bears interest at LIBOR plus the applicable margin, ranging from 3.125 percent to 5.125 percent, depending on certain milestones. 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. 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 the occurrence of a credit rating assignment of less than Baa3 or BBB- by Moody's Investors Service or Standard & Poor's Ratings Services, respectively, for Transocean Inc.'s long-term, unsecured, unguaranteed and unsubordinated indebtedness. In addition, upon such credit rating assignment, ADDCL would be required to obtain insurance from a source other than our wholly owned captive insurance company within 10 business days. At February 22, 2012, $79 million was outstanding under the ADDCL Secondary Loan

Facility, of which $51 million was provided by one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on February 22, 2012 was 3.7 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 22, 2012, ADDCL had restricted cash investments of $25 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 22, 2012, $676 million was outstanding under the capital lease contract.

Convertible Senior Notes—In December 2007, we issued $6.6 billion aggregate principal amount of Convertible Senior Notes. Our Convertible Senior Notes may be converted at a rate of 6.1902 shares per $1,000 note, equivalent to a conversion price of $161.55 per share. Upon conversion, we will 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 in excess of the aggregate principal amount of the notes being converted. The conversion rate is subject to increase upon the occurrence of certain fundamental changes and adjustment upon certain other corporate events, such as the distribution of cash to our shareholders.

Holders of the Series B Convertible Senior Notes had the option to require Transocean Inc., our wholly owned subsidiary and the issuer of the Convertible Senior Notes, to repurchase all or any part of such holders' notes in December 2011. As a result, in December 2011, we were required to repurchase an aggregate principal amount of $1.7 billion of our Series B Convertible Senior Notes for an aggregate cash payment of $1.7 billion. On February 22, 2012, we redeemed the remaining $30 million aggregate principal amount of our Series B Convertible Senior Notes for an aggregate cash payment of $30 million.

Holders of the Series C Convertible Senior Notes have the right to require us to repurchase their notes on December 14, 2012, 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. At February 22, 2012, $1.7 billion of the Series C Convertible Senior Notes remained outstanding.

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 22, 2012 of $1.00 to CHF 0.91. 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, 2010, we repurchased 2,863,267 of our shares under our share repurchase program for an aggregate purchase price of CHF 257 million, equivalent to $240 million. In the year ended December 31, 2011, 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 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 Swiss Exchange. 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 22, 2012, 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 3.2 billion shares, 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, 2011, our contractual obligations stated at face value, were as follows:

	For the years ending December 31,				
	Total	2012	2013 - 2014 (in millions)	2015 - 2016	Thereafter
Contractual obligations					
Debt (a)	$ 12,039	$ 1,984	$ 1,196	$ 2,977	$ 5,882
Debt of consolidated variable interest entities	838	97	197	356	188
Interest on debt (b)	6,587	638	1,164	1,045	3,740
Capital lease	1,273	66	144	145	918
Operating leases	239	39	66	43	91
Distribution of qualifying additional paid-in capital	278	278	—	—	—
Purchase obligations	1,311	311	1,000	—	—
Total (c)	$ 22,565	$ 3,413	$ 3,767	$ 4,566	$ 10,819

(a) Noteholders may, at their option, require Transocean Inc. to repurchase the Series C Convertible Senior Notes in December 2012, 2017, 2022, 2027 and 2032. In preparing the table above, we have assumed that the holders of our notes exercise the option at the first available date.

(b) Includes interest on consolidated debt.

(c) As of December 31, 2011, our defined benefit pension and other postretirement plans represented an aggregate liability of $640 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 14—Postemployment Benefit Plans.

As of December 31, 2011, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of $781 million. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in this balance, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities, and we have excluded this amount from the contractual obligations presented in the table above. See Notes to Consolidated Financial Statements—Note 6—Income Taxes.

Other commercial commitments—We have other commercial commitments that we are contractually obligated to fulfill with cash under certain circumstances. These commercial commitments include standby letters of credit and surety bonds that guarantee our performance as it relates to our drilling contracts, insurance, customs, tax and other obligations in various jurisdictions. Standby letters of credit are issued under a number of committed and uncommitted bank credit facilities. The obligations that are the subject of these standby letters of credit and surety bonds are geographically concentrated in Nigeria, India 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, 2011, these obligations stated in U.S. dollar equivalents and their time to expiration were as follows:

	For the years ending December 31,				
	Total	2012	2013 - 2014	2015 - 2016	Thereafter
			(in millions)		
Other commercial commitments					
Standby letters of credit	$ 650	$ 576	$ 54	$ 20	$ —
Surety bonds	12	12	—	—	—
Total	$ 662	$ 588	$ 54	$ 20	$ —

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, 2011, the cash investments held by the captive insurance company totaled $298 million, and the amount of such cash investments is expected to range from $250 million to $350 million by December 31, 2012. The amount of actual cash investments held by the captive insurance company varies, depending on the amount of premiums paid to the captive insurance company, the timing and amount of claims paid by the captive insurance company, and the amount of dividends paid by the captive insurance company.

Derivative Instruments

Our board of directors has approved policies and procedures for derivative instruments that require the approval of our Chief Financial Officer prior to entering into any derivative instruments. From time to time, we may enter into a variety of derivative instruments in connection with the management of our exposure to fluctuations in interest rates or foreign 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. In connection with our acquisition of Aker Drilling, we assumed certain derivative instruments that are not designated as hedging instruments. See Notes to Consolidated Financial Statements—Note 13—Derivatives and Hedging.

Retirement 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, primarily group pension schemes with life insurance companies, and two unfunded plans, covering our eligible Norway employees and former employees (the "Norway Plans"). In connection with our acquisition of Aker Drilling, we assumed the obligations under three funded defined benefit plans, under group pension schemes with life insurance companies, covering eligible Norway employees (the "Assumed 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, the Assumed 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, 2011				Year ended December 31, 2010			
	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)	$ 62	$ 25	$ 1	$ 88	$ 58	$ 31	$ 2	$ 91
Other comprehensive income	129	51	(1)	179	44	(56)	4	(8)
Employer contributions	70	29	4	103	69	45	4	118
At end of period:								
Accumulated benefit obligation	$ 1,083	$ 375	$ 53	$ 1,511	$ 921	$ 336	$ 56	$ 1,313
Projected benefit obligation	1,260	447	53	1,760	1,068	374	56	1,498
Fair value of plan assets	769	351	—	1,120	697	332	—	1,029
Funded status	(491)	(96)	(53)	(640)	(371)	(42)	(56)	(469)
Weighted-Average Assumptions								
-Net periodic benefit costs								
Discount rate (b)	5.49 %	5.73%	4.94%	5.53%	5.86%	5.67%	5.51%	5.80%
Long-term rate of return (c)	8.49 %	6.42%	n/a	7.83%	8.49%	6.65%	n/a	7.89%
Compensation trend rate (b)	4.24 %	4.62%	n/a	4.36%	4.21%	4.77%	n/a	4.37%
Health care cost trend rate-initial	n/a	n/a	8.08%	8.08%	n/a	n/a	8.00%	8.00%
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)	4.66 %	4.90%	4.28%	4.71%	5.48%	5.81%	4.92%	5.54%
Compensation trend rate (b)	4.22 %	4.30%	n/a	4.26%	4.24%	4.65%	n/a	4.36%

"n/a" means not applicable.

(a) Net periodic benefit costs were reduced by expected returns on plan assets of $86 million and $75 million for the years ended December 31, 2011 and 2010, 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 2018.

Net periodic benefit cost—In the year ended December 31, 2011, net periodic benefit costs decreased by $3 million primarily due to greater expected returns on plan assets, partially offset by higher interest costs. For the year ending December 31, 2012, we expect net periodic benefit costs to increase by $37 million compared to the net periodic benefit costs recognized in the year ended December 31, 2011 primarily due to the decline in interest rates during 2011 as well as unfavorable asset performance compared to expectations for 2011.

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. Plans, the plan trustees establish the asset allocation strategies consistent with the regulations of the U.K. pension regulators and in consultation with financial advisors and company representatives. Investment managers for the U.S. Plans and the U.K. Plan are given established ranges within which the investments may deviate from the target allocations. For the Norway Plans and the Assumed Norway Plans, we establish minimum returns under the terms of investment contracts with insurance companies.

In the year ended December 31, 2011, plan assets of the funded Transocean Plans were unfavorably impacted by a decline in world equity markets during 2011, given the allocation of approximately 58.4 percent of plan assets to equity securities. To a lesser extent, plan assets allocated to debt securities and other investments also experienced less than anticipated gains. In the year ended December 31, 2011, the fair value of the investments in the funded Transocean Plans increased by $91 million, or 8.8 percent, due to funding contributions, net of benefits paid out of the funded Transocean Plans of $49 million, investment gains of $31 million, and assets assumed in connection with our acquisition of Aker Drilling of $9 million.

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 and the Assumed 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.

For 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 ended December 31, 2010, we contributed $118 million and participants contributed $3 million to the Transocean Plans and the OPEB Plans.

For the year ending December 31, 2012, we expect to contribute $145 million to the Transocean Plans and $3 million to the OPEB Plans. These estimated contributions are comprised of $106 million to meet minimum funding requirements for the funded U.S. Plans, $31 million to meet the funding requirements for the funded non-U.S. Plans, and approximately $8 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,				
2012	$ 41	$ 10	$ 3	$ 54
2013	44	10	3	57
2014	47	10	3	60
2015	50	9	4	63
2016	54	9	4	67
2017-2021	319	62	20	401

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. The rig has been declared a total loss.

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. Our business has been negatively impacted by the loss of revenue from *Deepwater Horizon*. The backlog associated with the *Deepwater Horizon* drilling contract was approximately $590 million through the end of the contract term in 2013. We do not carry insurance for business interruption or loss of hire. In the two years ended December 31, 2011, 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. In one case, the increased downtime has resulted in the recent termination of one of our contracts, which represented backlog of approximately $470 million. In the three months ended December 31, 2011, we recognized an estimated loss of $1.0 billion, recorded in operating and maintenance expense, 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 years ended December 31, 2011 and 2010, we incurred incremental costs, primarily associated with legal expenses for lawsuits and investigations, net of expected insurance recoveries, in the amount of $71 million and $139 million, respectively. Collectively, the lost contract backlog from the incident and from the recent termination, lost revenues and incremental expenses from extended shipyard projects and increased downtime, loss contingencies associated with the incident and other incremental costs have had an effect of greater than $3.0 billion.

Trial is currently scheduled to commence involving us, BP and other defendants in the litigation arising out of the Macondo well incident before the MDL Court on March 5, 2012. There can be no assurance as to the outcome of the trial, that the trial will proceed according to the proposed schedule, 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 the trial, or as to the timing or terms of any such settlement.

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. As of December 31, 2011, we have recognized a liability for such loss contingencies in the amount of $1.2 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 not believe a reasonable estimate can be made. These contingencies could increase the liabilities we ultimately recognize. As of December 31, 2011, we have also recognized an asset of $220 million associated with the portion of our estimated losses that we believe is recoverable from insurance. Although we have available policy limits that could result in additional amounts recoverable from insurance, we are not currently able to estimate the amount of such additional recoverable amounts. Our estimates involve a significant amount of judgment. As a result of new information or future developments, some of which could occur very soon, 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. As of December 31, 2010, the amount of the estimated liability was $135 million, and the estimated recoverable amount was $94 million.

See "Part I., Item 3. Legal Proceedings—Macondo well incident."

Insurance coverage—We expect certain costs resulting from the Macondo well incident to be recoverable under insurance policies in effect at the time of the incident as described below.

Hull and machinery coverage—Deepwater Horizon had an insured value of $560 million, and there was no deductible for the total loss of the unit. During the year ended December 31, 2010, we received $560 million of cash proceeds from insurance recoveries for the loss of the drilling unit, and we recognized a gain on the disposal of the rig in the amount of $267 million. We also had coverage for costs incurred in our attempt to mitigate or minimize damage to *Deepwater Horizon* up to an amount equal to 25 percent of the rig's insured value, or $140 million. We also had coverage for wreck removal, which includes coverage for removal of diesel, for up to 25 percent of *Deepwater Horizon*'s insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our excess liability coverage described below, in the event wreck removal is required. As *Deepwater Horizon* was a total loss, there was no deductible for any applicable costs incurred to mitigate damages or for wreck removal, provided the costs are within the limits mentioned above.

Excess liability coverage—At the time of the Macondo well incident, we had $950 million of commercial market excess liability coverage, exclusive of deductibles and self-insured retention, noted below, which generally covered offshore risks such as personal injury, third-party property claims and third-party non-crew claims, including wreck removal and pollution. This $950 million excess liability limit was an annual aggregate limit, which covered the entire Transocean worldwide fleet, including *Deepwater Horizon*. Prior to the April 20, 2010 Macondo well incident, there were no known incidents or occurrences that would have eroded the $950 million aggregate excess liability limit for that period. We generally retained the risk for any liability losses with respect to the Macondo well incident and any other incidents or occurrences in excess of $1.0 billion. In the case of the Macondo well incident, we have paid $65 million in deductible costs prior to any insurance reimbursements from the excess liability insurance. We expect certain liability costs from the Macondo well incident in excess of the $65 million deductible and self-insured retention costs to be covered up to the $950 million excess liability limit.

In May 2010, we received notice from the operator under the drilling contract for *Deepwater Horizon* maintaining that it believes that it is entitled to additional insured status as provided for under the drilling contract. In response, many of our insurers filed declaratory judgment actions in the Houston Division of the U.S. District Court for the Southern District of Texas in May 2010, seeking a judgment declaring that they have limited additional-insured obligation to the operator. These actions have been transferred to the Multi-District Litigation Panel (the "MDL") for discovery purposes in the U.S. District Court, Eastern District of Louisiana. In the actions, our insurers maintain that, although the drilling contract requires additional insured protection for certain entities related to the operator, the protection is limited to the liabilities assumed by us under the terms of the drilling contract, which includes above land or water surface pollution emanating from substances in our possession, such as fuels, lubricants, motor oils, and bilge. Our insurers maintain that, under the drilling contract, the operator accepted full responsibility and indemnified us for any pollution not assumed by us. Further, our insurers contend that the liabilities the operator currently faces arise from pollution originating from the operator's well, below the surface and not within the scope of the additional insured protection.

Specifically, our insurers seek declarations that: (1) the operator assumed full responsibility in the drilling contract for any and all liabilities arising out of or in any way related to the release of oil originating from its well; (2) the additional insured status in the drilling contract therefore does not extend to the pollution liabilities the operator has incurred and will incur with respect to oil originating from its well; (3) our insurers have no additional obligation to the operator under any of the policies for the pollution liabilities it has incurred and will incur with respect to the oil originating from its well; and (4) the operator is not entitled to coverage under any of the policies for pollution liabilities it has incurred and will incur with respect to the oil originating from its well. The operator has filed a cross-claim, seeking contrary declarations.

On October 28, 2010, our insurer notified us that they have received letters from representatives of Anadarko and MOEX, each advising of its intent to preserve any rights to our insurance policies that it may have as an additional insured under the drilling contract. Any such claim, if paid to the operators, could limit the amount of coverage otherwise available to us. On November 15, 2011, the court ruled that coverage rights are limited to the scope of our indemnity of BP in the drilling contract. Proposed final judgments have been submitted to and are under consideration by the court. The court's ruling may be appealed.

Additionally, our first layer of excess insurers 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. A protocol has been executed by the parties to the suits, and claims have been submitted to the court for review. The parties to the interpleaders have agreed to a protocol to facilitate the reimbursement and funding of settlements of personal injury and fatality claims of our crew and vendors using insurance funds. To date, no payments have yet been received.

Other insurance—We also had $100 million of additional insurance that generally covered 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 provided coverage for such expenses in circumstances in which we have legal or contractual liability arising from our gross negligence or willful misconduct.

Limitation of liability action—At the instruction of our insurers and to preserve our insurance coverage, pursuant to the federal Limitation of a Shipowner's Liability Act (the "Limitation Act"), we filed a complaint in the Houston Division of the Southern District of Texas on May 13, 2010 regarding the casualty of the *Deepwater Horizon* rig. The action has been transferred to the U.S. District Court, Eastern District of Louisiana for further proceedings. Under the Limitation Act, a vessel owner is generally liable only for the post-accident value of the vessel and cargo as long as the vessel owner can show that it had no knowledge of or privity of knowledge with entities that were negligent. Claims limited under the Limitation Act include personal injury, wrongful death, and damage to property contained on the rig.

Pursuant to the Limitation Act, we are seeking an injunction staying certain lawsuits underway in jurisdictions other than the Eastern District of Louisiana. In addition, we are seeking to limit our liability for personal injury, wrongful death and damage to property contained on the rig to $27 million, the value of the rig and its freight, including the accounts receivable and accrued accounts receivable, as of April 28, 2010. One objective of the filing is to consolidate lawsuits relating to the *Deepwater Horizon* casualty and to process these lawsuits and claims in an orderly fashion, before a single federal judge. The filing also seeks to establish a single fund from which legitimate claims may be paid.

Investigations—As a result of the Macondo well incident, the Department of Homeland Security and the Department of Interior announced a joint investigation into the cause or causes of the incident and its effects. The U.S. Coast Guard and the Bureau of Ocean Energy Management, Regulation, and Enforcement (the "BOEMRE"), formerly the Minerals Management Service, share jurisdiction over the investigation into the incident and we participated in their hearings related to the incident. The final report was issued on September 14, 2011, and the Department of the Interior's Bureau of Safety and Environmental Enforcement ("BSEE") issued four notices of alleged non-compliance with regulatory requirements to us on October 12, 2011. Notices were also issued to Halliburton and BP. No fines have been issued though the citations could result in the assessment of civil penalties. We had sixty days to appeal these citations, but by agreement the appeal has been stayed pending a ruling in the MDL. In connection with the investigation, we received subpoenas from the Office of Inspector General of the Department of Interior for certain information. In addition, investigations have been commenced by the Chemical Safety Board, the National Academy of Engineering and the President of the United States has established the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (the "National Commission") to, among other things, examine the relevant facts and circumstances concerning the cause or causes of the Macondo well incident and develop options for guarding against future oil spills associated with offshore drilling. Additionally, we and some of the other companies that were involved in the Macondo well incident have conducted internal investigations into the incident. Many of these investigations have produced reports that are critical of us and our actions leading up to and in connection with the incident. Further, we participated in hearings related to the incident before various committees and subcommittees of the House of Representatives and the Senate of the United States, conferred with state and local government officials, and the DOJ has publicly announced that it has opened criminal and civil investigations of the Macondo well incident, which are described below. We cannot predict the ultimate outcome of these investigations, the total costs to be incurred in completing the investigations, the potential impact on personnel and the effect of implementing measures that may result from these investigations or to what extent, if any, we could be subject to fines, sanctions or other penalties.

U.S. Department of Justice—On June 28, 2010, we received a letter from the DOJ asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. We have engaged in discussions with the DOJ and have responded to their document requests, and we expect these discussions to continue. In addition, on December 15, 2010, the DOJ filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleges violations under the Oil Pollution Act of 1990 and the Clean Water Act, including claims for per barrel civil penalties of up to $1,100 per barrel or up to $4,300 per barrel if gross negligence or willful misconduct is established, and the DOJ reserved its rights to amend the complaint to add new claims and defendants. The U.S. government has estimated that up to 4.1 million barrels of oil were discharged and subject to penalties. The complaint asserts 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 the Oil Pollution Act of 1990 ("OPA"), and liable for civil penalties under the Clean Water Act, for all of the 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 January 9, 2012, we filed our opposition to the motion and filed a cross-motion for partial summary judgment seeking a ruling that we are not liable for the subsurface discharge of hydrocarbons. On February 22, 2012, the MDL Court ruled that we are not liable as a responsible party for damages under OPA with respect to the below surface discharges from the Macondo well. The 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 Clean Water Act, and that we therefore are not liable for such discharges as an owner of the vessel under the Clean Water Act. However, the court ruled that the issue of whether we could be held liable for such discharge under the Clean Water Act 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.

In addition to the civil complaint, the DOJ served us with Civil Investigative Demands ("CIDs") on December 8, 2010. These demands were part of an investigation by the DOJ to determine if we made false claims, or false statements in support of claims, in connection with the operator's acquisition of the leasehold interest in the Mississippi Canyon Block 252, Gulf of Mexico and drilling operations on *Deepwater Horizon.*

The DOJ is also conducting a criminal investigation into the Macondo well incident. On March 7, 2011, the DOJ announced the formation of a new task force to lead the criminal investigation. The task force served us with informal requests for documents in March 2011, and a grand jury issued a subpoena requesting documents from us on April 13, 2011. We have had a number of communications with the task force since that time, and the task force has made informal requests for additional information from us from time to time. The task force is investigating possible violations by us and certain unaffiliated parties of the Clean Water Act, the Migratory Bird Treaty Act, the Refuse Act, the Endangered Species Act, and the Seaman's Manslaughter Act, among other federal statutes.

Drilling moratorium and enhanced regulations—On May 30, 2010, the BOEMRE issued a notice to lessees and operators implementing a six-month moratorium on drilling activities with respect to new wells in water depths greater than 500 feet in the U.S. Gulf of Mexico. The notice also stated that the BOEMRE would not consider for the six-month moratorium period drilling permits for wells and related activities for those water depths. Subsequently, on June 22, 2010, a United States District Court in the Eastern District of Louisiana granted a preliminary injunction that effectively lifted the moratorium. On July 12, 2010, the U.S. Department of the Interior issued a revised moratorium that was scheduled to end on November 30, 2010 and that applied to deepwater drilling configurations and technologies rather than specific water depths. On October 12, 2010, the U.S. government lifted its moratorium. Following the lifting of the moratorium on October 12, 2010, operators are required to submit applications in order to obtain drilling permits and resume drilling activities that demonstrate compliance with enhanced regulations, which now 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. We are working in close consultation with our customers to comply with the new rules and requirements. Although the moratorium was lifted, its ongoing effects, and those of the enhanced regulations, have had and may continue to have a material adverse effect on our consolidated statement of financial position, results of operations, and cash flows. We are unable to estimate the full direct and indirect impact these factors will have on our business. The enhanced regulations have resulted in lost revenues and incremental costs associated with extended shipyard projects. See "—Outlook—Drilling market."

We can provide no assurances as to the estimated costs, insurance recoveries, or other actions that will result from the Macondo well incident. See "Part I., Item 1A. Risk Factors."

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, 2011, the insured value of our drilling rig fleet was approximately $36.4 billion, excluding our rigs under construction.

Hull and machinery—We completed the renewal of our hull and machinery insurance coverage, effective May 1, 2011, with updated rig insured values, primarily based on fair market value appraisals, and with similar terms as previous policies. Under the hull and machinery program, we generally maintain a $125 million per occurrence deductible, limited to a maximum of $250 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. However, we generally retain the risk for all hull and machinery exposures for our Standard Jackups and swamp barge, which are self-insured through our wholly-owned captive insurance company.

Excess liability coverage—We completed the renewal of our excess liability insurance coverage with some policies effective May 1, 2011. We carry $793 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 crew personal injury liability and on collision liability claims and (2) a separate $5 million per occurrence deductible 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, along with $157 million of the excess liability coverage, of which we have re-insured $25 million in the commercial market. In addition, we generally retain the risk for any liability losses in excess of $1.0 billion.

Other insurance—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 and CMI. 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 physical damage losses, including liability for wreck removal expenses, to our fleet caused by named windstorms in the U.S. Gulf of Mexico and war perils worldwide. Except with respect to *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*, we generally do not carry insurance for loss of revenue unless contractually required.

See Notes to Consolidated Financial Statements Note 15—Commitments and Contingencies—Retained risk and "Part I., Item 1A. Risk Factors."

Tax matters

We are a Swiss corporation and we operate through our various subsidiaries in a number of countries throughout the world. Our tax provision is based upon and subject to changes in the tax laws, regulations and treaties in effect in and between the countries in which our operations are conducted and income is earned. Our effective tax rate for financial reporting purposes fluctuates from year to year considering, among other factors, (a) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (b) rig movements between taxing jurisdictions and (c) our rig operating structures. A change in the tax laws, treaties or regulations in any of the countries in which we operate, or in which we are incorporated or resident, could result in a higher or lower effective tax rate on our worldwide earnings and, as a result, could have a material effect on our financial results.

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. On January 12, 2012, a judge in the U.S. Tax Court entered a decision of no deficiency for tax year 2004 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, except a claim regarding transfer pricing from certain charters of drilling rigs between our subsidiaries, reducing the total proposed adjustment to approximately $50 million, exclusive of interest. We believe an unfavorable outcome on this assessment with respect to 2005 activities would not result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. If the authorities were to continue to pursue this transfer pricing position with respect to subsequent years and were successful in such assertion, our effective tax rate on worldwide earnings with respect to the years following 2005 could increase substantially, and our earnings and cash flows from operations could be materially and adversely affected. As discussed below, the authorities have raised this transfer pricing issue with respect to our U.S. federal income tax returns for the years 2006 through 2008. Although we believe the transfer pricing for these charters is materially correct, we have been unable to reach a resolution with the tax authorities.

In May 2010, we received an assessment from the U.S. tax authorities related to our 2006 and 2007 U.S. federal income tax returns. In July 2010, we filed a protest letter with the U.S. tax authorities responding to this assessment. 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. These two items would result in net adjustments of approximately $278 million of additional taxes, exclusive of interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Furthermore, if the authorities were to continue to pursue these positions with respect to subsequent years and were successful in such assertions, our effective tax rate on worldwide earnings with respect to years following 2007 could increase substantially, and our earnings and cash flows from operations could be materially and adversely affected. We believe our returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims.

In addition, the May 2010 assessment included adjustments related to a series of restructuring transactions that occurred between 2001 and 2004. These restructuring transactions affected our basis in our former subsidiary TODCO, which we disposed of in 2004 and 2005. The authorities are disputing the amount of capital losses resulting from the disposition of TODCO. We utilized a portion of the capital losses to offset capital gains on our U.S. federal income tax returns for the years 2006 through 2009. The majority of the capital losses were unutilized and expired on December 31, 2009. The adjustments would also impact the amount of certain net operating losses and other carryovers into 2006 and later years. The authorities are also contesting the characterization of certain amounts of income received in 2006 and 2007 as capital gain and thus the availability of the capital gain for offset by the capital loss. These claims, with respect to our U.S. federal income tax returns for the years 2006 through 2009, could result in net tax adjustments of approximately $295 million. An unfavorable outcome on these potential adjustments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

The May 2010 assessment also included certain claims with respect to withholding taxes and certain other items resulting in net tax adjustments of approximately $160 million, exclusive of interest. In addition, the tax authorities assessed penalties associated with the various tax adjustments in the aggregate amount of approximately $88 million, exclusive of interest. We believe that our U.S. federal tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

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. These items would result in net adjustments of approximately $473 million of additional taxes, excluding interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Furthermore, if the authorities were to continue to pursue these positions with respect to subsequent years and were successful in such assertions, our effective tax rate on worldwide earnings with respect to years following 2009 could increase substantially, and could have a material adverse effect on our consolidated results of operations and cash flows. We believe our returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims.

Norway tax investigations—Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 2001 and 2002 as well as the actions of certain employees of our former external advisors on these transactions. The authorities issued tax assessments of approximately $262 million, plus interest, related to certain restructuring transactions, approximately $115 million, plus interest, related to the migration of a subsidiary that was previously subject to tax in Norway, approximately $69 million, plus interest, related to a 2001 dividend payment, and approximately $7 million, plus interest, related to certain foreign exchange deductions and dividend withholding tax. We have filed or expect to file appeals to these tax assessments. With respect to the tax assessment related to the migration of a subsidiary, we have provided a guarantee in the amount of approximately $120 million, plus interest, while this dispute is addressed by the Norwegian courts. Furthermore, we may be required to provide some form of additional financial security, in an amount up to $776 million, including interest and penalties, for these assessed amounts as this dispute is appealed and addressed by the Norwegian courts. The authorities have indicated that they plan to seek penalties of 60 percent on most but not all matters. 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 has been scheduled for 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 these charges are without merit and do not alter our technical assessment of the underlying claims. We intend to vigorously contest any assertions by the Norwegian civil and criminal authorities in connection with the various transactions being investigated. An unfavorable outcome on the Norwegian civil and criminal tax matters could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate resolution of these matters 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. In January 2012, the Norwegian authorities supplemented the previously issued criminal indictments by issuing a financial claim of approximately $315 million, jointly and severally, against our two subsidiaries, the two external advisors and the external tax attorney. This compensation claim directly overlaps with an existing civil tax assessment and does not represent an incremental financial exposure to us. In February 2012, the authorities dropped the previously existing tax assessment.

Brazil tax investigations—Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. The Brazil tax authorities have issued tax assessments totaling $109 million, plus a 75 percent penalty in the amount of $82 million and interest through December 31, 2011 in the amount of $150 million. An unfavorable outcome on these assessments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. 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.

See Notes to Consolidated Financial Statements—Note 6—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. We are cooperating with OFAC with respect to resolution of the matter. We may incur significant legal fees and related expenses, and the investigations may involve management time. We cannot predict the ultimate outcome of their investigation, the total costs to be incurred in completing the investigation, the potential impact on personnel, the effect of implementing any further measures that may be necessary to ensure full compliance with applicable laws or to what extent, if at all, we could be subject to fines, sanctions or other penalties.

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. We have 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 are cooperating with OFAC and believe that all of our operations fully comply with applicable laws. Although we are unable to predict the outcome of any of these matters, we do not expect the liability, if any, resulting from these inquiries to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2011.

Related Party Transactions

Quantum Pacific Management Limited—We hold a 50 percent interest in TPDI, a consolidated British Virgin Islands joint venture company formed to own and operate *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. Quantum Pacific Management Limited, a Cypriot company and successor in interest to Pacific Drilling Limited ("Quantum"), holds the remaining 50 percent interest.

Effective October 18, 2010, Quantum has the unilateral right to exchange its interest in the joint venture for our shares or cash, at an amount based on an appraisal of the fair value of the drillships, subject to certain adjustments. In the event Quantum elects to receive our shares, the number of shares to be issued is determined after adjusting the appraised fair value of the drillships by a valuation multiple of 1.08 and Quantum may elect to receive shares on either a net basis considering the indebtedness of TPDI or on a gross basis, which requires Quantum to assume or repay such indebtedness. Quantum is restricted from transferring these shares prior to the earlier of the first anniversary of the closing date or fifteen months following notice of exercise by Quantum.

As of February 22, 2012, TPDI had outstanding promissory notes in the aggregate amount of $296 million, of which $148 million was due to Quantum and was included in long-term debt on our consolidated balance sheet.

Angco Cayman Limited—We hold a 65 percent interest in ADDCL, a consolidated Cayman Islands joint venture company formed to own and operate *Discoverer Luanda*. 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 the appraisal of the fair value of the drillship, subject to certain adjustments.

Overseas Drilling Limited— We held a 50 percent interest in ODL, an unconsolidated Cayman Islands joint venture company, which owns *Joides Resolution*, a coring drillship that was adapted for scientific research. Under a management services agreement with ODL, we provided certain operational and management services through the date of the sale of our interest. We earned $1 million and $2 million for these services in each of the years ended December 31, 2011 and 2010, respectively.

In July 2011, we completed the sale of our 50 percent ownership interest in ODL to Siem Offshore Inc., our former partner. In connection with the sale, we received net proceeds of $22 million and recognized a net gain of $13 million recorded in other, net.

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, 2011, the liability for estimated tax exposures in our jurisdictions of operation was approximately $781 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, 2011, the amount of indefinitely reinvested earnings was approximately $2.2 billion. Should we make a distribution from the unremitted earnings of these subsidiaries, we would be subject to taxes payable to various jurisdictions. We estimate taxes in the range of $150 million to $200 million would be payable upon distribution of all previously unremitted earnings at December 31, 2011.

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, 2009, 2010 and 2011.

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

Contingent liabilities—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 that we expect to be recovered through insurance.

As of December 31, 2011, we have recognized a liability of $1.2 billion, the majority of which is associated with the Macondo well 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. Actual results may differ from this estimate. As a result of new information or future developments, some of which could occur very soon, 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.

Business combination—In connection with our acquisition of 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 acquisition cost exceeded the fair value of the net assets. We estimated the fair values of the acquired assets and assumed liabilities as of the acquisition date, and our estimates continue to be subject to adjustment based on our final assessments of the fair values of property and equipment, intangible assets, liabilities and our evaluation of tax positions and contingencies. We will complete our final assessments of the fair values of the acquired assets and assumed liabilities and our final evaluations of uncertain tax positions and contingencies within one year of the acquisition date.

Our estimates of fair value of property and equipment were subjective based on the age and condition of rigs acquired and the determination of the remaining useful lives of the rigs. We estimated the fair values of rigs acquired based on input from a third-party broker, and values were appraised based on perceptions of potential buyers and sellers in the market, which generally renders a low trading volume of rigs in the secondary market. The valuation of a rig and our estimate of the remaining useful life can also vary based on the rig design, condition and particular equipment configuration. It can be difficult to determine the fair value based on the cyclicality of our business, demand for offshore drilling rigs in different markets and changes in economic conditions. See Notes to Consolidated Financial Statements—Note 4—Business Combination.

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.

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 of October 1, 2011, we conducted our annual impairment testing for goodwill, all of which was associated with our contract drilling services reporting unit. As a result of our annual impairment test, we determined that the goodwill was impaired due to a decline in projected cash flows and market valuations for this reporting unit, and we recognized our best estimate of the loss on impairment in the amount of $5.2 billion. We estimated the implied fair value of the goodwill, measured as of the impairment testing date, using a variety of valuation methods, including cost, income and market approaches. We have not completed the measurement of our goodwill impairment due to the complexities involved in determining the implied fair value of goodwill. Our estimate is, therefore, subject to adjustment. We expect to complete the measurement of our goodwill impairment in the three months ending March 31, 2012.

The carrying amount of goodwill was $3.2 billion, representing nine percent of our total assets, as of December 31, 2011. See Notes to Consolidated Financial Statements—Note 11—Goodwill and 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 $210 million. A hypothetical one-year decrease would cause an increase in our annual depreciation expense of approximately $333 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, High-Specification Jackups, and Standard 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.

In the three months 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 for this asset group, and we recognized a loss on impairment of $1.0 billion. 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 further declines in actual or anticipated dayrates, especially with respect to our High-Specification Jackup fleet, we may be required to recognize additional losses in future periods as a result of an impairment of the carrying amount of one or more of our asset groups.

The carrying amount of our property and equipment was $22.5 billion as of December 31, 2011, representing 64 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 valuation of assets that reduces year-to-year volatility. In applying this approach, we recognize investment gains or losses 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 $12 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 $23 million.

New Accounting Pronouncements

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to interest rate risk and currency exchange rate risk, primarily associated with our restricted cash investments, 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
	2012	2013	2014	2015	2016	Thereafter	Total	12/31/11
Restricted cash investments								
Fixed rate (NOK)	$ 142	$ 142	$ 142	$ 142	$ 143	$ 178	$ 889	$ 930
Average interest rate	4.15 %	4.15 %	4.15 %	4.15 %	4.15 %	4.15 %		
Debt								
Fixed rate (USD)	$ 1,769	$ 770	$ 22	$ 1,123	$ 1,025	$ 6,272	$ 10,981	$ 11,284
Average interest rate	1.56 %	5.23 %	7.76 %	5.01 %	5.12 %	6.78 %		
Fixed rate (NOK)	$ 142	$ 142	$ 142	$ 142	$ 237	$ 178	$ 983	$ 1,031
Average interest rate	4.15 %	4.15 %	4.15 %	4.15 %	6.87 %	4.15 %		
Variable rate (USD)	$ 90	$ 90	$ 71	$ 65	$ 277	$ —	$ 593	$ 593
Average interest rate	3.02 %	3.02 %	3.02 %	3.02 %	3.02 %	— %		
Variable rate (NOK)	$ —	$ —	$ —	$ —	$ 158	$ —	$ 158	$ 167
Average interest rate	— %	— %	— %	— %	10.33 %	— %		
Debt of consolidated variable interest entities								
Variable rate (USD)	$ 97	$ 98	$ 100	$ 323	$ 35	$ 185	$ 838	$ 838
Average interest rate	1.73 %	1.72 %	1.72 %	2.18 %	1.49 %	2.29 %		
Interest rate swaps								
Fixed to variable (USD)	$ —	$ 750	$ —	$ 650	$ —	$ —	$ 1,400	$ 31
Average pay rate	— %	3.69 %	— %	3.70 %	— %	— %		
Average receive rate	— %	5.17 %	— %	3.81 %	— %	— %		
Interest rate swaps of consolidated variable interest entities								
Variable to fixed (USD)	$ 70	$ 70	$ 70	$ 263	$ —	$ —	$ 473	$ (16)
Average pay rate	2.34 %	2.34 %	2.34 %	2.34 %	— %	— %		
Average receive rate	0.58 %	0.58 %	0.58 %	0.58 %	— %	— %		
Cross-currency swaps								
Receive NOK / pay USD	$ —	$ —	$ —	$ —	$ 102	$ —	$ 102	$ (7)
Average pay rate	— %	— %	— %	— %	8.93 %	— %		
Average receive rate	— %	— %	— %	— %	11.00 %	— %		

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

In preparing the scheduled maturities of our debt, we assumed the noteholders will exercise their option to require us to repurchase the 1.50% Series C Convertible Senior Notes in December 2012.

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 13—Derivatives and Hedging.

Interest Rate Risk

At December 31, 2011, the face value of our variable-rate debt was approximately $2.5 billion, which represented 19 percent of the face value of our total debt, including the effect of our hedging activities. At December 31, 2011, our variable-rate debt, excluding the effect of our hedging activities, primarily consisted of borrowings under the ADDCL Credit Facilities and the TPDI Credit Facilities. At December 31, 2010, the face value of our variable-rate debt was approximately $1.2 billion, which represented 11 percent of the face value of our total debt, including the effect of our hedging activities. Based upon variable-rate debt amounts outstanding as of December 31, 2011 and 2010, a hypothetical one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of approximately $25 million and $12 million, respectively.

The fair value of our debt was $13.9 billion and $11.5 billion at December 31, 2011 and 2010, respectively. The $2.4 billion increase was primarily due to the issuance of new senior notes in the amount of $2.5 billion and additional debt of $1.8 billion assumed in acquisition of Aker Drilling, partially offset by the repurchase of Series B Convertible Senior Notes in the amount of $1.7 billion during the year ended December 31, 2011.

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, 2011 and 2010, a hypothetical one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $40 million and $33 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 have 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.

In the year ended December 31, 2011, we were exposed to currency exchange risk in connection with our acquisition of Aker Drilling, a Norwegian company formerly listed on the Oslo Stock Exchange. We entered into a forward exchange contract which was not designated as and did not qualify for hedge accounting. The aggregate notional amount was to pay $1.1 billion in exchange for NOK 6.1 billion, representing an exchange rate of $1.00 to NOK 5.4005.

At December 31, 2011, we had NOK 6.8 billion aggregate principal amount of debt obligations, all of which were assumed in connection with our acquisition of Aker Drilling. Certain of these kroner-denominated debt instruments are secured by a corresponding amount of restricted cash investments that are also denominated in Norwegian kroner. Additionally, we have assumed certain cross-currency swaps, which have been designated as a cash flow hedge of certain bonds denominated in Norwegian kroner. After consideration of these hedging activities, we have approximately NOK 6.2 billion aggregate principal amount of debt obligations that are not hedged. Based on kroner-denominated debt instruments outstanding as of December 31, 2011, a hypothetical one percentage point change in the currency exchange rates would result in a corresponding change in annual interest expense of approximately $8 million.

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 13—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 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, 2011. 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 ("COSO"). 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.

On October 3, 2011, we completed our acquisition of Aker Drilling ASA ("Aker Drilling"). Due to the close proximity of the acquisition date to December 31, 2011, the date of the most recent financial statements, management has excluded Aker Drilling from its assessment of the effectiveness of the Company's internal control over financial reporting. Aker Drilling accounted for nine percent of the Company's total assets and liabilities, as of December 31, 2011, and one percent of the Company's revenues for the year then ended.

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, 2011, 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, 2011, 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.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Aker Drilling ASA, which is included in the 2011 consolidated financial statements of Transocean Ltd. and Subsidiaries and constituted nine percent of total assets and liabilities as of December 31, 2011 and one percent of revenues for the year then ended. Our audit of internal control over financial reporting of Transocean Ltd. and Subsidiaries also did not include an evaluation of the internal control over financial reporting of Aker Drilling ASA.

In our opinion, Transocean Ltd. and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We have also 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, 2011 and 2010, 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, 2011 of Transocean Ltd. and Subsidiaries and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2012

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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2012

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

	Years ended December 31,		
	2011	2010	2009
Operating revenues			
Contract drilling revenues	$ 8,335	$ 8,888	$ 10,522
Contract drilling intangible revenues	45	98	281
Other revenues	762	480	638
	9,142	9,466	11,441
Costs and expenses			
Operating and maintenance	6,956	5,074	5,066
Depreciation and amortization	1,449	1,536	1,433
General and administrative	288	246	209
	8,693	6,856	6,708
Loss on impairment	(5,229)	(1,010)	(334)
Gain (loss) on disposal of assets, net	4	257	(9)
Operating income (loss)	(4,776)	1,857	4,390
Other income (expense), net			
Interest income	44	23	5
Interest expense, net of amounts capitalized	(621)	(567)	(484)
Loss on retirement of debt	—	(33)	(29)
Other, net	(81)	10	37
	(658)	(567)	(471)
Income (loss) from continuing operations before income tax expense	(5,434)	1,290	3,919
Income tax expense	395	336	723
Income (loss) from continuing operations	(5,829)	954	3,196
Income (loss) from discontinued operations, net of tax	197	34	(26)
Net income (loss)	(5,632)	988	3,170
Net income (loss) attributable to noncontrolling interest	93	27	(11)
Net income (loss) attributable to controlling interest	$ (5,725)	$ 961	$ 3,181
Earnings per share-basic			
Earnings (loss) from continuing operations	$ (18.40)	$ 2.88	$ 9.95
Earnings (loss) from discontinued operations	0.61	0.11	(0.08)
Earnings (loss) per share	$ (17.79)	$ 2.99	$ 9.87
Earnings per share-diluted			
Earnings (loss) from continuing operations	$ (18.40)	$ 2.88	$ 9.92
Earnings (loss) from discontinued operations	0.61	0.11	(0.08)
Earnings (loss) per share	$ (17.79)	$ 2.99	$ 9.84
Weighted-average shares outstanding			
Basic	322	320	320
Diluted	322	320	321

See accompanying notes.

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

	Years ended December 31, 2011	2010	2009
Net income (loss)	$ (5,632)	$ 988	$ 3,170
Other comprehensive income (loss) before income taxes			
Unrecognized components of net periodic benefit costs	(204)	(8)	37
Unrecognized loss on derivative instruments	(13)	(29)	(2)
Unrecognized loss on marketable securities	(13)	—	—
Recognized components of net periodic benefit costs	25	16	24
Recognized loss on derivative instruments	11	12	6
Recognized loss on marketable securities	13	—	1
Other comprehensive income (loss) before income taxes	(181)	(9)	66
Income taxes related to other comprehensive income (loss)	13	(9)	24
Other comprehensive income (loss), net of income taxes	(168)	(18)	90
Total comprehensive income (loss)	(5,800)	970	3,260
Total comprehensive income (loss) attributable to noncontrolling interest	89	6	(6)
Total comprehensive income (loss) attributable to controlling interest	$ (5,889)	$ 964	$ 3,266

See accompanying notes.

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

	December 31, 2011	December 31, 2010
Assets		
Cash and cash equivalents	$ 4,017	$ 3,394
Accounts receivable, net		
Trade	2,049	1,653
Other	127	190
Materials and supplies, net	627	514
Deferred income taxes, net	142	115
Assets held for sale	26	—
Other current assets	621	329
Total current assets	7,609	6,195
Property and equipment	29,037	26,721
Property and equipment of consolidated variable interest entities	2,252	2,214
Less accumulated depreciation	8,760	7,616
Property and equipment, net	22,529	21,319
Goodwill	3,205	8,132
Other assets	1,745	1,165
Total assets	$ 35,088	$ 36,811
Liabilities and equity		
Accounts payable	$ 880	$ 832
Accrued income taxes	89	109
Debt due within one year	1,942	1,917
Debt of consolidated variable interest entities due within one year	97	95
Other current liabilities	2,350	883
Total current liabilities	5,358	3,836
Long-term debt	10,756	8,354
Long-term debt of consolidated variable interest entities	741	855
Deferred income taxes, net	523	575
Other long-term liabilities	1,903	1,791
Total long-term liabilities	13,923	11,575
Commitments and contingencies		
Redeemable noncontrolling interest	116	25
Shares, CHF 15.00 par value, 365,135,298 authorized, 167,617,649 conditionally authorized, 365,135,298 issued and 349,805,793 outstanding at December 31, 2011; and 335,235,298 authorized, 167,617,649 conditionally authorized, 335,235,298 issued and 319,080,678 outstanding at December 31, 2010	4,982	4,482
Additional paid-in capital	7,211	7,504
Treasury shares, at cost, 2,863,267 held at December 31, 2011 and 2010	(240)	(240)
Retained earnings	4,244	9,969
Accumulated other comprehensive loss	(496)	(332)
Total controlling interest shareholders' equity	15,701	21,383
Noncontrolling interest	(10)	(8)
Total equity	15,691	21,375
Total liabilities and equity	$ 35,088	$ 36,811

See accompanying notes.

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

	Years ended December 31,			Years ended December 31,		
	2011	2010	2009	2011	2010	2009
Shares	Shares			Amount		
Balance, beginning of period	319	321	319	$ 4,482	$ 4,472	$ 4,444
Issuance of shares	30	—	—	488	—	—
Issuance of shares under share-based compensation plans	1	1	2	12	10	28
Purchases of shares held in treasury	—	(3)	—	—	—	—
Balance, end of period	350	319	321	$ 4,982	$ 4,482	$ 4,472
Additional paid-in capital						
Balance, beginning of period				$ 7,504	$ 7,407	$ 7,313
Issuance of shares, net of issue costs				671	—	—
Share-based compensation				95	102	81
Issuance of shares under share-based compensation plans				(18)	(11)	7
Obligation for distribution of qualifying additional paid-in capital				(1,041)	—	—
Other, net				—	6	6
Balance, end of period				$ 7,211	$ 7,504	$ 7,407
Treasury shares, at cost						
Balance, beginning of period				$ (240)	$ —	$ —
Purchases of shares held in treasury				—	(240)	—
Balance, end of period				$ (240)	$ (240)	$ —
Retained earnings						
Balance, beginning of period				$ 9,969	$ 9,008	$ 5,827
Net income (loss) attributable to controlling interest				(5,725)	961	3,181
Balance, end of period				$ 4,244	$ 9,969	$ 9,008
Accumulated other comprehensive loss						
Balance, beginning of period				$ (332)	$ (335)	$ (420)
Other comprehensive income (loss) attributable to controlling interest				(164)	3	85
Balance, end of period				$ (496)	$ (332)	$ (335)
Total controlling interest shareholders' equity						
Balance, beginning of period				$ 21,383	$ 20,552	$ 17,164
Total comprehensive income (loss) attributable to controlling interest				(5,889)	964	3,266
Issuance of shares, net of issue costs				1,159	—	—
Share-based compensation				95	102	81
Issuance of shares under share-based compensation plans				(6)	(1)	35
Obligation for distribution of qualifying additional paid-in capital				(1,041)	—	—
Purchases of shares held in treasury				—	(240)	—
Other, net				—	6	6
Balance, end of period				$ 15,701	$ 21,383	$ 20,552
Noncontrolling interest						
Balance, beginning of period				$ (8)	$ 7	$ 3
Total comprehensive income (loss) attributable to noncontrolling interest				(2)	7	(6)
Reclassification of redeemable noncontrolling interest				—	(26)	—
Other, net				—	4	10
Balance, end of period				$ (10)	$ (8)	$ 7
Total equity						
Balance, beginning of period				$ 21,375	$ 20,559	$ 17,167
Total comprehensive income (loss)				(5,891)	971	3,260
Issuance of shares, net of issue costs				1,159	—	—
Share-based compensation				95	102	81
Issuance of shares under share-based compensation plans				(6)	(1)	35
Obligation for distribution of qualifying additional paid-in capital				(1,041)	—	—
Purchases of shares held in treasury				—	(240)	—
Other, net				—	(16)	16
Balance, end of period				$ 15,691	$ 21,375	$ 20,559

See accompanying notes.

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

	Years ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income (loss)	$ (5,632)	$ 988	$ 3,170
Adjustments to reconcile to net cash provided by operating activities:			
Amortization of drilling contract intangibles	(45)	(98)	(281)
Depreciation and amortization	1,449	1,536	1,433
Share-based compensation expense	95	102	81
Loss on impairment	5,229	1,010	334
(Gain) loss on disposal of assets, net	(4)	(257)	9
Gain on disposal of discontinued operations, net	(181)	—	—
Amortization of debt issue costs, discounts and premiums, net	125	189	209
Deferred income taxes	(31)	(114)	(15)
Other, net	112	55	93
Changes in deferred revenue, net	(16)	205	169
Changes in deferred expenses, net	(61)	(79)	(38)
Changes in operating assets and liabilities	745	409	434
Net cash provided by operating activities	1,785	3,946	5,598
Cash flows from investing activities			
Capital expenditures	(1,020)	(1,391)	(3,041)
Investment in business combination, net of cash acquired	(1,246)	—	—
Payment for settlement of forward exchange contract, net	(78)	—	—
Purchases of marketable securities	—	—	(269)
Proceeds from disposal of assets, net	177	60	18
Proceeds from disposal of discontinued operations, net	284	—	—
Proceeds from insurance recoveries for loss of drilling unit	—	560	—
Proceeds from sale of marketable securities	—	37	564
Other, net	(13)	13	34
Net cash used in investing activities	(1,896)	(721)	(2,694)
Cash flows from financing activities			
Changes in short-term borrowings, net	(88)	(193)	(382)
Proceeds from debt	2,939	2,054	514
Repayments of debt	(2,409)	(2,565)	(2,871)
Proceeds from restricted cash investments	479	—	—
Deposits to restricted cash investments	(523)	—	—
Proceeds from share issuance	1,211	—	—
Distribution of qualifying additional paid-in capital	(763)	—	—
Purchases of shares held in treasury	—	(240)	—
Financing costs	(83)	(15)	(2)
Other, net	(29)	(2)	4
Net cash provided by (used in) financing activities	734	(961)	(2,737)
Net increase in cash and cash equivalents	623	2,264	167
Cash and cash equivalents at beginning of period	3,394	1,130	963
Cash and cash equivalents at end of period	$ 4,017	$ 3,394	$ 1,130

See accompanying notes.

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, 2011, we owned or had partial ownership interests in and operated 135 mobile offshore drilling units. As of this date, our fleet consisted of 50 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 25 Midwater Floaters, nine High-Specification Jackups, 50 Standard Jackups and one swamp barge. In addition, we had two Ultra-Deepwater Floaters and four High-Specification Jackups under construction (see Note 10—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 U.K. subsidiaries (together, "ADTI"). ADTI conducts drilling management services primarily on either a dayrate or a completed-project, fixed-price (or "turnkey") basis.

In February 2011, we sold the subsidiary that owns the High-Specification Jackup *Trident 20*, located in the Caspian Sea. In March 2011, 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. and Challenger Minerals (North Sea) Limited (together, "CMI"). As a result of these actions, we reclassified to discontinued operations the operating results associated with our Caspian Sea operations and our oil and gas operations. Additionally, we reclassified the assets and liabilities of these components as held for sale. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited. See Note 7—Discontinued Operations and Note 28—Subsequent Events.

In October 2011, we completed our acquisition of Aker Drilling, a Norwegian company formerly listed on the Oslo Stock Exchange. In connection with the acquisition, we acquired two Harsh Environment, Ultra-Deepwater semisubmersibles currently operating on long-term contracts in Norway. Additionally, we acquired two Ultra-Deepwater drillships currently under construction at the Daewoo Shipbuilding & Marine Engineering Co. Ltd. shipyard in Korea, which have expected deliveries in 2014. See Note 4—Business Combination.

Note 2—Significant Accounting Policies

Accounting estimates—The preparation of financial statements in accordance with accounting principles generally accepted in the United States ("U.S.") requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates and assumptions, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, property and equipment, investments, notes receivable, goodwill and other intangible assets, income taxes, share-based compensation, defined benefit pension plans and other postretirement benefits and contingencies. 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 significant judgment for which there is little or no market data ("Level 3"). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Consolidation—We consolidate entities in which we have a majority voting interest and entities that meet the criteria for variable interest entities for which we are deemed to be the primary beneficiary for accounting purposes. We eliminate intercompany transactions and accounts in consolidation. We apply the equity method of accounting for investments in entities if we have the ability to exercise significant influence over an 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 investments in other entities if we do not have the ability to exercise significant influence over the unconsolidated affiliate. See Note 23—Variable Interest Entities.

We recognized equity in earnings of unconsolidated affiliates, recorded in other, net, on our consolidated statements of operations, in the amount of $18 million, $8 million and $6 million for the years ended December 31, 2011, 2010 and 2009, respectively. Our investments in and advances to unconsolidated affiliates, recorded in other assets, had carrying amounts of less than $1 million and $19 million at December 31, 2011 and 2010, respectively.

Business combination—In connection with our acquisition of 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, and our estimates are subject to adjustment based on our final assessments of the fair values of property and equipment, intangible assets, liabilities and our evaluation of tax positions and contingencies. We will complete our final assessments of the fair values of the acquired assets and assumed liabilities and our final evaluations of uncertain tax positions and contingencies within one year of the acquisition date. See Note 4—Business Combination.

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.

Contract drilling intangible revenues—In connection with our business combination with GlobalSantaFe Corporation in November 2007, we acquired drilling contracts for future contract drilling services. The terms of these contracts include all 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. We recognized contract drilling intangible revenues of $45 million, $98 million and $281 million in the years ended December 31, 2011, 2010 and 2009, respectively. See Note 11—Goodwill and Other Intangible Assets.

Other revenues—Our other revenues represent those derived from drilling management services, integrated 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 anticipated. We refer to integrated services as those services we provide through contractors and our employees under certain contracts that include well and logistics services in addition to our normal drilling services. 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. Share-based compensation expense is recognized, net of a forfeiture rate, estimated at the time of grant based on historical experience and adjusted, if necessary, in subsequent periods based on actual forfeitures.

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 (“SARs”) 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 model and an average price at the performance start date. The risk neutral model 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. Share-based compensation expense was $95 million, $102 million and $81 million in the years ended December 31, 2011, 2010 and 2009, respectively. Income tax benefit on share-based compensation expense was $16 million, $13 million, and $11 million in the years ended December 31, 2011, 2010 and 2009, respectively. See Note 18—Share-Based Compensation Plans.

Capitalized interest—We capitalize interest costs for qualifying construction and upgrade projects. We capitalized interest costs on construction work in progress of $39 million, $89 million and $182 million for the years ended December 31, 2011, 2010 and 2009, 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 income (expense), net. We recognized net foreign currency exchange gain (losses) of $(99) million, $1 million and $(33) million for the years ended December 31, 2011, 2010 and 2009, respectively. See Note 13—Derivatives and Hedging.

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

We recognize deferred tax assets and liabilities for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of our assets and liabilities using the applicable jurisdictional tax rates in effect at year end. We record a valuation allowance for deferred tax assets when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We provide a valuation allowance to offset deferred tax assets for net operating losses ("NOL") 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 6—Income Taxes.

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

We maintain restricted cash investments that are pledged for debt service, as required under certain bank credit agreements. We classify such restricted cash investment balances in other current assets if the restriction is expected to expire within one year and in other assets if the restriction is expected to expire in greater than one year. At December 31, 2011, the aggregate carrying amount of our restricted cash investments was $928 million, of which $182 million and $746 million was classified in other current assets and other assets, respectively. At December 31, 2010, the aggregate carrying amount of our restricted cash investments was $47 million, classified in other assets. See Note 12—Debt.

Allowance for doubtful accounts—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 is unlikely to occur. 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. The allowance for doubtful accounts was $28 million and $38 million at December 31, 2011 and 2010, respectively.

Materials and supplies—Materials and supplies are carried at average cost less an allowance for obsolescence. The allowance for obsolescence was $73 million and $70 million at December 31, 2011 and 2010, 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. Assets held for sale were $26 million and less than $1 million at December 31, 2011 and 2010, respectively. See Note 7—Discontinued Operations.

Property and equipment—Property and equipment, consisting primarily of offshore drilling rigs and related equipment, represented approximately 64 percent of our total assets at December 31, 2011. The carrying amounts of these assets are based on 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. 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 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 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. During 2009, we adjusted the useful lives for 10 rigs, extending the estimated useful lives from between 30 and 35 years to between 33 and 50 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. For each of the years ended December 31, 2011, 2010 and 2009, the changes in estimated useful lives of these rigs resulted in a reduction in depreciation expense of $2 million ($0.01 per diluted share from continuing operations), $23 million ($0.07 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 and a drilling management services customer relationships intangible asset, 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, High-Specification Jackups, and Standard 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 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 fair value less cost to sell.

In the year ended December 31, 2011, we concluded that our assets held for sale were impaired, and we recognized a loss on impairment of $28 million. In the year ended December 31, 2010, we concluded that our Standard Jackup asset group was impaired, and we recognized a loss on impairment of $1.0 billion ($3.15 per diluted share from continuing operations), which had no tax effect. In the year ended December 31, 2009, we determined that our assets held for sale and our customer relationships intangible asset were impaired, and we recognized losses on the impairment of these assets in the amount of $279 million ($0.87 per diluted share from continuing operations), which had no tax effect, and $49 million ($0.15 per diluted share from continuing operations), which had no tax effect. See Note 5—Impairments and Note 11—Goodwill and Other Intangible Assets.

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. 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 testing on October 1, 2011, we concluded that our goodwill was impaired due to a decline in projected cash flows and market valuations for this reporting unit, and we recognized an estimated loss on impairment of goodwill in the amount of $5.2 billion ($16.15 per diluted share from continuing operations), which had no tax effect. As a result of our annual impairment testing in each of the years ended December 31, 2010 and 2009, we concluded that goodwill was not impaired. See Note 5—Impairments and Note 11—Goodwill and Other Intangible Assets.

For our trade name intangible asset, which we have identified as indefinite-lived, we estimate fair value using the relief from royalty method, which applies the income approach. As a result of our impairment testing in the years ended December 31, 2011 and 2010, we concluded that the trade name intangible asset for our drilling management services reporting unit was not impaired. As a result of impairment testing in the year ended December 31, 2009, we concluded that the trade name intangible asset for our drilling management services reporting unit was impaired, and we recognized a loss on impairment in the amount of $6 million ($0.02 per diluted share from continuing operations), which had no tax effect. See Note 5—Impairments and Note 11—Goodwill and Other Intangible Assets.

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

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

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

The obligations and related costs for our defined benefit pension and other postretirement benefit plans, retiree life insurance and medical benefits, are actuarially determined 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.

Pension and other postretirement benefit plan obligations represented an aggregate liability in the amount of their net underfunded status of $640 million and $469 million, at December 31, 2011 and 2010, respectively. Net periodic benefit costs were $88 million, $91 million and $87 million for the years ended December 31, 2011, 2010 and 2009, respectively. See Note 14—Postemployment Benefit Plans.

Contingent liabilities—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 that we expect 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 statement of financial position, results of operations and cash flows to present our oil and gas operating segment and our Caspian Sea operations as discontinued operations (see Note 7—Discontinued Operations). These reclassifications did not have a material effect on our consolidated statement of financial position, results of operations or cash flows.

Subsequent events—We evaluate subsequent events through the time of our filing on the date we issue our financial statements. See Note 28—Subsequent Events.

Note 3—New Accounting Pronouncements

Recently Issued Accounting Standards

Intangibles-goodwill and other—Effective January 1, 2012, we will adopt 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. We do not expect that our adoption will have a material effect on our consolidated financial statements.

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 the disclosures contained in our balance sheet or notes to consolidated financial statements.

Note 4—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. During 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 $756 million, and the assumption of current liabilities of $272 million and long-term debt of $1.6 billion. 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 $273 million, which was recorded as goodwill. Certain fair value measurements have not been completed, and the purchase price allocation remains preliminary due to the timing of the acquisition and due to the number of acquired assets and assumed liabilities. We continue to review the estimated fair values of property and equipment, intangible assets, and other assets and liabilities, and to evaluate the assumed tax positions and contingencies.

We have included approximately three months of operating results of Aker Drilling in our consolidated results of operations. Our operating revenues include approximately $100 million of contract drilling revenues associated with the operations of Aker Drilling for the year ended December 31, 2011.

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	Years ended December 31, 2010
Operating revenues	$ 9,454	$ 9,797
Operating income (loss)	(4,628)	1,975
Income (loss) from continuing operations	(5,806)	999
Per share earnings (loss) from continuing operations		
Basic	$ (18.33)	$ 3.02
Diluted	$ (18.33)	$ 3.02

The pro forma financial information includes various adjustments, primarily related to additional depreciation 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 dates or the results of operations for any future periods.

Note 5—Impairments

Assets held for sale—During the year ended December 31, 2011, we recognized an aggregate loss of $28 million ($0.09 per diluted share from continuing operations), which had a tax effect of less than $1 million, associated with the impairment of *GSF Britannia*, *George H. Galloway*, *GSF Labrador*, and *Searex IV*, which were each classified as an asset held for sale at the time of impairment. We measured the impairments as the amount by which the carrying amounts of these rigs and related assets exceeded the estimated fair values less costs to sell the rigs and related assets. We estimated the fair values of the rigs and related assets using significant observable inputs, including binding sale and purchase agreements for the assets.

During the year ended December 31, 2009, we determined that *GSF Arctic II* and *GSF Arctic IV*, both classified as assets held for sale, were impaired due to the global economic downturn and pressure on commodity prices, both of which had an adverse effect on our industry. We estimated the fair values of these rigs based on an 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 and considering our undertakings to the Office of Fair Trading in the U.K. (“OFT”) that required the sale of the rigs with certain limitations and in a limited amount of time. We based our estimates on significant unobservable inputs, including non-binding price quotes from unaffiliated parties, considering the then-current market conditions and restrictions imposed by the OFT. For the year ended December 31, 2009, as a result of our evaluation, we recognized a loss on impairment of $279 million ($0.87 per diluted share), which had no tax effect. In the year ended December 31, 2010, we completed the sale of these drilling units. See Note 10—Drilling Fleet.

Assets held and used—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. 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. Our valuation utilized the projection of the future performance of the asset group based on significant unobservable inputs, including assumptions regarding long-term projections for future revenues and costs, dayrates, rig utilization and idle time. As a result, we determined that the carrying amount of the Standard Jackup asset group exceeded its fair value, and we recognized a loss on impairment of long-lived assets in the amount of $1.0 billion ($3.15 per diluted share from continuing operations), which had no tax effect, during the year ended December 31, 2010. We did not have an impairment of our assets held and used in either of the years ended December 31, 2011 or 2009.

Goodwill and other indefinite-lived intangible assets—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, and we recognized our best estimate of the loss on impairment in the amount of $5.2 billion ($16.15 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 valuation required us to project the future performance of the contract drilling services reporting unit based on significant unobservable inputs, including assumptions for future commodity prices, projected demand for our services, rig availability and dayrates. We have not completed the measurement of our goodwill impairment due to the complexities involved in determining the implied fair value of goodwill. Our estimate is, therefore, subject to adjustment. We expect to complete the measurement of our goodwill impairment in the three months ending March 31, 2012. As a result of our annual impairment testing for our contract drilling services reporting unit in the year ended December 31, 2010 and 2009, we concluded that goodwill was not impaired.

During the year ended December 31, 2009, we determined that the trade name intangible asset associated with our drilling management services reporting unit was impaired due to market conditions resulting from the global economic downturn and continued pressure on commodity prices. 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. Our valuation required us to project the future performance of the drilling management services reporting unit based on significant unobservable inputs, including assumptions for future commodity prices, projected demand for our services, rig availability and dayrates. As a result of our valuations in the year ended December 31, 2009, we determined that the carrying amount of the trade name intangible asset exceeded its fair value, and we recognized a loss on impairment of $6 million ($0.02 per diluted share), which had no tax effect. In the years ended December 31, 2011 and 2010, we determined that we did not have an impairment of our trade name intangible asset.

Definite-lived intangible assets—During the year ended December 31, 2009, we determined that the customer relationships intangible asset associated with our drilling management services reporting unit was impaired due to market conditions resulting from the global economic downturn and continued pressure on commodity prices. 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. Our valuation required us to project the future performance of the drilling management services reporting unit based on significant unobservable inputs, including assumptions for future commodity prices, projected demand for our services, rig availability and dayrates. As a result of our valuation in the year ended December 31, 2009, we determined that the carrying amount of the customer relationships intangible asset exceeded its fair value, and we recognized a loss on impairment of $49 million ($0.15 per diluted share from continuing operations), which had no tax effect. We were not required to test our definite-lived intangible assets for impairment in either of the years ended December 31, 2011 or 2010.

Note 6—Income Taxes

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

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

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

	Years ended December 31,		
	2011	2010	2009
Current tax expense	$ 426	$ 450	$ 738
Deferred tax expense (benefit)	(31)	(114)	(15)
Income tax expense	$ 395	$ 336	$ 723

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,		
	2011	2010	2009
Income tax expense at the Swiss federal statutory rate	$ (425)	$ 101	$ 307
Taxes on earnings subject to rates greater than the Swiss federal statutory rate	285	107	288
Taxes on impairment loss subject to rates less than the Swiss federal statutory rate	409	79	—
Taxes on asset sales subject to rates less than the Swiss federal statutory rate	(16)	—	—
Taxes on litigation matters subject to rates less than the Swiss federal statutory rate	78	—	—
Changes in unrecognized tax benefits, net	62	71	135
Change in valuation allowance	19	4	49
Benefit from foreign tax credits	(28)	(23)	(49)
Taxes on asset acquisition costs at rates lower than the Swiss federal statutory rate	8	—	—
Other, net	3	(3)	(7)
Income tax expense	$ 395	$ 336	$ 723

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

	December 31, 2011	December 31, 2010
Deferred tax assets		
Drilling contract intangibles	$ 2	$ 6
Net operating loss carryforwards	341	184
Tax credit carryforwards	45	29
Accrued payroll expenses not currently deductible	77	72
Deferred income	67	84
Valuation allowance	(183)	(164)
Other	81	61
Total deferred tax assets	430	272
Deferred tax liabilities		
Depreciation and amortization	(749)	(680)
Drilling management services intangibles	(25)	(26)
Other	(37)	(26)
Total deferred tax liabilities	(811)	(732)
Net deferred tax liabilities	$ (381)	$ (460)

Our deferred tax assets include U.S. foreign tax credit carryforwards of $45 million, which will expire between 2015 and 2021. Deferred tax assets related to our NOLs were generated in various worldwide tax jurisdictions. The tax effect of our Brazilian NOLs, which do not expire, was $57 million and $62 million at December 31, 2011 and 2010, respectively. In connection with our acquisition of Aker Drilling, we acquired $141 million of Norwegian NOLs, which do not expire.

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

	December 31, 2011	December 31, 2010
Valuation allowance for non-current deferred tax assets	$ 183	$ 164

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, 2011, the amount of indefinitely reinvested earnings was approximately $2.2 billion. If all of these indefinitely reinvested earnings were distributed, we would be subject to estimated taxes of $150 million to $200 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, 2011	2010	2009
Balance, beginning of period	$ 485	$ 460	$ 372
Additions for current year tax positions	45	46	64
Additions for prior year tax positions	23	9	62
Reductions for prior year tax positions	—	(11)	(22)
Settlements	(42)	(17)	(3)
Reductions related to statute of limitation expirations	(2)	(2)	(13)
Balance, end of period	$ 509	$ 485	$ 460

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, 2011	December 31, 2010
Unrecognized tax benefits, excluding interest and penalties	$ 509	$ 485
Interest and penalties	272	235
Unrecognized tax benefits, including interest and penalties	$ 781	$ 720

For the years ended December 31, 2011, 2010 and 2009, we recognized interest and penalties related to our unrecognized tax benefits, recorded as a component of income tax expense, in the amount of $37 million, $35 million and $51 million, respectively. If recognized, $781 million of our unrecognized tax benefits, including interest and penalties, as of December 31, 2011, 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, 2012 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 2003. For the years ended December 31, 2011, 2010 and 2009, the amount of current tax benefit recognized from the settlement of disputes with tax authorities and from the expiration of statutes of limitations was insignificant.

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 17 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. Accordingly, the trial previously scheduled to be heard in U.S. Tax Court in February 2012 has been cancelled. 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, except a claim regarding transfer pricing for certain charters of drilling rigs between our subsidiaries, resulting in a total proposed adjustment of approximately $50 million, excluding interest. We believe an unfavorable outcome on this assessment with respect to 2005 activities would not result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Although we believe the transfer pricing for these charters is materially correct, we have been unable to reach a resolution with the tax authorities.

In May 2010, we received an assessment from the U.S. tax authorities related to our 2006 and 2007 U.S. federal income tax returns. In July 2010, we filed a protest letter with the U.S. tax authorities responding to this assessment. 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. These two items would result in net adjustments of approximately $278 million of additional taxes, excluding interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We believe our returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims.

In addition, the May 2010 assessment included adjustments related to a series of restructuring transactions that occurred between 2001 and 2004. These restructuring transactions impacted our basis in our former subsidiary, TODCO, which we disposed of in 2004 and 2005. The authorities are disputing the amount of capital losses that resulted from the disposition of TODCO. We utilized a portion of the capital losses to offset capital gains on our U.S federal income tax returns for 2006 through 2009. The majority of the capital losses were unutilized and expired on December 31, 2009. The adjustments would also impact the amount of certain net operating losses and other carryovers in 2006 and later years. The authorities are also contesting the characterization of certain amounts of income received in 2006 and 2007 as capital gain and thus the availability of the capital gain for offset by the capital loss. These claims with respect to our U.S. federal income tax returns for 2006 through 2009 could result in net tax adjustments of approximately $295 million. An unfavorable outcome on these potential adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We believe that our U.S federal income tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

The May 2010 assessment also included certain claims with respect to withholding taxes and certain other items resulting in net tax adjustments of approximately $160 million, excluding interest. In addition, the tax authorities assessed penalties associated with the various tax adjustments for the 2006 and 2007 audits in the aggregate amount of approximately $88 million, excluding interest. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against potential claims.

See Note 28—Subsequent Events.

Norway tax investigations—Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 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 (a) approximately $262 million plus interest, related to certain restructuring transactions, (b) approximately $115 million plus interest, related to the migration of a subsidiary that was previously subject to tax in Norway, (c) approximately $69 million plus interest, related to a 2001 dividend payment and (d) approximately $7 million plus interest, related to certain foreign exchange deductions and dividend withholding tax. We have filed or expect to file appeals to these tax assessments. With respect to the tax assessment related to the migration of a subsidiary, we provided a guarantee in the amount of approximately $120 million, plus interest, while this dispute is addressed by the Norwegian courts. Furthermore, we may be required to provide some form of additional financial security, in an amount up to $776 million, including interest and penalties, for these other assessed amounts while these disputes are appealed and addressed by the Norwegian courts. The authorities have indicated that they plan to seek penalties of 60 percent on most but not all matters. For these matters, we believe our returns are materially correct as filed, and we have and will continue to respond to all information requests from the Norwegian authorities. 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 2001, as well as inaccuracies in Norwegian statutory financial statements for the years ended December 31, 1996 through 2001. The criminal trial has been scheduled for December 2012. Two employees of our former external tax advisors were also issued indictments with respect to the disclosures in our tax returns. We believe these charges are without merit and plan to vigorously defend our subsidiaries to the fullest extent. We intend to vigorously contest any assertions by the Norwegian civil and criminal authorities in connection with the various transactions being investigated. In October 2011, the Norwegian authorities issued criminal indictments against a Norwegian tax attorney related to certain of our restructuring transactions and to a 2001 dividend payment. An unfavorable outcome on these Norwegian civil and criminal tax matters could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. However, while we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate resolution of these matters 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 Note 28—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 $109 million, plus a 75 percent penalty in the amount of $82 million and interest through December 31, 2011 in the amount of $150 million. 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. 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.

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 assessments to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Note 7—Discontinued Operations

Oil and gas properties—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, a component of our other operations segment, which comprises the exploration, development and production activities performed by Challenger Minerals Inc. and Challenger Minerals (North Sea) Limited, our wholly owned oil and gas subsidiaries. In October 2011, we completed the sale of Challenger Minerals (North Sea) Limited for aggregate net cash proceeds of $24 million and we recognized a gain on the disposal of the discontinued operations of $12 million. See Note 28—Subsequent Events.

Caspian Sea operations—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 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 ($0.52 per diluted share from discontinued operations), which had no tax effect. 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.

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, 2011	2010	2009
Operating revenues	$ 62	$ 110	$ 115
Costs and expenses	(55)	(99)	(110)
Loss on impairment (a)	(10)	(2)	—
Gain on disposal of discontinued operations, net	181	—	—
Income from discontinued operations before income tax expense	178	9	5
Income tax benefit (expense)	19	25	(31)
Income (loss) from discontinued operations, net of tax	$ 197	$ 34	$ (26)

(a) During the year ended December 31, 2011, we recognized a loss on impairment of our oil and gas properties, which were classified as assets held for sale, in the amount of $10 million ($0.03 per diluted share from discontinued operations) 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 unobservable inputs, including non-binding price quotes from unaffiliated parties. During the year ended December 31, 2010, we determined that the goodwill associated with our former oil and gas properties reporting unit was impaired, and we recognized a loss on impairment of the full carrying amount of the goodwill associated with the reporting unit in the amount of $2 million ($0.01 per diluted share from discontinued operations), which had no tax effect.

Assets and liabilities of discontinued operations—As a result of our decision to discontinue the operations of our oil and gas properties reporting unit and the operations of our Caspian Sea subsidiary, we also reclassified the related assets and liabilities of these components of our business to other current assets, other assets, other current liabilities and other long-term liabilities as of December 31, 2010. The carrying amounts of the major classes of assets and liabilities associated with these operations were classified as follows (in millions):

	December 31, 2011	2010
Assets		
Oil and gas properties, net	$ 24	$ —
Other related assets	2	—
Assets held for sale	$ 26	$ —
Accounts receivable	$ 6	$ 22
Other assets	25	17
Other current assets	$ 31	$ 39
Rig and related equipment, net	$ —	$ 86
Oil and gas properties, net	—	53
Other assets	$ —	$ 139
Liabilities		
Accounts payable	$ 3	$ 15
Other liabilities	14	13
Other current liabilities	$ 17	$ 28
Asset retirement obligation	$ —	$ 9
Deferred taxes	—	19
Other long-term liabilities	$ —	$ 28

Note 8—Earnings (Loss) Per Share

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

	Years ended December 31,					
	2011		2010		2009	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
Numerator for earnings per share						
Income (loss) from continuing operations attributable to controlling interest	$ (5,922)	$ (5,922)	$ 927	$ 927	$ 3,207	$ 3,207
Undistributed earnings allocable to participating securities	—	—	(5)	(5)	(18)	(18)
Income (loss) from continuing operations available to shareholders	$ (5,922)	$ (5,922)	$ 922	$ 922	$ 3,189	$ 3,189
Denominator for earnings per share						
Weighted-average shares outstanding	322	322	320	320	320	320
Effect of stock options and other share-based awards	—	—	—	—	—	1
Weighted-average shares for per share calculation	322	322	320	320	320	321
Per share earnings (loss) from continuing operations	$ (18.40)	$ (18.40)	$ 2.88	$ 2.88	$ 9.95	$ 9.92

For the years ended December 31, 2011, 2010 and 2009, respectively, we have excluded 2.4 million, 2.2 million and 1.7 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 12—Debt.

Note 9—Other Comprehensive Income

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

	Years ended December 31, 2011			2010			2009		
	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	Total	Controlling interest	Non-controlling interest (a)	Total
Unrecognized components of net periodic benefit costs	$ (204)	$ —	$ (204)	$ (8)	$ —	$ (8)	$ 37	$ —	$ 37
Unrecognized gain (loss) on derivative instruments	3	(16)	(13)	(10)	(19)	(29)	(4)	2	(2)
Unrecognized loss on marketable securities	(13)	—	(13)	—	—	—	—	—	—
Recognized components of net periodic benefit costs	25	—	25	16	—	16	24	—	24
Recognized (gain) loss on derivative instruments	(1)	12	11	14	(2)	12	3	3	6
Recognized loss on marketable securities	13	—	13	—	—	—	1	—	1
Other comprehensive income (loss) before income taxes	(177)	(4)	(181)	12	(21)	(9)	61	5	66
Income taxes related to other comprehensive income	13	—	13	(9)	—	(9)	24	—	24
Other comprehensive income (loss), net of tax	$ (164)	$ (4)	$ (168)	$ 3	$ (21)	$ (18)	$ 85	$ 5	$ 90

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

The components of accumulated other comprehensive income (loss), net of tax, were as follows (in millions):

	December 31, 2011			December 31, 2010		
	Controlling interest	Non-controlling interest	Redeemable non-controlling interest	Controlling interest	Non-controlling interest	Redeemable non-controlling interest
Unrecognized components of net periodic benefit costs (a)	$ (501)	$ —	$ —	$ (335)	$ —	$ —
Unrecognized gain (loss) on derivative instruments	7	(3)	(17)	5	(3)	(13)
Unrecognized loss on marketable securities	(2)	—	—	(2)	—	—
Accumulated other comprehensive income (loss)	$ (496)	$ (3)	$ (17)	$ (332)	$ (3)	$ (13)

(a) Amounts are net of income tax effect of $49 million and $36 million for December 31, 2011 and 2010, respectively.

Note 10—Drilling Fleet

Expansion—Construction work in progress, recorded in property and equipment, was $1.4 billion and $1.5 billion at December 31, 2011 and 2010, respectively. Capital expenditures and other capital additions, including capitalized interest, for our major construction projects for the six years ended December 31, 2011 were as follows (in millions):

	Years ended December 31,				
	2011	2010	2009	2008 - 2006	Total
Ultra-Deepwater Floater TBN1 (a)	$ 138	$ —	$ —	$ —	$ 138
Ultra-Deepwater Floater TBN2 (a)	137	—	—	—	137
Transocean Honor (b)	119	97	—	—	216
Transocean Siam Driller (c)	110	9	—	—	119
Transocean Andaman (c)	110	9	—	—	119
Transocean Ao Thai (d)	79	—	—	—	79
Deepwater Champion (e) (f)	43	206	263	264	776
Discoverer Luanda (f) (g)	12	174	220	315	721
Discoverer India (f)	6	203	291	250	750
Dhirubhai Deepwater KG2 (f) (h)	—	36	371	270	677
Development Driller III (e) (f)	—	24	117	483	624
Discoverer Inspiration (f)	—	12	224	443	679
Discoverer Americas (f)	—	6	148	478	632
Discoverer Clear Leader (f)	—	6	115	516	637
Petrobras 10000 (f) (i)	—	6	735	—	741
Dhirubhai Deepwater KG1 (f) (h)	—	—	295	384	679
Sedco 700-series upgrades (f)	—	—	71	520	591
Capitalized interest	39	89	182	240	550
Mobilization costs	20	89	155	—	264
Total	$ 813	$ 966	$ 3,187	$ 4,163	$ 9,129

(a) The costs for Ultra-Deepwater Floater TBN1 and Ultra-Deepwater Floater TBN2 include our initial investments of $136 million and $136 million, respectively, representing the estimated fair values of the rigs at the time of our acquisition of Aker Drilling in October 2011. The fair values of our initial investments are preliminary and subject to change. See Note 4—Business Combination.

(b) In November 2010, we purchased *Transocean Honor,* a PPL Pacific Class 400 design jackup, which is under construction at PPL Shipyard Pte Ltd. in Singapore and is expected for delivery in the first quarter of 2012.

(c) In December 2010, we purchased *Transocean Siam Driller* and *Transocean Andaman*, two Keppel FELS Super B class design jackups, which are under construction at Keppel FELS' yard in Singapore and are expected for delivery in the first quarter of 2013.

(d) In June 2011, we purchased *Transocean Ao Thai*, a Keppel FELS Super B class design jackup, which is under construction at Keppel FELS' yard in Singapore and is expected for delivery in the third quarter of 2013.

(e) The costs for *Deepwater Champion* and *Development Driller III* include our initial investments of $109 million and $350 million, respectively, representing the estimated fair values of the rigs at the time of our merger with GlobalSantaFe Corporation ("GlobalSantaFe") in November 2007.

(f) The accumulated construction costs of these rigs are no longer included in construction work in progress, as their construction projects had been completed as of December 31, 2011.

(g) The costs for *Discoverer Luanda* represent 100 percent of expenditures incurred since inception. ADDCL is responsible for all of these costs. We hold a 65 percent interest in the ADDCL joint venture, and Angco Cayman Limited, a Cayman Islands company ("Angco Cayman"), holds the remaining 35 percent interest.

(h) The costs for *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2* represent 100 percent of TPDI's expenditures, including those incurred prior to our investment in the joint venture. TPDI is responsible for all of these costs. We hold a 50 percent interest in the TPDI joint venture, and Quantum Pacific Management Limited, a Cypriot company and successor in interest to Pacific Drilling Limited ("Quantum"), holds the remaining 50 percent interest.

(i) In June 2008, we reached an agreement with a joint venture formed by subsidiaries of Petrobras and Mitsui to acquire *Petrobras 10000* under a capital lease contract. In connection with the agreement, we agreed to provide assistance and advisory services for the construction of the rig and operating management services once the rig commenced operations. On August 4, 2009, we accepted delivery of *Petrobras 10000* and recorded non-cash additions of $716 million to property and equipment, net, along with a corresponding increase to long-term debt. Total capital additions include $716 million in capital costs incurred by Petrobras and Mitsui for the construction of the drillship and $19 million of other capital expenditures. The capital lease agreement has a 20-year term, after which we will have the right and obligation to acquire the drillship for one dollar. See Note 12—Debt and Note 15—Commitments and Contingencies.

During the year ended December 31, 2011, in connection with our acquisition of Aker Drilling, we acquired two Harsh Environment, Ultra-Deepwater semisubmersibles, *Transocean Spitsbergen* and *Transocean Barents*, which are currently operating on long-term contracts in Norway. See Note 4—Business Combination.

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 12—Debt.

Dispositions—During the year ended December 31, 2011, in connection with our efforts to dispose of non-strategic assets, we sold the Standard Jackups, *Transocean Mercury*, *GSF Britannia*, *George H. Galloway, GSF Labrador*, and *GSF Adriatic XI, and* the swamp barge *Searex IV*, along with related equipment, and we received net aggregate proceeds of $163 million and recognized a net gain on the disposals of these assets of $19 million ($0.06 per diluted share from continuing operations), which had no tax effect. For the year ended December 31, 2011, we recognized a net loss on disposal of other unrelated assets of $15 million.

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 21—Fair Value of Financial Instruments). 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 ($0.04 per diluted share from continuing operations), which had no tax effect for the year ended December 31, 2010. For the year ended December 31, 2010, we recognized a net gain on disposal of other unrelated assets of $5 million.

During the year ended December 31, 2009, in connection with our sale of *Sedco 135-D* and disposals of unrelated property and equipment, we received aggregate net proceeds of $18 million, and we recognized a loss on disposal of assets of $9 million ($0.03 per diluted share from continuing operations), which had no tax effect.

Unconsolidated affiliates—During the year ended December 31, 2011, we completed the sale of our 50 percent ownership interest in Overseas Drilling Limited, a Cayman Islands company, which owns the drillship *Joides Resolution*, which was adapted for scientific research. In connection with the sale, we received net proceeds of $22 million and recognized a net gain of $13 million ($0.04 per diluted share from continuing operations), recorded in other, net, which had no tax effect.

During the year ended December 31, 2009, we received net proceeds of $4 million in exchange for our 45 percent ownership interest in Caspian Drilling Company Limited, which operates *Dada Gorgud* and *Istigal* under long-term bareboat charters with the owner of the rigs and $38 million in exchange for our 40 percent ownership interest in Arab Drilling & Workover Company. In connection with the sales of our ownership interests, we recognized an aggregate net gain of $30 million ($0.09 per diluted share from continuing operations), recorded in other, net on our consolidated statement of operations.

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. During 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, for the year ended December 31, 2010, 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 15—Commitments and Contingencies.

Note 11—Goodwill and Other Intangible Assets

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

	Year ended December 31, 2011			Year ended December 31, 2010		
	Gross carrying amount	Accumulated impairment	Net carrying amount	Gross carrying amount	Accumulated impairment	Net carrying amount
Contract drilling services						
Balance, beginning of period	$ 10,626	$ (2,494)	$ 8,132	$ 10,626	$ (2,494)	$ 8,132
Impairment	—	(5,200)	(5,200)	—	—	—
Business combination	273	—	273	—	—	—
Balance, end of period	10,899	(7,694)	3,205	10,626	(2,494)	8,132
Drilling management services						
Balance, beginning of period	176	(176)	—	176	(176)	—
Balance, end of period	176	(176)	—	176	(176)	—
Total goodwill						
Balance, beginning of period	10,802	(2,670)	8,132	10,802	(2,670)	8,132
Impairment	—	(5,200)	(5,200)	—	—	—
Business combination	273	—	273	—	—	—
Balance, end of period	$ 11,075	$ (7,870)	$ 3,205	$ 10,802	$ (2,670)	$ 8,132

The gross carrying amounts of the ADTI trade name, which we consider to be an indefinite-lived intangible asset, and accumulated impairment were as follows (in millions):

	Year ended December 31, 2011			Year ended December 31, 2010		
	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
Balance, end of period	$ 76	$ (37)	$ 39	$ 76	$ (37)	$ 39

Definite-lived intangible assets—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, 2011			Year ended December 31, 2010		
	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	$ (185)	$ 6	$ 191	$ (167)	$ 24
Amortization	—	(6)	(6)	—	(18)	(18)
Balance, end of period	191	(191)	—	191	(185)	6
Customer relationships						
Balance, beginning of period	148	(89)	59	148	(84)	64
Amortization	—	(5)	(5)	—	(5)	(5)
Balance, end of period	148	(94)	54	148	(89)	59
Total definite-lived intangible assets						
Balance, beginning of period	339	(274)	65	339	(251)	88
Amortization	—	(11)	(11)	—	(23)	(23)
Balance, end of period	$ 339	$ (285)	$ 54	$ 339	$ (274)	$ 65
Drilling contract intangible liabilities						
Balance, beginning of period	$ 1,494	$ (1,342)	$ 152	$ 1,494	$ (1,226)	$ 268
Amortization	—	(51)	(51)	—	(116)	(116)
Balance, end of period	$ 1,494	$ (1,393)	$ 101	$ 1,494	$ (1,342)	$ 152

We amortize the drilling contract intangibles over the term of the respective drilling contracts using the straight-line method of amortization, recognized in contract intangible revenues on our consolidated statements of operations. We amortize the customer relationships intangible asset over its 15-year life using the straight-line method of amortization, recognized in operating and maintenance expense on our consolidated statements of operations. The estimated net future amortization related to intangible assets and liabilities as of December 31, 2011, was as follows (in millions):

	Drilling contract intangibles	Customer relationships
Years ending December 31,		
2012	$ (41)	$ 5
2013	(25)	5
2014	(15)	5
2015	(14)	5
2016	(6)	5
Thereafter	—	29
Total intangible assets (liabilities), net	$ (101)	$ 54

Note 12—Debt

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

	December 31, 2011			December 31, 2010		
	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
ODL Loan Facility	$ —	$ —	$ —	$ 10	$ —	$ 10
Commercial paper program (a)	—	—	—	88	—	88
6.625% Notes due April 2011 (a)	—	—	—	167	—	167
5% Notes due February 2013	253	—	253	255	—	255
5.25% Senior Notes due March 2013 (a)	507	—	507	511	—	511
TPDI Credit Facilities due March 2015	—	473	473	—	560	560
4.95% Senior Notes due November 2015 (a)	1,120	—	1,120	1,099	—	1,099
Aker Revolving Credit and Term Loan Facility due December 2015	594	—	594	—	—	—
5.05% Senior Notes due December 2016 (a)	999	—	999	—	—	—
Callable Bonds due February 2016	267	—	267	—	—	—
ADDCL Credit Facilities due December 2017	—	217	217	—	242	242
Eksportfinans Loans due January 2018	884	—	884	—	—	—
6.00% Senior Notes due March 2018 (a)	998	—	998	997	—	997
7.375% Senior Notes due April 2018 (a)	247	—	247	247	—	247
TPDI Notes due October 2019	—	148	148	—	148	148
6.50% Senior Notes due November 2020 (a)	899	—	899	899	—	899
6.375% Senior Notes due December 2021 (a)	1,199	—	1,199	—	—	—
7.45% Notes due April 2027 (a)	97	—	97	96	—	96
8% Debentures due April 2027 (a)	57	—	57	57	—	57
7% Notes due June 2028	311	—	311	313	—	313
Capital lease contract due August 2029	676	—	676	694	—	694
7.5% Notes due April 2031 (a)	598	—	598	598	—	598
1.625% Series A Convertible Senior Notes due December 2037 (a)	—	—	—	11	—	11
1.50% Series B Convertible Senior Notes due December 2037 (a)	30	—	30	1,625	—	1,625
1.50% Series C Convertible Senior Notes due December 2037 (a)	1,663	—	1,663	1,605	—	1,605
6.80% Senior Notes due March 2038 (a)	999	—	999	999	—	999
7.35% Senior Notes due December 2041 (a)	300	—	300	—	—	—
Total debt	12,698	838	13,536	10,271	950	11,221
Less debt due within one year						
ODL Loan Facility	—	—	—	10	—	10
Commercial paper program (a)	—	—	—	88	—	88
6.625% Notes due April 2011 (a)	—	—	—	167	—	167
TPDI Credit Facilities due March 2015	—	70	70	—	70	70
Aker Revolving Credit and Term Loan Facility due December 2015	90	—	90	—	—	—
ADDCL Credit Facilities due November 2017	—	27	27	—	25	25
Eksportfinans Loans due January 2018	142	—	142	—	—	—
Capital lease contract due August 2029	17	—	17	16	—	16
1.625% Series A Convertible Senior Notes due December 2037 (a)	—	—	—	11	—	11
1.50% Series B Convertible Senior Notes due December 2037 (a)	30	—	30	1,625	—	1,625
1.50% Series C Convertible Senior Notes due December 2037 (a)	1,663	—	1,663	—	—	—
Total debt due within one year	1,942	97	2,039	1,917	95	2,012
Total long-term debt	$ 10,756	$ 741	$ 11,497	$ 8,354	$ 855	$ 9,209

(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 commercial paper program and the Five-Year Revolving Credit Facility. Transocean Ltd. and Transocean Inc. are not subject to any significant restrictions on their ability to obtain funds from their consolidated subsidiaries by dividends, loans or return of capital distributions. See Note 26—Condensed Consolidating Financial Statements.

Scheduled maturities—In preparing the scheduled maturities of our debt, we assume the noteholders will exercise their options to require us to repurchase the 1.50% Series C Convertible Senior Notes in December 2012. At December 31, 2011, the scheduled maturities of our debt were as follows (in millions):

Years ending December 31,	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
2012	$ 2,001	$ 97	$ 2,098
2013	1,002	98	1,100
2014	235	99	334
2015	1,331	322	1,653
2016	1,696	34	1,730
Thereafter	6,450	188	6,638
Total debt, excluding unamortized discounts, premiums and fair value adjustments	12,715	838	13,553
Total unamortized discounts, premiums and fair value adjustments	(17)	—	(17)
Total debt	$ 12,698	$ 838	$ 13,536

Commercial paper program—We maintain a commercial paper program (the "Program"), which is supported by the Five-Year Revolving Credit Facility, under which we may issue privately placed, unsecured commercial paper notes for general corporate purposes up to a maximum aggregate outstanding amount of $1.5 billion. Proceeds from commercial paper issuance under the Program may be used for general corporate purposes. At December 31, 2011, we had no commercial paper outstanding.

Five-Year Revolving Credit Facility—We have a $2.0 billion revolving credit facility under the Five-Year Revolving Credit Facility Agreement dated November 1, 2011 (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 our Debt Rating (based on our current Debt Rating, a margin of 1.625 percent) or (2) the Base Rate plus the Five-Year Revolving Credit Facility Margin, less one percent per annum. Throughout the term of the Five-Year Revolving Credit Facility, we pay a facility fee on the daily amount of the underlying commitment, whether used or unused, which ranges from 0.13 percent to 0.33 percent, based on our Debt Rating, and was 0.275 percent at December 31, 2011. The Five-Year Revolving Credit Facility expires on November 1, 2016, and borrowings may be prepaid in whole or in part without premium or penalty. 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. At December 31, 2011, we had $24 million in letters of credit issued and outstanding, we had no borrowings outstanding, and we had $2.0 billion available borrowing capacity under the Five-Year Revolving Credit Facility.

6.625% Notes—In April 2001, we issued $700 million aggregate principal amount of 6.625% Notes due April 2011. On April 15, 2011, we repaid the 6.625% Notes at maturity.

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 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. The indentures related to the 5% Notes and the 7% Notes contain limitations on creating liens and sale/leaseback transactions. At December 31, 2011, $250 million and $300 million aggregate principal amount of the 5% Notes and the 7% Notes, respectively, remained outstanding. See Note 13—Derivatives and Hedging.

5.25%, 6.00% and 6.80% Senior Notes—In December 2007, Transocean Inc. 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"). Transocean Inc. 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. 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, 2011, $500 million, $1.0 billion and $1.0 billion principal amount of the 5.25% Senior Notes, the 6.00% Senior Notes and the 6.80% Senior Notes, respectively, were outstanding. See Note 13—Derivatives and Hedging.

TPDI Credit Facilities—TPDI has a bank credit agreement for a $1.265 billion secured credit facility (the "TPDI Credit Facilities"), comprised of a $1.0 billion senior term loan, a $190 million junior term loan and a $75 million revolving credit facility, which was established to finance the construction of and is secured by *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. 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 may be prepaid in whole or in part without premium or penalty. 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. At December 31, 2011, $945 million was outstanding under the TPDI Credit Facilities, of which $472 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on December 31, 2011 was 2.2 percent. See Note 13—Derivatives and Hedging.

In April 2010, TPDI obtained a letter of credit in the amount of $60 million to satisfy its liquidity requirements under the TPDI Credit Facilities. The letter of credit was issued under an uncommitted credit facility that has been established by one of our subsidiaries. Additionally, TPDI is required to maintain certain cash balances in restricted accounts for the payment of the scheduled installments on the TPDI Credit Facilities. TPDI had restricted cash investments of $23 million at December 31, 2011 and 2010.

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, 2011, $1.1 billion and $900 million aggregate principal amount of the 4.95% Senior Notes and the 6.50% Senior Notes, respectively, were outstanding. See Note 13—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 the credit rating for the notes assigned by Moody's Investors Service or Standard & Poor's Ratings Services. We are required to pay interest on the 2011 Senior Notes on June 15 and December 15 of each year, beginning June 15, 2012. 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. 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. At December 31, 2011, $1.0 billion, $1.2 billion and $300 million aggregate principal amount of the 5.05% Senior Notes, the 6.375% Senior Notes and the 7.35% Senior Notes, respectively, were outstanding.

Aker Revolving Credit and Term Loan Facility—In connection with our acquisition of Aker Drilling, we assumed the outstanding borrowings under a credit facility established by the Revolving Credit and Term Loan Facility Agreement dated February 21, 2011 (the "Aker Revolving Credit and Term Loan Facility"), comprised of a $500 million revolving credit facility and a $400 million term loan, which is secured by *Transocean Spitsbergen* and *Transocean Barents*. The Aker Revolving Credit and Term Loan Facility bears interest at LIBOR plus a margin of 2.50 percent and mandatory costs, and requires scheduled quarterly installments on the term loan. The Aker Revolving Credit and Term Loan Facility expires in December 2015 and may be prepaid in whole or in part without premium or penalty. The Aker Revolving Credit and Term Loan Facility includes covenants requiring minimum liquidity, a maximum leverage ratio, a minimum interest coverage ratio, a minimum current ratio, and a minimum equity ratio, as defined. At December 31, 2011, $594 million was outstanding under the Aker Revolving Credit and Term Loan Facility at a weighted-average interest rate of 3.0 percent.

Callable Bonds—In connection with our acquisition of Aker Drilling, we assumed the obligations associated with 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"), 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. At December 31, 2011, 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 $158 million and $94 million, respectively, using an exchange rate of NOK 5.9631 to US $1.00. See Note 13—Derivatives and Hedging.

ADDCL Credit Facilities—ADDCL has a senior secured bank credit agreement for a credit facility (the "ADDCL Primary Loan Facility") comprised of Tranche A and Tranche C for $215 million and $399 million, respectively, which was established to finance the construction of and is secured by *Discoverer Luanda.* 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 payments and matures in December 2017. 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, 2011, $190 million was outstanding under Tranche A at a weighted-average interest rate of 1.5 percent. At December 31, 2011, $399 million was outstanding under Tranche C, which was eliminated in consolidation.

Additionally, ADDCL has a secondary bank credit agreement for a $90 million credit facility (the "ADDCL Secondary Loan Facility" and together with the ADDCL Primary Loan Facility, the "ADDCL Credit Facilities"), for which one of our subsidiaries provides 65 percent of the total commitment. The facility bears interest at LIBOR plus the applicable margin, ranging from 3.125 percent to 5.125 percent, depending on certain milestones. 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. 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 the occurrence of a credit rating assignment of less than Baa3 or BBB- by Moody's Investors Service or Standard & Poor's Ratings Services, respectively, for Transocean Inc.'s long-term, unsecured, unguaranteed and unsubordinated indebtedness. At December 31, 2011, $78 million was outstanding under the ADDCL Secondary Loan Facility, of which $51 million was provided by one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on December 31, 2011 was 3.7 percent.

ADDCL is required to maintain certain cash balances in restricted accounts for the payment of the scheduled installments on the ADDCL Credit Facilities. ADDCL had restricted cash investments of $16 million at December 31, 2011 and 2010.

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"), which were established to finance the construction and delivery of *Transocean Spitsbergen* and *Transocean Barents*. 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, 2011, $427 million and $462 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, 2011, the aggregate principal amount of the Aker Restricted Cash Investments was $889 million.

7.375% Senior Notes—In March 2002, we issued $247 million principal amount of our 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, 2011, $246 million principal amount of the 7.375% Senior Notes was outstanding.

TPDI Notes—TPDI has issued promissory notes (the "TPDI Notes") payable to its two shareholders, Quantum and one of our subsidiaries, which have maturities through October 2019. At December 31, 2011, the aggregate outstanding principal amount was $296 million, of which $148 million was due to one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on December 31, 2011 was 2.5 percent.

7.5% Notes—In April 2001, Transocean Inc. issued $600 million aggregate principal amount of 7.5% Notes due April 2031. 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, 2011, $600 million principal amount of 7.5% Notes was outstanding.

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 7.45% Notes and the 8% Debentures are redeemable at any time at Transocean Inc.'s option subject to a make-whole premium. 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. At December 31, 2011, $100 million and $57 million principal amount of the 7.45% Notes and the 8% Debentures, respectively, were outstanding.

Capital lease contract—In August 2009, we accepted delivery of *Petrobras 10000*, an asset held under capital lease, and we recorded non-cash capital additions of $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 10—Drilling Fleet and Note 15—Commitments and Contingencies.

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, 2011, the Convertible Senior Notes could be converted under the circumstances specified below at a rate of 6.1902 shares per $1,000 note, equivalent to a conversion price of $161.55 per share, subject to adjustments upon the occurrence of certain events. In the event of certain fundamental changes that occur on or before December 20, 2012 with respect to Series C Convertible Senior Notes, we will, in some cases, increase the conversion rate for a holder electing to convert notes in connection with such fundamental change. Upon conversion, we will 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 may 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, 2011, 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 may 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 have the right to require us to repurchase their notes on December 14, 2012, 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 Convertible Senior Notes were as follows (in millions):

	December 31, 2011			December 31, 2010		
	Principal amount	Unamortized discount	Carrying amount	Principal amount	Unamortized discount	Carrying amount
Carrying amount of liability component						
Series A Convertible Senior Notes due 2037	$ —	$ —	$ —	$ 11	$ —	$ 11
Series B Convertible Senior Notes due 2037	30	—	30	1,680	(55)	1,625
Series C Convertible Senior Notes due 2037	1,722	(59)	1,663	1,722	(117)	1,605

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

	December 31,	
	2011	2010
Carrying amount of equity component		
Series A Convertible Senior Notes due 2037	$ —	$ 1
Series B Convertible Senior Notes due 2037	4	210
Series C Convertible Senior Notes due 2037	276	276

Including the amortization of the unamortized discount, the effective interest rates for the Series C Convertible Senior Notes was 5.28 percent. At December 31, 2011, 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,		
	2011	2010	2009
Interest expense			
Series A Convertible Senior Notes due 2037	$ —	$ 58	$ 85
Series B Convertible Senior Notes due 2037	78	98	100
Series C Convertible Senior Notes due 2037	84	98	100

Holders of the Series B Convertible Senior Notes had the option to require us to repurchase all or any part of such holders' notes on December 15, 2011. As a result, we were required to repurchase an aggregate principal amount of $1.7 billion of our Series B Convertible Senior Notes for an aggregate cash payment of $1.7 billion. See Note 28—Subsequent Events.

Holders of the Series A Convertible Senior Notes had the option to require us to repurchase all or any part of such holders' notes on December 15, 2010. As a result, we were required to repurchase an aggregate principal amount of $1,288 million of our Series A Convertible Senior Notes for an aggregate cash payment of $1,288 million. In January 2011, we redeemed the remaining $11 million aggregate principal amount of the Series A Convertible Senior Notes.

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.

During the year ended December 31, 2009, we repurchased an aggregate principal amount of $901 million of the Series A Convertible Senior Notes for an aggregate cash payment of $865 million. We recognized a loss of $28 million associated with the debt component of the instrument and recorded additional paid-in capital of $22 million associated with the equity component.

Note 13—Derivatives and Hedging

Derivatives designated as hedging instruments—Two of our wholly owned subsidiaries have entered into 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 4.95% Senior Notes, 5.25% Senior Notes and the 5% Notes. 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 perfectly offset changes in the fair value of the hedged fixed-rate notes. Through the stated maturities of the interest rate swaps, 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 London Interbank Offered Rate plus a margin.

Additionally, TPDI has entered into interest rate swaps, which have been designated and have qualified as a cash flow hedge, to reduce the variability of cash interest payments associated with the variable rate borrowings under the TPDI Credit Facilities. The aggregate notional amount corresponds with the aggregate outstanding amount of the borrowings under the TPDI Credit Facilities.

Aker Drilling entered into cross-currency interest rate swaps, which we have designated and which qualify as a cash flow hedge, to reduce the variability of cash interest payments associated with the changes in the U.S. dollar to Norwegian kroner exchange rate. The aggregate notional amount corresponds with the aggregate outstanding amount of the Callable Bonds.

At December 31, 2011, 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):

	Aggregate notional amount	Weighted average variable rate	Weighted average fixed rate
Interest rate swaps, fair value hedges	$ 1,400	3.7%	5.1%
Interest rate swaps, cash flow hedges	455	0.6%	2.3%

At December 31, 2011, the aggregate notional amounts associated with our cross-currency derivatives designated as hedging instruments were as follows (in millions, except weighted average interest rates):

	Pay		Receive	
	USD-denominated notional amount	Weighted average fixed rate	NOK-denominated notional amount	Weighted average fixed rate
Cross-currency swaps, cash flow hedges	$ 102	8.9%	NOK 560	11%

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

		December 31,	
	Balance sheet classification	2011	2010
Interest rate swaps, fair value hedges	Other current assets	$ 5	$ 4
Interest rate swaps, fair value hedges	Other assets	31	17
Interest rate swaps, cash flow hedges	Other long-term liabilities	16	13
Cross-currency swaps, cash flow hedges	Other long-term liabilities	7	—

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

	Statement of operations classification	Year ended December 31, 2011	2010
Loss associated with effective portion	Interest expense, net of amounts capitalized	$ 11	$ 12

Derivatives not designated as hedging instruments—In connection with our acquisition of Aker Drilling, we assumed certain interest rate swaps that are not designated as hedging instruments. At December 31, 2011, the aggregate notional amounts and the weighted average interest rates associated with our derivatives not designated as hedging instruments were as follows (in millions, except weighted average interest rates):

	Aggregate notional amount	Weighted average variable rate	Weighted average fixed rate
Interest rate swaps not designated as hedging instruments	$ 305	0.5%	4.2%

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, 2011	2010
Interest rate swaps not designated as hedging instruments	Other long-term liabilities	$ 15	$ —

On August 17, 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 kroner exchange rate. The aggregate notional amount and the exchange rate associated with the forward exchange contract were as follows (in millions, except exchange rate):

	Aggregate notional amount Pay	Receive	Exchange rate
Forward exchange contract	$ 1,120	NOK 6,051	5.4005

During the year ended December 31, 2011, we settled the full amount of the forward exchange contract, and, as a result, we recognized a loss on foreign exchange in the amount of $78 million, recorded in other, net.

Additionally, in connection with our acquisition of Aker Drilling, we assumed other derivative instruments, which were not designated as hedging instruments for accounting purposes. On the acquisition date, we recognized a liability for these undesignated derivative instruments, measured at fair value, in the aggregate amount of $12 million. In October 2011, we terminated these other undesignated derivative instruments for an aggregate cash payment of $15 million and recognized a loss on the terminations in the amount of $3 million, recorded in other, net.

Note 14—Postemployment Benefit Plans

Defined benefit pension plans and other postretirement employee benefit plans

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

We maintain a defined benefit plan in the U.K. (the "U.K. Plan") covering certain current and former employees in the U.K. We also provide several funded defined benefit plans, primarily group pension schemes with life insurance companies, and two unfunded plans, covering our eligible Norway employees and former employees (the "Norway Plans"). In connection with our acquisition of Aker Drilling, we assumed the obligations under three funded defined benefit plans, under group pension schemes with life insurance companies, covering eligible Norway employees (the "Assumed 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, the Assumed 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.

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

	December 31, 2011			December 31, 2010		
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans
Discount rate	4.66%	4.90%	4.28%	5.48%	5.81%	4.92%
Compensation trend rate	4.22%	4.30%	n/a	4.24%	4.65%	n/a

The following were the weighted-average assumptions used to determine net periodic benefit costs:

	Year ended December 31, 2011			Year ended December 31, 2010			Year ended December 31, 2009		
	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans	U.S. Plans	Non-U.S. Plans	OPEB Plans
Discount rate	5.49%	5.73%	4.94%	5.86%	5.67%	5.51%	5.41%	6.06%	5.34%
Expected rate of return	8.49%	6.42%	n/a	8.49%	6.65%	n/a	8.50%	6.59%	n/a
Compensation trend rate	4.24%	4.62%	n/a	4.21%	4.77%	n/a	4.21%	4.55%	n/a
Health care cost trend rate									
-initial	n/a	n/a	8.08%	n/a	n/a	8.00%	n/a	n/a	8.99%
-ultimate	n/a	n/a	5.00%	n/a	n/a	5.00%	n/a	n/a	5.00%
-ultimate year	n/a	n/a	2018	n/a	n/a	2016	n/a	n/a	2016

"n/a" means not applicable.

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

	Year ended December 31, 2011				Year ended December 31, 2010			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Change in projected benefit obligation								
Projected benefit obligation, beginning of period	$ 1,068	$ 374	$ 56	$ 1,498	$ 932	$ 403	$ 54	$ 1,389
Assumed projected benefit obligation	—	17	—	17	—	—	—	—
Actuarial (gains) losses, net	128	24	(3)	149	89	(46)	2	45
Service cost	43	21	1	65	42	20	1	63
Interest cost	58	22	3	83	54	20	3	77
Foreign currency exchange rate	—	(1)	—	(1)	—	(13)	—	(13)
Benefits paid	(37)	(12)	(5)	(54)	(51)	(14)	(5)	(70)
Participant contributions	—	2	1	3	—	2	1	3
Special termination benefits	—	—	—	—	3	—	—	3
Settlements and curtailments	—	—	—	—	(1)	2	—	1
Projected benefit obligation, end of period	1,260	447	53	1,760	1,068	374	56	1,498
Change in plan assets								
Fair value of plan assets, beginning of period	697	332	—	1,029	594	281	—	875
Fair value of acquired plan assets	—	9	—	9	—	—	—	—
Actual return on plan assets	39	(8)	—	31	85	29	—	114
Foreign currency exchange rate changes	—	2	—	2	—	(11)	—	(11)
Employer contributions	70	29	4	103	69	45	4	118
Participant contributions	—	2	1	3	—	2	1	3
Benefits paid	(37)	(12)	(5)	(54)	(51)	(14)	(5)	(70)
Settlement and curtailments	—	(3)	—	(3)	—	—	—	—
Fair value of plan assets, end of period	769	351	—	1,120	697	332	—	1,029
Funded status, end of period	$ (491)	$ (96)	$ (53)	$ (640)	$ (371)	$ (42)	$ (56)	$ (469)
Balance sheet classification, end of period:								
Pension asset, non-current	$ —	$ —	$ —	$ —	$ —	$ (8)	$ —	$ (8)
Accrued pension liability, current	3	5	3	11	3	2	4	9
Accrued pension liability, non-current	488	91	50	629	368	48	52	468
Accumulated other comprehensive income (loss) (a)	(437)	(111)	(2)	(550)	(308)	(61)	(2)	(371)

(a) Amounts are before income tax effect.

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

	December 31, 2011				December 31, 2010			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Projected benefit obligation	$ 1,260	$ 447	$ 53	$ 1,760	$ 1,068	$ 290	$ 56	$ 1,414
Fair value of plan assets	769	351	—	1,120	697	248	—	945

The accumulated benefit obligation for all defined benefit pension plans was $1.5 billion and $1.3 billion at December 31, 2011 and 2010, respectively. The aggregate accumulated benefit obligation and fair value of plan assets for plans with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	December 31, 2011				December 31, 2010			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Accumulated benefit obligation	$ 1,083	$ 288	$ 53	$ 1,424	$ 921	$ 269	$ 56	$ 1,246
Fair value of plan assets	769	254	—	1,023	697	248	—	945

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

As of December 31, 2011 and 2010, the weighted-average target and actual allocations of the investments for our funded Transocean Plans were as follows:

	Target allocation		Actual allocation at December 31, 2011		2010	
	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans	U.S. Plans	Non-U.S. Plans
Equity securities	65 %	51 %	64 %	47 %	65 %	53 %
Fixed income securities	35 %	14 %	36 %	12 %	34 %	10 %
Other investments	— %	35 %	— %	41 %	1 %	37 %
Total	100 %	100 %	100 %	100 %	100 %	100 %

As of December 31, 2011, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2011								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Equity securities:									
U.S.	$ 395	$ —	$ 395	$ —	$ 29	$ 29	$ 395	$ 29	$ 424
Non-U.S.	91	—	91	2	137	139	93	137	230
Total equity securities	486	—	486	2	166	168	488	166	654
Fixed income securities:									
U.S. government	52	—	52	—	—	—	52	—	52
U.S. corporate	9	—	9	—	—	—	9	—	9
Non-U.S. government	178	—	178	—	43	43	178	43	221
Non-U.S. corporate	39	—	39	—	—	—	39	—	39
Total fixed income securities	278	—	278	—	43	43	278	43	321
Other investments:									
Cash	3	38	41	—	—	—	3	38	41
Property	—	—	—	—	8	8	—	8	8
Investment contracts	—	—	—	—	96	96	—	96	96
Total other investments	3	38	41	—	104	104	3	142	145
Total investments	$ 767	$ 38	$ 805	$ 2	$ 313	$ 315	$ 769	$ 351	$ 1,120

As of December 31, 2010, the investments for our funded Transocean Plans were categorized as follows (in millions):

	December 31, 2010								
	Significant observable inputs			Significant other observable inputs			Total		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Equity securities:									
U.S.	$ 359	$ —	$ 359	$ —	$ 28	$ 28	$ 359	$ 28	$ 387
Non-U.S.	91	—	91	2	148	150	93	148	241
Total equity securities	450	—	450	2	176	178	452	176	628
Fixed income securities:									
U.S. government	59	—	59	—	—	—	59	—	59
U.S. corporate	175	—	175	—	—	—	175	—	175
Non-U.S. government	—	—	—	—	34	34	—	34	34
Non-U.S. corporate	7	—	7	—	—	—	7	—	7
Total fixed income securities	241	—	241	—	34	34	241	34	275
Other investments:									
Cash	4	31	35	—	—	—	4	31	35
Property	—	—	—	—	7	7	—	7	7
Investment contracts	—	—	—	—	84	84	—	84	84
Total other investments	4	31	35	—	91	91	4	122	126
Total investments	$ 695	$ 31	$ 726	$ 2	$ 301	$ 303	$ 697	$ 332	$ 1,029

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

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

	Year ended December 31, 2011			Year ended December 31, 2010			Year ended December 31, 2009		
	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans	U.S. Plans	Non-U.S. Plans	Transocean Plans
Service cost	$ 43	$ 21	$ 64	$ 42	$ 20	$ 62	$ 44	$ 18	$ 62
Interest cost	58	22	80	54	20	74	50	17	67
Expected return on plan assets	(63)	(23)	(86)	(58)	(17)	(75)	(55)	(16)	(71)
Settlements and curtailments	2	1	3	5	3	8	4	2	6
Special termination benefits	—	—	—	3	—	3	—	—	—
Actuarial losses, net	23	4	27	13	4	17	18	2	20
Prior service cost (credit), net	(1)	—	(1)	(1)	—	(1)	(1)	1	—
Transition obligation, net	—	—	—	—	1	1	—	—	—
Net periodic benefit costs	$ 62	$ 25	$ 87	$ 58	$ 31	$ 89	$ 60	$ 24	$ 84

For the OPEB Plans, the combined components of net periodic benefit costs, including service cost, interest cost, amortization of prior service cost and recognized net actuarial losses were $1 million, $2 million and $3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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

	December 31, 2011				December 31, 2010			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ 447	$ 113	$ 4	$ 564	$ 319	$ 52	$ 7	$ 378
Prior service cost (credit), net	(10)	—	(2)	(12)	(11)	8	(5)	(8)
Transition obligation, net	—	(2)	—	(2)	—	1	—	1
Total	$ 437	$ 111	$ 2	$ 550	$ 308	$ 61	$ 2	$ 371

The following table presents the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit costs during the year ending December 31, 2012 (in millions):

	Year ending December 31, 2012			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Actuarial loss, net	$ 39	$ 4	$ —	$ 43
Prior service cost (credit), net	(1)	—	(1)	(2)
Transition obligation, net	—	—	—	—
Total amount expected to be recognized	$ 38	$ 4	$ (1)	$ 41

Funding contributions—During the years ended December 31, 2011, 2010 and 2009, we contributed $103 million, $118 million and $73 million, respectively, to the Transocean Plans and the OPEB Plans using our cash flows from operations. For the year ending December 31, 2012, we expect to contribute $145 million to the Transocean Plans, and we expect to fund benefit payments of approximately $3 million for the OPEB Plans as costs are incurred.

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

	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Years ending December 31,				
2012	$ 41	$ 10	$ 3	$ 54
2013	44	10	3	57
2014	47	10	3	60
2015	50	9	4	63
2016	54	9	4	67
2017-2021	319	62	20	401

Defined contribution plans

We sponsor three defined contribution plans, including (1) one qualified defined contribution savings plan covering certain employees working in the U.S. (the “U.S. Savings Plan”), (2) one defined contribution savings plan covering certain employees working outside the U.S. and U.K. (the “Non-U.S. Savings Plan”), and (3) one defined contribution pension plan that covers certain employees working outside the U.S. (the “Non-U.S. Pension Plan”).

For the U.S. Savings Plan and the Non-U.S. Savings Plan, we make a matching contribution of up to 6.0 percent of each covered employee’s base salary, based on the employee’s contribution to the plan. For the Non-U.S. Pension Plan, we contribute between 4.5 percent and 6.5 percent of each covered employee’s base salary, based on the employee’s years of eligible service. We recorded approximately $82 million, $69 million and $67 million of expense related to our defined contribution plans for the years ended December 31, 2011, 2010 and 2009, respectively.

Note 15—Commitments and Contingencies

Lease obligations

We have operating lease commitments expiring at various dates, principally for real estate, office space and office equipment. In August 2009, we accepted delivery of *Petrobras 10000*, an asset held under a capital lease through August 2029. Additionally, in March 2010, we acquired *GSF Explorer*, an asset formerly held under a capital lease, in exchange for a cash payment terminating the capital lease obligation in the amount of $15 million. Rental expenses for all leases, including leases with terms of less than one year, was approximately $169 million, $98 million and $99 million for the years ended December 31, 2011, 2010 and 2009, respectively. As of December 31, 2011, future minimum rental payments related to noncancellable operating leases and the capital lease were as follows (in millions):

	Capital lease	Operating leases
Years ending December 31,		
2012	$ 66	$ 39
2013	72	39
2014	72	27
2015	72	22
2016	73	21
Thereafter	918	91
Total future minimum rental payment	$ 1,273	$ 239
Less amount representing imputed interest	(597)	
Present value of future minimum rental payments under capital leases	676	
Less current portion included in debt due within one year	(17)	
Long-term capital lease obligation	$ 659	

The following were the aggregate carrying amount of our assets held under capital lease as of December 31, 2011 and 2010, respectively (in millions):

	December 31, 2011	December 31, 2010
Property and equipment, cost	$ 742	$ 740
Accumulated depreciation	(44)	(24)
Property and equipment, net	$ 698	$ 716

Depreciation expense associated with our assets held under capital lease was $20 million, $23 million and $14 million for the years ended December 31, 2011, 2010 and 2009, respectively. Depreciation expense for *GSF Explorer* is included only through the date of our acquisition of the rig in March 2010.

Purchase obligations

At December 31, 2011, our purchase obligations, primarily related to our newbuilds, were as follows (in millions):

	Purchase obligations
Years ending December 31,	
2012	$ 311
2013	592
2014	408
2015	—
2016	—
Thereafter	—
Total	$ 1,311

Macondo well incident

Overview—On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig. Eleven persons were declared dead and others were injured as a result of the incident. At the time of the explosion, *Deepwater Horizon* was located approximately 41 miles off the coast of Louisiana in Mississippi Canyon Block 252 and was contracted to BP America Production Co.

Trial is currently scheduled to commence on March 5, 2012. There can be no assurance as to the outcome of the trial, that the trial will proceed according to the proposed schedule, 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 the trial, or a timing or terms of any such settlement.

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. As of December 31, 2011, we have recognized a liability for such loss contingencies in the amount of $1.2 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. As of December 31, 2011, we have also recognized an asset of $220 million associated with the portion of our estimated losses that we believe is recoverable from insurance. Although we have available policy limits that could result in additional amounts recoverable from insurance, we are not currently able to estimate the amount of such additional recoverable amounts. Our estimates involve a significant amount of judgment. As a result of new information or future developments, some of which could occur very soon, 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. As of December 31, 2010, the amount of the estimated liability was $135 million, and the estimated recoverable amount was $94 million.

In April 2011, several defendants in the Macondo well litigation before the Multi-District Litigation Panel (the "MDL") filed cross-claims or third-party claims against us and certain of our subsidiaries, and other defendants. BP filed a claim seeking contribution under the Oil Pollution Act of 1990 ("OPA") and maritime law, subrogation and claimed breach of contract, unseaworthiness, negligence and gross negligence. BP also sought a declaration that it is not liable in contribution, indemnification, or otherwise to us. Anadarko Petroleum Corporation ("Anadarko"), which owns a 25 percent non-operating interest in the Macondo well, asserted claims of negligence, gross negligence, and willful misconduct and is seeking indemnity under state and maritime law and contribution under maritime and state law as well as OPA. MOEX Offshore 2007 LLC ("MOEX"), which owns a 10 percent non-operating interest in the Macondo well, filed claims of negligence under state and maritime law, gross negligence under state law, gross negligence and willful misconduct under maritime law and is seeking indemnity under state and maritime law and contribution under maritime law and OPA. Cameron International Corporation ("Cameron"), the manufacturer and designer of the blowout preventer, asserted multiple claims for contractual indemnity and declarations regarding contractual obligations under various contracts and quotes and is also seeking non-contractual indemnity and contribution under maritime law and OPA. Halliburton Company ("Halliburton"), which provided cementing and mud-logging services to the operator, filed a claim seeking contribution and indemnity under maritime law, contractual indemnity and alleging negligence and gross negligence. Additionally, certain other third parties filed claims for indemnity and contribution.

On April 20, 2011, we filed cross-claims and counter-claims against BP, Halliburton, Cameron, Anadarko, MOEX, certain of these parties' affiliates, the U.S. and certain other third parties. We seek indemnity, contribution (including contribution under OPA), and subrogation under OPA, and we have asserted claims for breach of warranty of workmanlike performance, strict liability for manufacturing and design defect, breach of express contract, and damages for the difference between the fair market value of *Deepwater Horizon* and the amount received from insurance proceeds. Additionally, we have preserved our right to arbitration under our contract with BP in each of the relevant filings. With regard to the U.S., we are not seeking recovery of monetary damages, but rather a declaration regarding relative fault and contribution via credit, setoff, or recoupment.

The U.S. District Court, Eastern District of Louisiana (the "MDL Court") has issued an order outlining the trial plan, which will proceed in three phases. The first phase will focus on issues arising out of the conduct of various parties, relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on *Deepwater Horizon* on April 20, 2010, the sinking of *Deepwater Horizon* on April 22, 2010, and the initiation of the release of oil during those time periods. The second phase will address conduct relating 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 that time period. The third, and final, phase will involve consideration of issues relating to containing oil discharged by controlled burning, application of dispersants, use of booms, skimming and other methods, as well as issues pertaining to the migration paths and end locations of oil released.

Notices of alleged non-compliance—The final Joint Investigation Team report was issued on September 14, 2011. Subsequently, the Department of the Interior's Bureau of Safety and Environmental Enforcement issued four notices of alleged non-compliance with regulatory requirements to us on October 12, 2011. While we cannot predict or provide assurance as to the full outcome of these citations, they could result in the assessment of civil penalties. Our appeal is stayed by mutual agreement with the Department of Interior until a ruling is issued in the MDL.

Insurance coverage—In May 2010, we received notice from BP maintaining that it believes that it is entitled to additional insured status under our excess liability insurance program. In response, many of our insurers filed declaratory judgment actions in the Houston Division of the U.S. District Court for the Southern District of Texas in May 2010 seeking a judgment declaring that they have limited additional insured obligation to the operator. Our insurers have also received notices from Anadarko and MOEX advising of their intent to preserve any rights they may have to our insurance policies as an additional insured under the drilling contract. We, Anadarko and MOEX each have entered into the declaratory judgment actions. The actions have been transferred to the MDL for discovery purposes in the U.S. District Court, Eastern District of Louisiana. On November 15, 2011, the court ruled that coverage rights are limited to the scope of Transocean's indemnity of BP in the drilling contract. Proposed final judgments have been submitted to and are under consideration by the court. The court's ruling may be appealed.

At the time of the Macondo well incident, our excess liability insurance program offered aggregate insurance coverage of $950 million, exclusive of a $15 million deductible and a $50 million self-insured layer through our wholly-owned captive insurance subsidiary. This excess liability insurance coverage consisted of a first and a second layer of $150 million each, a third and fourth layer of $200 million each and a fifth layer of $250 million. The $250 million fifth layer contains different contractual terms, compared to the first four layers, with regard to additional insured status, such that we believe with reasonable certainty that BP, Anadarko and MOEX do not have contractual right to additional insured status under that layer of our insurance program.

Additionally, our first layer of excess insurers 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. A protocol has been executed by the parties to the suits, and claims have been submitted to the court for review. The parties to the interpleaders have agreed to a protocol to facilitate the reimbursement and funding of settlements of personal injury and fatality claims of our crew and vendors using insurance funds. To date, no payments have yet been received.

Litigation—As of December 31, 2011, 349 actions or claims were pending against us and certain of our subsidiaries, along with other unaffiliated defendants, in state and federal courts. Additionally, government agencies have initiated investigations into the Macondo well incident. We have categorized below the nature of the legal actions or claims. We are evaluating all claims and intend to vigorously defend any claims and pursue any and all defenses available. In addition, we believe we are entitled to contractual defense and indemnity for all wrongful death and personal injury claims made by non-employees and third-party subcontractors' employees as well as all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See "—Contractual indemnity."

Wrongful death and personal injury—As of December 31, 2011, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in 34 complaints that were pending in state and federal courts in Louisiana and Texas involving multiple plaintiffs that allege wrongful death and other personal injuries arising out of the Macondo well incident. Per the order of the MDL, these claims have been centralized for discovery purposes in the U.S. District Court, Eastern District of Louisiana. The complaints generally allege negligence and seek awards of unspecified economic damages and punitive damages. BP, MI-SWACO, Weatherford Ltd. and Cameron International Corporation and certain of their affiliates, have, based on contractual arrangements, also made indemnity demands upon us with respect to personal injury and wrongful death claims asserted by our employees or representatives of our employees against these entities. See "—Contractual indemnity."

Economic loss—As of December 31, 2011, we and one or more of our subsidiaries were named, along with other unaffiliated defendants, in 114 individual complaints as well as 184 putative class-action complaints that were pending in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Florida and possibly other courts. The complaints generally allege, among other things, potential economic losses as a result of environmental pollution arising out of the Macondo well incident and are based primarily on the OPA and state OPA analogues. The plaintiffs are generally seeking awards of unspecified economic, compensatory and punitive damages, as well as injunctive relief. See "—Contractual indemnity."

Federal securities claims—Two federal securities law class actions are currently pending in the U.S. District Court, Southern District of New York, naming us and certain of our officers and directors as defendants. One of these actions generally allege violations of Section 10(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), Rule 10b-5 promulgated under the Exchange Act and Section 20(a) of the Exchange Act in connection with the Macondo well incident. The plaintiffs are generally seeking awards of unspecified economic damages, including damages resulting from the decline in our stock price after the Macondo well incident. The other action was filed by a former GlobalSantaFe shareholder, alleging that the proxy statement related to our shareholder meeting in connection with our merger with GlobalSantaFe violated Section 14(a) of the Exchange Act, Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The plaintiff claims that GlobalSantaFe shareholders received inadequate consideration for their shares as a result of the alleged violations and seeks rescission and compensatory damages. The defendants have filed motions to dismiss each of these claims, and the plaintiffs have responded. The motions have been fully briefed and are pending rulings by the courts.

Other federal statutes—Several of the claimants have made assertions under the statutes, including the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Air Act, the Comprehensive Environmental Response Compensation and Liability Act and the Emergency Planning and Community Right-to-Know Act.

Shareholder derivative claims—In June 2010, two shareholder derivative suits were filed by our shareholders naming us as a nominal defendant and certain of our officers and directors as defendants in the District Courts of the State of Texas. The first case generally alleges breach of fiduciary duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets in connection with the Macondo well incident and the other generally alleges breach of fiduciary duty, unjust enrichment and waste of corporate assets in connection with the Macondo well incident. The plaintiffs are generally seeking, on behalf of us, restitution and disgorgement of all profits, benefits and other compensation from the defendants. Under current schedule orders, an amended consolidated complaint must be filed by the plaintiffs by March 5, 2012.

Government claims—On December 15, 2010, the U.S. Department of Justice ("DOJ") filed a civil lawsuit against us and other unaffiliated defendants. The complaint alleges violations under OPA and the Clean Water Act, including claims for per barrel civil penalties of up to $1,100 per barrel or up to $4,300 per barrel if gross negligence or willful misconduct is established, and the DOJ reserved its rights to amend the complaint to add new claims and defendants. The U.S. government has estimated that up to 4.1 million barrels of oil were discharged and subject to penalties. The complaint asserts that all defendants named 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 severely liable under OPA, and liable for civil penalties under the Clean Water Act, for all of the discharges from Macondo well on the theory that discharges not only came from the well but also from the blowout preventer and riser, appurtenances of *Deepwater Horizon*. See Note 28—Subsequent Events.

In addition to the civil complaint, the DOJ served us with civil investigative demands on December 8, 2010. These demands were part of an investigation by the DOJ to determine if we made false claims, or false statements in support of claims, in connection with the operator's acquisition of the leasehold interest in the Mississippi Canyon Block 252, Gulf of Mexico and drilling operations on *Deepwater Horizon.*

The DOJ is also conducting a criminal investigation into the Macondo well incident. On March 7, 2011, the DOJ announced the formation of a new task force to lead the criminal investigation. The task force served us with informal requests for documents in March 2011, and a grand jury issued a subpoena requesting documents from us on April 13, 2011. We have had a number of communications with the task force since that time, and the task force has made informal requests for additional information from us from time to time. The task force is investigating possible violations by us and certain unaffiliated parties of the Clean Water Act, the Migratory Bird Treaty Act, the Refuse Act, the Endangered Species Act, and the Seaman's Manslaughter Act, among other federal statues, and possible criminal liabilities including fines under those statues and under the Alternative Fines Act. Under the Alternatives Fines Act, a corporate defendant convicted of a criminal offense may be subject to a fine in the amount of twice the gross pecuniary loss suffered by third parties as a result of the offense. If we are charged with or convicted of certain criminal environmental offenses, we may be subject to suspension or debarment as a contractor or subcontractor on certain government contracts, including leases.

In June 2010, the Louisiana Department of Environmental Quality (the "LDEQ") issued a consolidated compliance order and notice of potential penalty to us and certain of our subsidiaries asking us to eliminate and remediate discharges of oil and other pollutants into waters and property located in the State of Louisiana, and to submit a plan and report in response to the order. In October 2010, the LDEQ rescinded its enforcement actions against us and our subsidiaries but reserved its rights to seek civil penalties for future violations of the Louisiana Environmental Quality Act.

In September 2010, the State of Louisiana filed a declaratory judgment seeking to designate us as a responsible party under OPA and the Louisiana Oil Spill Prevention and Response Act for the discharges emanating from the Macondo well.

Additionally, suits have been filed by the State of Alabama and the cities of Greenville, Evergreen, Georgiana and McKenzie, Alabama in the U.S. District Court, Middle District of Alabama; the Mexican States of Veracruz, Quintana Roo and Tamaulipas in the U.S. District Court, Western District of Texas; and the City of Panama City Beach, Florida in the U.S. District Court, Northern District of Florida. Suits were also filed by the City of New Orleans, by and on behalf of multiple Parishes, and by or on behalf of the Town of Grand Isle, Grand Isle Independent Levee District, the Town of Jean Lafitte, the Lafitte Area Independent Levee District, the City of Gretna, the City of Westwego, and the City of Harahan in the U.S. District Court, Eastern District of Louisiana. Additional suits were filed by or on behalf of other Parishes in the respective Parish courts and were removed to federal court. A local government master complaint also was filed in which cities, municipalities, and other local government entities can and have joined. Generally, these governmental entities allege economic losses under OPA and other statutory environmental state claims and also assert various common law state claims. The claims have been centralized in the MDL and will proceed in accordance with the MDL scheduling order. The city of Panama City Beach's claim was voluntarily dismissed.

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

The Mexican States' OPA claims were dismissed for failure to demonstrate that recovery under OPA was authorized by treaty or executive agreement. This ruling may be appealed.

By letter dated May 5, 2010, the Attorneys General of the five Gulf Coast states of Alabama, Florida, Louisiana, Mississippi and Texas informed us that they intend to seek recovery of pollution clean-up costs and related damages arising from the Macondo well incident. In addition, by letter dated June 21, 2010, the Attorneys General of the 11 Atlantic Coast states of Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Rhode Island and South Carolina informed us that their states have not sustained any damage from the Macondo well incident but they would like assurances that we will be responsible financially if damages are sustained. We responded to each letter from the Attorneys General and indicated that we intend to fulfill our obligations as a responsible party for any discharge of oil from *Deepwater Horizon* on or above the surface of the water, and we assume that the operator will similarly fulfill its obligations under OPA for discharges from the undersea well. Other than the lawsuits filed by the states discussed above, no further requests have been made or actions taken subsequent to the initial communication.

Wreck removal—By letter dated December 6, 2010, the Coast Guard requested us to formulate and submit a comprehensive oil removal plan to remove any diesel fuel contained in the sponsons and fuel tanks that can be recovered from *Deepwater Horizon.* We have conducted a survey of the rig wreckage and have confirmed that no diesel fuel remains on the rig. We have insurance coverage for wreck removal for up to 25 percent of *Deepwater Horizon's* insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our remaining excess liability limits.

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

Although we believe we are entitled to contractual defense and indemnity, given the potential amounts involved in connection with the Macondo well incident, the operator has sought to avoid its indemnification obligations. In particular, the operator, in response to our request for indemnification, has generally reserved all of its rights and stated that it could not at this time conclude that it is obligated to indemnify us. In doing so, the operator has asserted that the facts are not sufficiently developed to determine who is responsible and has cited a variety of possible legal theories based upon the contract and facts still to be developed. We believe this reservation of rights is without justification and that the operator is required to honor its indemnification obligations contained in our contract and described above.

In April 2011, BP filed a claim seeking a declaration that it is not liable to us in contribution, indemnification, or otherwise. On November 1, 2011, we filed a motion for partial summary judgment seeking enforcement of the indemnity obligations for pollution and civil fines and penalties contained in the drilling contract with BP. See Note 28—Subsequent Events.

Other legal proceedings

Brazil Frade field incident—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 Frade field with *Sedco 706*. The release was ultimately controlled and the well was plugged. The oil released is in the process of being contained by Chevron.

On or about December 13, 2011, a federal prosecutor in the town of Campos in Rio de Janeiro State filed a civil public action against Chevron and us seeking 20.0 billion Brazilian reals, equivalent to approximately $11.0 billion, and seeking a preliminary and permanent injunction preventing Chevron and us from operating in Brazil. The prosecutor amended the requested injunction on December 15, 2011, to seek 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. The complaint has not been served on us.

On December 21, 2011, a federal police marshal investigating the release filed a report with the federal court in Rio de Janeiro State recommending the indictment of Chevron, us, and 17 individuals, five of which are our employees. The report recommended indictment on four counts, three alleging environmental offenses and one alleging false statements by Chevron in connection with its cleanup efforts. The federal court in Rio de Janeiro State has forwarded the report to the federal court in Campos for a decision on the proper jurisdiction for the matter.

The drilling services and charter contracts between us and Chevron provides, among other things, for Chevron to indemnify and defend us for claims based on pollution or contamination originating from below the surface of the water, including claims for control or removal or property loss or damage, including but not limited to third-party claims and liabilities, with an excludable amount of $250,000 per occurrence if the claim arises from our negligence.

We believe that we have valid defenses to the threatened civil and criminal claims by the federal prosecutor and intend to defend vigorously against any claims that are brought based on the incident. We also intend to pursue indemnity rights under our contracts with Chevron.

Asbestos litigation—In 2004, several of our subsidiaries were named, along with numerous other unaffiliated defendants, in 21 complaints filed on behalf of 769 plaintiffs in the Circuit Courts of the State of Mississippi and which claimed injuries arising out of exposure to asbestos allegedly contained in drilling mud during these plaintiffs' employment in drilling activities between 1965 and 1986. Each individual plaintiff was subsequently required to file a separate lawsuit, and the original 21 multi-plaintiff complaints were then dismissed by the Circuit Courts. The amended complaints resulted in one of our subsidiaries being named as a direct defendant in seven cases. We have or may have an indirect interest in an additional 12 cases. The complaints generally allege that the defendants used or manufactured asbestos-containing drilling mud additives for use in connection with drilling operations and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. The plaintiffs generally seek awards of unspecified compensatory and punitive damages. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling-related products that contained asbestos. All of these cases are being governed for discovery and trial setting by a single Case Management Order entered by a Special Master appointed by the court to reside over all the cases, and none of the seven cases in which we are a named defendant have been scheduled for trial or pre-trial discovery. The preliminary information available on these claims is not sufficient to determine if there is an identifiable period for alleged exposure to asbestos, whether any asbestos exposure in fact occurred, the vessels potentially involved in the claims, or the basis on which the plaintiffs would support claims that their injuries were related to exposure to asbestos. However, the initial evidence available would suggest that we would have significant defenses to liability and damages. None of our companies have manufactured or distributed drilling mud or additives for same, and the handling of such additives by one of our employees would be a relatively infrequent occurrence that likely would have involved a non-asbestos product. In 2011, the Special Master issued a ruling that a Jones Act employer defendant, such as us, cannot be sued for punitive damages, and we expect this ruling to apply to each of our seven cases. To date, seven of the 769 cases have gone to trial against defendants who allegedly manufactured or distributed drilling mud additives. None of these cases have involved an individual Jones Act employer and we have not been a defendant in any of these cases. Two of the cases resulted in defense verdicts and one case ended with a hung jury. Four cases resulted in verdicts for the plaintiff. Because the jury awarded punitive damages, two of these cases resulted in a substantial verdict in favor of the plaintiff, however both of these verdicts have since been vacated by the trial court. One was vacated on the basis that the plaintiff failed to meet its burden of proof. While the court's decision is consistent with our general evaluation of the strength of these cases, it is currently being reviewed on appeal. The second plaintiff verdict was vacated because the presiding judge was removed from hearing any asbestos cases due to a conflict of interest. The two remaining plaintiff verdicts are under appeal by the defendants. We intend to defend these lawsuits vigorously, although there can be no assurance as to the ultimate outcome. We historically have maintained broad liability insurance, although we are not certain whether insurance will cover the liabilities, if any, arising out of these claims. Based on our evaluation of the exposure to date, we do not expect the liability, if any, resulting from these claims to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

One of our subsidiaries was involved in lawsuits arising out of the subsidiary's involvement in the design, construction and refurbishment of major industrial complexes. The operating assets of the subsidiary were sold and its operations discontinued in 1989, and the subsidiary has no remaining assets other than the insurance policies involved in its litigation, with its insurers and, either directly or indirectly as the beneficiary of a qualified settlement fund, funding from settlements with insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers, and funds received from the commutation of certain insurance policies. The subsidiary has been named as a defendant, along with numerous other companies, in lawsuits alleging bodily injury or personal injury as a result of exposure to asbestos. As of December 31, 2011, the subsidiary was a defendant in approximately 950 lawsuits. Some of these lawsuits include multiple plaintiffs and we estimate that there are approximately 2,114 plaintiffs in these lawsuits. For many of these lawsuits, we have not been provided with sufficient information from the plaintiffs to determine whether all or some of the plaintiffs have claims against the subsidiary, the basis of any such claims, or the nature of their alleged injuries. The first of the asbestos-related lawsuits was filed against this subsidiary in 1990. Through December 31, 2011, the amounts expended to resolve claims, including both defense fees and expenses and settlement costs, have not been material, all known deductibles have been satisfied or are inapplicable, and the subsidiary's defense fees and expenses and costs of settlement have been met by insurance made available to the subsidiary. The subsidiary continues to be named as a defendant in additional lawsuits, and we cannot predict the number of additional cases in which it may be named a defendant nor can we predict the potential costs to resolve such additional cases or to resolve the pending cases. However, the subsidiary has in excess of $1.0 billion in insurance limits potentially available to the subsidiary. Although not all of the policies may be fully available due to the insolvency of certain insurers, we believe that the subsidiary will have sufficient funding from settlements and claims payments from insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers to respond to these claims. While we cannot predict or provide assurance as to the final outcome of these matters, we do not believe that the current value of the claims where we have been identified will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Rio de Janeiro tax assessment—In the third quarter of 2006, we received tax assessments of approximately $187 million from the state tax authorities of Rio de Janeiro in Brazil against one of our Brazilian subsidiaries for taxes on equipment imported into the state in connection with our operations. The assessments resulted from a preliminary finding by these authorities that our subsidiary's record keeping practices were deficient. We currently believe that the substantial majority of these assessments are without merit. We filed an initial response with the Rio de Janeiro tax authorities on September 9, 2006 refuting these additional tax assessments. In September 2007, we received confirmation from the state tax authorities that they believe the additional tax assessments are valid, and as a result, we filed an appeal on September 27, 2007 to the state Taxpayer's Council contesting these assessments. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Brazilian import license assessment—In the fourth quarter of 2010, one of our Brazilian subsidiaries received an assessment from the Brazilian federal tax authorities in Rio de Janeiro of approximately $235 million based upon the alleged failure to timely apply for import licenses for certain equipment and for allegedly providing improper information on import license applications. We responded to the assessment on December 22, 2010, and we currently believe that a substantial majority of the assessment is without merit. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other matters—We are involved in various tax matters and various regulatory matters. We are also involved in lawsuits relating to damage claims arising out of hurricanes Katrina and Rita, all of which are insured and which are not material to us. As of December 31, 2011, we were involved in a number of other lawsuits, including a dispute for municipal tax payments in Brazil and a dispute involving customs procedures in India, neither of which is material to us, and all of which have arisen in the ordinary course of our business. We do not expect the liability, if any, resulting from these other matters to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such other pending or threatened litigation. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

Other environmental matters

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

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

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

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

- the actual responsibility attributed to us and the other PRPs at the site;
- appropriate investigatory or remedial actions; and
- allocation of the costs of such activities among the PRPs and other site users.

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

- the volume and nature of material, if any, contributed to the site for which we are responsible;
- the number of other PRPs and their financial viability; and
- the remediation methods and technology to be used.

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

Contamination litigation

On July 11, 2005, one of our subsidiaries was served with a lawsuit filed on behalf of three landowners in Louisiana in the 12th Judicial District Court for the Parish of Avoyelles, State of Louisiana. The lawsuit named 19 other defendants, all of which were alleged to have contaminated the plaintiffs' property with naturally occurring radioactive material, produced water, drilling fluids, chlorides, hydrocarbons, heavy metals and other contaminants as a result of oil and gas exploration activities. Experts retained by the plaintiffs issued a report suggesting significant contamination in the area operated by the subsidiary and another codefendant, and claimed that over $300 million would be required to properly remediate the contamination. The experts retained by the defendants conducted their own investigation and concluded that the remediation costs would amount to no more than $2.5 million.

The plaintiffs and the codefendant threatened to add GlobalSantaFe as a defendant in the lawsuit under the "single business enterprise" doctrine contained in Louisiana law. The single business enterprise doctrine is similar to corporate veil piercing doctrines. On August 16, 2006, our subsidiary and its immediate parent company, each of which is an entity that no longer conducts operations or holds assets, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. Later that day, the plaintiffs dismissed our subsidiary from the lawsuit. Subsequently, the codefendant filed various motions in the lawsuit and in the Delaware bankruptcies attempting to assert alter ego and single business enterprise claims against GlobalSantaFe and two other subsidiaries in the lawsuit. The efforts to assert alter ego and single business enterprise theory claims against GlobalSantaFe were rejected by the Court in Avoyelles Parish, and the lawsuit against the other defendant went to trial on February 19, 2007. This lawsuit was resolved at trial with a settlement by the codefendant that included a $20 million payment and certain cleanup activities to be conducted by the codefendant. The codefendant further claimed to receive a right to continue to pursue the original plaintiff's claims.

The codefendant sought to dismiss the bankruptcies. In addition, the codefendant filed proofs of claim against both our subsidiary and its parent with regard to its claims arising out of the settlement of the lawsuit. On February 15, 2008, the bankruptcy court denied the codefendant's request to dismiss the bankruptcy case but modified the automatic stay to allow the codefendant to proceed on its claims against the debtors, our subsidiary and its parent, and their insurance companies. The codefendant subsequently filed suit against the debtors and certain of its insurers in the Court of Avoyelles Parish to determine their liability for the settlement. The denial of the motion to dismiss the bankruptcies was appealed. On appeal the bankruptcy cases were ordered to be dismissed, and the bankruptcies were dismissed on June 14, 2010.

On March 10, 2010, GlobalSantaFe and the two subsidiaries filed a declaratory judgment action in State District Court in Houston, Texas against the codefendant and the debtors seeking a declaration that GlobalSantaFe and the two subsidiaries had no liability under legal theories advanced by the codefendant. This action is currently stayed.

On March 11, 2010, the codefendant filed a motion for leave to amend the pending litigation in Avoyelles Parish to add GlobalSantaFe, Transocean Worldwide Inc., its successor and our wholly owned subsidiary, and one of the subsidiaries as well as various additional insurers. Leave to amend was granted and the amended petition was filed. An extension to respond for all purposes was agreed until April 28, 2010 for the debtors, GlobalSantaFe, Transocean Worldwide Inc. and the subsidiary. On April 28, 2010, GlobalSantaFe and its two subsidiaries filed various exceptions seeking dismissal of the Avoyelles Parish lawsuit, which have been denied. Subsequent to denial, GlobalSantaFe and its two subsidiaries filed supervisory writs with the Third Circuit Court of Appeals for the State of Louisiana.

On December 15, 2010, as permitted under the existing Case Management Order, GlobalSantaFe and various subsidiaries served third-party demands joining various insurers in the Avoyelles Parish lawsuit seeking insurance coverage for the claims brought against GlobalSantaFe and such subsidiaries. On January 27, 2011, one of the insurers filed pleadings removing the Avoyelles Parish lawsuit to the United States District Court for the Western District of Louisiana, Alexandria Division (the "Western District Action"). On February 3, 2011, GlobalSantaFe and the two subsidiaries filed motions to dismiss the Western District Action, which are now pending. A motion to remand was filed by the codefendant and a hearing on the motion was held on April 5, 2011. A report and recommendations were issued on April 25, 2011 by the magistrate in favor of granting the motion to remand. Objections to this report were filed with the district court. On September 27, 2011 the district court adopted the report and recommendations and remanded the matter to the state court in Avoyelles Parish. Separately, the removing insurer has filed an appeal of the United States Court of Appeals for the Fifth Circuit challenging the remand order and seeking to stay or enjoin the state court from proceeding until a determination of the appeal. The appeal is currently pending in the initial briefing state.

Subsequent to the remand, a scheduling order has been entered in the Avoyelles Parish lawsuit and a jury trial is set for September 17, 2012. In the interim, discovery is ongoing.

We believe that the legal theories advanced by the codefendant should not be applied against GlobalSantaFe or Transocean Worldwide Inc. Our subsidiary, its parent and GlobalSantaFe intend to continue to vigorously defend against any action taken in an attempt to impose liability against them under the theories discussed above or otherwise and believe they have good and valid defenses thereto. We do not believe that these claims will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Retained risk

Our hull and machinery and excess liability insurance program consists of commercial market and captive insurance policies. We periodically evaluate our insurance limits and self-insured retentions. As of December 31, 2011, the insured value of our drilling rig fleet was approximately $36.4 billion, excluding our rigs under construction.

Under the hull and machinery program, we generally maintain a $125 million per occurrence deductible, limited to a maximum of $250 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 coverage for wreck removal for an amount up to 25 percent of a rig's insured value, with any excess generally covered to the extent of our excess liability coverage described below. However, we generally retain the risk for all hull and machinery exposures for our Standard Jackups and swamp barge, which are self-insured through our wholly-owned captive insurance company.

We carry $793 million of commercial market excess liability coverage, exclusive of the deductibles and self-insured retention, noted below, which generally covers offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. Our excess liability coverage has (1) separate $10 million per occurrence deductibles on crew personal injury liability and on collision liability claims and (2) a separate $5 million per occurrence deductible 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, along with $157 million of the excess liability coverage, of which we have re-insured $25 million in the commercial market. In addition, we generally retain the risk for any liability losses in excess of $1.0 billion.

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 and CMI. 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 loss of revenue, unless it is contractually required, or for physical damage losses, including liability for wreck removal expenses, to our fleet caused by named windstorms in the U.S. Gulf of Mexico and war perils worldwide.

Letters of credit and surety bonds

We had letters of credit outstanding totaling $650 million and $595 million at December 31, 2011 and 2010, respectively, issued under various committed and uncommitted credit lines provided by several banks to guarantee various contract bidding, performance activities and customs obligations. Included in the letters of credit outstanding at December 31, 2011 and 2010 was a $60 million letter of credit issued for TPDI to satisfy its liquidity requirements under the TPDI Credit Facilities under an uncommitted credit facility that has been established by one of our subsidiaries (see Note 12—Debt).

As is customary in the contract drilling business, we also have various surety bonds in place that secure customs obligations relating to the importation of our rigs and certain performance and other obligations. Surety bonds outstanding totaled $12 million and $27 million at December 31, 2011 and 2010, respectively.

Note 16—Redeemable Noncontrolling Interest

Quantum owns the 50 percent interest in TPDI that is not owned by us and has the unilateral right to exchange its interest in TPDI for our shares or cash, at its election, at an amount based on an appraisal of the fair value of the drillships that are owned by TPDI, subject to certain adjustments. Accordingly, the carrying amount of Quantum's interest is presented as redeemable noncontrolling interest on our consolidated balance sheets. Changes in redeemable noncontrolling interest were as follows (in millions):

	Years ended December 31,		
	2011	2010	2009
Redeemable noncontrolling interest			
Balance, beginning of period	$ 25	$ —	$ —
Reclassification from noncontrolling interest	—	26	—
Net income attributable to noncontrolling interest (a)	94	13	—
Other comprehensive loss attributable to noncontrolling interest (a)	(3)	(14)	—
Balance, end of period	$ 116	$ 25	$ —

(a) The noncontrolling interest associated with TPDI was not redeemable during the year ended December 31, 2009.

Note 17—Shareholders' Equity

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

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. In May 2011, we recognized a distribution payable, recorded in other current liabilities, with a corresponding entry to additional paid-in capital. 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. At December 31, 2011, the carrying amount of the unpaid distribution payable was $278 million.

Shares held by subsidiary—In December 2008, we issued 16 million of our shares to one of our subsidiaries for future use to satisfy our obligations to deliver shares in connection with awards granted under our incentive plans or other rights to acquire our shares. At December 31, 2011 and 2010, our subsidiary held approximately 12 million shares and 13 million shares, respectively.

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 $3.7 billion, using an exchange rate of USD 1.00 to CHF 0.94 as of the close of trading on December 31, 2011. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program.

During the year ended December 31, 2011, we did not purchase any of our shares under our share repurchase program. During the year ended December 31, 2010, following the authorization by our board of directors, we repurchased 2,863,267 of our shares under our share repurchase program for an aggregate purchase price of CHF 257 million, equivalent to $240 million. At December 31, 2011 and 2010, we held 2,863,267 treasury shares purchased under our share repurchase program and recorded at cost.

Note 18—Share-Based Compensation Plans

Overview—We have (i) a long-term incentive plan (the "Long-Term Incentive Plan") for executives, key employees and outside directors under which awards can be granted in the form of stock options, restricted shares, deferred units, SARs and cash performance awards and (ii) other incentive plans under which awards are currently outstanding. Awards that may be granted under the Long-Term Incentive Plan include traditional time-vesting awards ("time-based awards") and awards that are earned based on the achievement of certain performance criteria ("performance-based awards") or market factors ("market-based awards"). Our executive compensation committee of our board of directors determines the terms and conditions of the awards granted under the Long-Term Incentive Plan. As of December 31, 2011, we had 36 million shares authorized and 15 million shares available to be granted under the Long-Term Incentive Plan.

Time-based awards typically vest either in three equal annual installments beginning on the first anniversary date of the grant or in an aggregate installment at the end of the stated vesting period. Performance-based and market-based awards are typically awarded subject to either a two-year or a three-year measurement period during which the number of options, shares or deferred units remains uncertain. At the end of the measurement period, the awarded number of options, shares or deferred units is determined (the "determination date") subject to the stated vesting period. The two-year awards generally vest in three equal installments beginning on the determination date and on January 1 of each of the two subsequent years. The three-year awards generally vest in one aggregate installment following the determination date. Once vested, options and SARs generally have a 10-year term during which they are exercisable.

As of December 31, 2011, total unrecognized compensation costs related to all unvested share-based awards totaled $91 million, which is expected to be recognized over a weighted-average period of 1.8 years. We recognized additional share-based compensation expense of $3 million, $12 million and $8 million in connection with modifications of share-based awards for the years ended December 31, 2011, 2010 and 2009, respectively.

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

	Years ended December 31, 2011	2010	2009
Dividend yield	4%	4%	—
Expected price volatility	40%	39%	49%
Risk-free interest rate	1.97%	2.30%	1.80%
Expected life of options	4.9 years	4.7 years	4.8 years
Weighted-average fair value of options granted	$ 19.75	$ 30.03	$ 26.07

Time-Based Awards

Stock options—The following table summarizes vested and unvested time-based vesting stock option ("time-based options") activity under our incentive plans during the year ended December 31, 2011:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2011	1,653,683	$ 66.37	5.29	$ 5
Granted	194,342	78.76		
Exercised	(210,997)	46.37		
Forfeited	(47,515)	84.77		
Expired	(10,229)	42.79		
Outstanding at December 31, 2011	1,579,284	$ 70.16	2.67	$ —
Vested and exercisable at December 31, 2011	1,182,287	$ 68.13	2.67	$ —

The weighted-average grant-date fair value of time-based options granted during the year ended December 31, 2011 was $19.75 per share. The total pretax intrinsic value of time-based options exercised during the year ended December 31, 2011 was $5 million. At December 31, 2011, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on these dates. There were 396,997 unvested time-based options outstanding as of December 31, 2011.

There were time-based options to purchase 253,288 and 597,898 shares granted during the years ended December 31, 2010 and 2009, respectively. The weighted-average grant-date fair value of time-based options granted was $30.03 and $26.07 per share for the years ended December 31, 2010 and 2009, respectively. There were 289,445 and 980,105 time-based options exercised during the years ended December 31, 2010 and 2009, respectively. The total pretax intrinsic value of time-based options exercised was $11 million and $43 million during the years ended December 31, 2010 and 2009, respectively. There were 470,400 and 656,790 unvested time-based options outstanding as of December 31, 2010 and 2009, respectively.

Restricted shares—The following table summarizes unvested share activity for time-based vesting restricted shares ("time-based shares") granted under our incentive plans during the year ended December 31, 2011:

	Number of shares	Weighted-average grant-date fair value per share
Unvested at January 1, 2011	3,939	$ 132.32
Vested	(3,939)	132.32
Unvested at December 31, 2011	—	$ —

We did not grant time-based shares during the years ended December 31, 2011, 2010 and 2009. There were 92,573 and 320,782 time-based shares that vested during the years ended December 31, 2010 and 2009, respectively. The total grant-date fair value of time-based shares that vested was $1 million, $10 million and $39 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Deferred units—A deferred unit is a unit that is equal to one share but has no voting rights until the underlying shares are issued. The following table summarizes unvested activity for time-based vesting deferred units ("time-based units") granted under our incentive plans during the year ended December 31, 2011:

	Number of units	Weighted-average grant-date fair value per share
Unvested at January 1, 2011	1,844,784	$ 75.23
Granted	1,090,747	77.55
Vested	(832,252)	78.97
Forfeited	(163,439)	76.94
Unvested at December 31, 2011	1,939,840	$ 74.78

The total grant-date fair value of the time-based units vested during the year ended December 31, 2011 was $66 million.

There were 1,055,367 and 1,287,893 time-based units granted during the years ended December 31, 2010 and 2009, respectively. The weighted-average grant-date fair value of time-based units granted was $76.83 and $60.53 per share for the years ended December 31, 2010 and 2009, respectively. There were 559,339 and 282,543 time-based units that vested during the years ended December 31, 2010 and 2009, respectively. The total grant-date fair value of deferred units that vested was $45 million and $33 million for the years ended December 31, 2010 and 2009, respectively.

SARs—The following table summarizes share-settled SARs activity under our incentive plans during the year ended December 31, 2011:

	Number of awards	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2011	189,139	$ 93.28	5.76	$ —
Exercised	(1,400)	77.73	—	—
Forfeited	(7,768)	105.57	—	—
Outstanding at December 31, 2011	179,971	$ 92.87	4.66	$ —
Vested and exercisable at December 31, 2011	179,971	$ 92.87	4.66	$ —

At January 1 and December 31, 2011, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on those dates. We did not grant share-settled SARs during the years ended December 31, 2011, 2010, and 2009. There were no share-settled SARs exercised during the year ended December 31, 2010. There were 224 share-settled SARs exercised with a total pretax intrinsic value of zero during the year ended December 31, 2009. There were no unvested share-settled SARs outstanding as of December 31, 2011, 2010 and 2009.

Performance-Based Awards

Stock options—We grant performance-based stock options ("performance-based options") that can be earned depending on the achievement of certain performance targets. The number of options earned is quantified upon completion of the performance period at the determination date. The following table summarizes vested and unvested performance-based option activity under our incentive plans during the year ended December 31, 2011:

	Number of shares under option	Weighted-average exercise price per share	Weighted-average remaining contractual term (years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2011	179,262	$ 75.30	5.22	$ —
Outstanding at December 31, 2011	179,262	$ 75.30	4.23	$ —
Vested and exercisable at December 31, 2011	179,262	$ 75.30	4.23	$ —

At December 31, 2011, we have presented the aggregate intrinsic value as zero since the weighted-average exercise price per share exceeded the market price of our shares on that date. We did not grant performance-based options during the years ended December 31, 2011, 2010 and 2009. There were no performance-based options exercised during the years ended December 31, 2011, 2010 and 2009. There were no unvested performance-based stock options outstanding as of December 31, 2011, 2010 and 2009.

Market-Based Awards

Deferred units—We grant market-based deferred units ("market-based units") that can be earned depending on the achievement of certain market conditions. The number of units earned is quantified upon completion of the specified period at the determination date. The following table summarizes unvested activity for market-based units granted under our incentive plans during the year ended December 31, 2011:

	Number of units	Weighted-average grant-date fair value per share
Unvested at January 1, 2011	422,906	$ 89.14
Granted	98,797	78.69
Forfeited	(105,756)	121.89
Unvested at December 31, 2011	415,947	$ 75.98

There were 122,934 and 285,012 market-based units granted with a weighted-average grant-date fair value of $82.55 and $75.98 per share during the years ended December 31, 2010 and 2009, respectively. No market-based units vested in the years ended December 31, 2011, 2010 and 2009.

Note 19—Supplemental Balance Sheet Information

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

	December 31, 2011	December 31, 2010
Other current liabilities		
Accrued payroll and employee benefits	$ 340	$ 270
Distribution payable	278	—
Deferred revenue	181	134
Deferred revenue of consolidated variable interest entities	16	16
Accrued taxes, other than income	127	126
Accrued interest	132	97
Unearned income	2	15
Contingent liabilities	1,229	164
Other	45	61
Total other current liabilities	$ 2,350	$ 883

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

	December 31, 2011	December 31, 2010
Other long-term liabilities		
Long-term income taxes payable	$ 729	$ 675
Accrued pension liabilities	579	426
Deferred revenue	244	302
Deferred revenue of consolidated variable interest entities	85	91
Drilling contract intangibles	103	152
Accrued retiree life insurance and medical benefits	49	52
Other	114	93
Total other long-term liabilities	$ 1,903	$ 1,791

Note 20—Supplemental Cash Flow Information

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

	Years ended December 31, 2011	2010	2009
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable	$ (174)	$ 386	$ 504
Increase in other current assets	(73)	(75)	(50)
Increase in other assets	(5)	(40)	(30)
Increase (decrease) in accounts payable and other current liabilities	978	227	(60)
Decrease in other long-term liabilities	(34)	(52)	(7)
Change in income taxes receivable / payable, net	53	(37)	77
	$ 745	$ 409	$ 434

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

	Years ended December 31, 2011	2010	2009
Certain cash operating activities			
Cash payments for interest	$ 626	$ 641	$ 683
Cash payments for income taxes	338	493	663
Non-cash investing and financing activities			
Capital expenditures, accrued at end of period (a)	$ 68	$ 69	$ 139
Asset capitalized under capital leases (b)	—	—	716
Non-cash proceeds received for the sale of assets (c)	—	134	—

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

(b) On August 4, 2009, we accepted delivery of *Petrobras 10000* and recorded non-cash additions of $716 million to property and equipment, net along with a corresponding increase to long-term debt. See Note 12—Debt and Note 15—Commitments and Contingencies.

(c) 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 face value amount of $165 million. We recognized the notes receivable at their estimated fair value, in the aggregate amount of $134 million, measured at the time of the sale. See Note 23—Variable Interest Entities and Note 10—Drilling Fleet.

Note 21—Fair Value of Financial Instruments

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

	December 31, 2011		December 31, 2010	
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and cash equivalents	$ 4,017	$ 4,017	$ 3,394	$ 3,394
Accounts receivable	2,049	2,049	1,653	1,653
Notes receivable and working capital loan receivable	139	139	115	115
Restricted cash investments	928	975	47	47
Long-term debt, including current maturities	12,698	13,074	10,271	10,562
Long-term debt of consolidated variable interest entities, including current maturities	838	838	950	964
Derivative instruments, assets	36	36	21	21
Derivative instruments, liabilities	38	38	13	13

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

Cash and cash equivalents—The carrying amount of cash and cash equivalents, which are stated at cost plus accrued interest, approximates fair value because of the short maturities of those instruments.

Accounts receivable—The carrying amount, net of valuation allowance, approximates fair value because of the short maturities of those instruments.

Notes receivable and working capital loan receivable—The carrying amount represents the amortized cost of our investment, which approximates the estimated fair value. We measured the estimated fair value using significant unobservable inputs, including the credit rating of the borrower. At December 31, 2011, the aggregate carrying amount of our notes receivable and working capital loan receivable was $139 million, including $37 million and $102 million recorded in other current assets and other assets, respectively. At December 31, 2010, the aggregate carrying amount of our notes receivable and working capital loan receivable was $115 million, including $4 million and $111 million recorded in other current assets and other assets, respectively.

Restricted cash investments—For the Aker Restricted Cash Investment, acquired in our acquisition of Aker Drilling, the carrying amount of $889 million at December 31, 2011 represents the amortized cost of our investment. The fair value of our Aker Restricted Cash Investments was measured using significant other observable inputs. In the case of the restricted cash investments for the TPDI Credit Facilities and the ADDCL Credit Facilities, the carrying amount approximates fair value due to the short term nature of the instruments in which the restricted cash investments are held. The aggregate carrying amount of the restricted cash investments for the TPDI Credit Facilities and the ADDCL Credit Facilities was $39 million at December 31, 2011 and 2010.

Debt—The fair value of our fixed-rate debt is measured using significant other observable inputs. The carrying amounts of our variable-rate debt approximates fair value because the terms of those debt instruments include short-term interest rates and exclude penalties for prepayment.

Derivative instruments—The carrying amount of our derivative instruments represents the estimated fair value, measured using significant other observable inputs.

Note 22—Financial Instruments and Risk Concentration

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

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

In connection with our acquisition of Aker Drilling, we assumed certain interest rate swaps that are not designated as hedging instruments for accounting purposes. We record these undesignated interest rate swaps at fair value and record changes to the fair value in current period earnings as an adjustment to interest expense.

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

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

We do not enter into currency exchange derivative transactions for speculative purposes. We record designated currency exchange derivative instruments at fair value and defer gains and losses in other comprehensive income, recognizing the gains and losses when the underlying currency exchange exposure is realized. We record undesignated currency exchange derivative instruments at fair value and record changes to the fair value in current period earnings as an adjustment to currency exchange gains or losses. At December 31, 2011, we had cross-currency swaps, assumed in connection with our acquisition of Aker Drilling, that were designated as cash flow hedges of certain debt instruments denominated in Norwegian kroner. At December 31, 2010, we had no outstanding currency exchange derivative instruments.

Credit risk—Financial instruments that potentially subject us to concentrations of credit risk are primarily cash and cash equivalents, short-term investments and trade receivables. It is our practice to place our cash and cash equivalents in time deposits at commercial banks with high credit ratings or mutual funds, which invest exclusively in high quality money market instruments. We limit the amount of exposure to any one institution and do not believe we are exposed to any significant credit risk.

We derive the majority of our revenue from services to international oil companies, government-owned and government-controlled oil companies. Receivables are dispersed in various countries (see Note 25—Operating Segments, Geographic Analysis and Major Customers). We maintain an allowance for doubtful accounts receivable based upon expected collectability and establish reserves for doubtful accounts on a case-by-case basis when we believe the required payment of specific amounts owed to us is unlikely to occur. Although we have encountered isolated credit concerns related to independent oil companies, we are not aware of any significant credit risks related to our customer base and do not generally require collateral or other security to support customer receivables.

Labor agreements—We require highly skilled personnel to operate our drilling units. We conduct extensive personnel recruiting, training and safety programs. At December 31, 2011, we had approximately 18,700 employees, including approximately 1,850 persons engaged through contract labor providers. Some of our employees working in Angola, the U.K., Norway and Australia, are represented by, and some of our contracted labor work under, collective bargaining agreements. Many of these represented individuals are working under agreements that are subject to annual salary negotiation. These negotiations could result in higher personnel expenses, other increased costs or increased operational restrictions as the outcome of such negotiations apply to all offshore employees not just the union members.

Note 23—Variable Interest Entities

Consolidated variable interest entities—TPDI and ADDCL, joint venture companies in which we hold interests, were formed to own and operate certain ultra-deepwater drillships. We have determined that each of these joint venture companies meets the criteria of a variable interest entity for accounting purposes because its equity at risk is insufficient to permit it to carry on its activities without additional subordinated financial support from us. We have also determined, in each case, that we are the primary beneficiary for accounting purposes since (a) we have 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 have 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 consolidate TPDI and ADDCL in our consolidated financial statements, we eliminate intercompany transactions, and we present the interests that are not owned by us as noncontrolling interest on our consolidated balance sheets. The carrying amounts associated with these joint venture companies, after eliminating the effect of intercompany transactions, were as follows (in millions):

	December 31, 2011			December 31, 2010		
	Assets	Liabilities	Net carrying amount	Assets	Liabilities	Net carrying amount
Variable interest entity						
TPDI	$ 1,562	$ 673	$ 889	$ 1,598	$ 763	$ 835
ADDCL	930	334	596	864	345	519
Total	$ 2,492	$ 1,007	$ 1,485	$ 2,462	$ 1,108	$ 1,354

At December 31, 2011 and 2010, 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 $2,165 million and $2,191 million, respectively. See Note 12—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 (see Note 10—Drilling Fleet). The notes receivable, originally issued in exchange for and secured by two drilling units, have stated interest rates of nine percent and are payable in scheduled quarterly installments of principal and interest through maturity in January 2015. Additionally, we provide Awilco with a working capital loan, also secured by the drilling units, that has a stated interest rate of 10 percent and a maximum borrowing amount of $35 million. We evaluate the credit quality and financial condition of Awilco quarterly. The aggregate carrying amount of the notes receivable was $110 million and $109 million at December 31, 2011 and 2010, respectively. The aggregate carrying amount of the working capital loan receivable was $29 million and $6 million at December 31, 2011 and 2010, respectively.

During the year ended December 31, 2011, we determined that Awilco no longer met the definition of a variable interest entity following a private placement of its shares and the listing of its shares on the Oslo Stock Exchange and the successful marketing of its two drilling units.

Note 24—Related Party Transactions

Quantum Pacific Management Limited—We hold a 50 percent interest in TPDI, a consolidated British Virgin Islands joint venture company formed to own and operate *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. Quantum holds the remaining 50 percent interest. Quantum has the unilateral right to exchange its interest in the joint venture for our shares or cash, at an amount based on an appraisal of the fair value of the drillships, subject to certain adjustments.

As of December 31, 2011 and 2010, TPDI had outstanding promissory notes in the aggregate amount of $296 million, of which $148 million was due to Quantum and was included in long-term debt of consolidated variable interest entities on our consolidated balance sheets.

Angco Cayman Limited—We hold a 65 percent interest in ADDCL, a consolidated Cayman Islands joint venture company formed to own and operate *Discoverer Luanda*. Angco Cayman holds the remaining 35 percent interest in ADDCL. Beginning January 31, 2016, Angco Cayman will have the right to exchange its interest in the joint venture for cash at an amount based on the appraisal of the fair value of the drillship, subject to certain adjustments.

Overseas Drilling Limited—We held a 50 percent interest in ODL, an unconsolidated Cayman Islands joint venture company, which owns *Joides Resolution*, a coring drillship that was adapted for scientific research. Under a management services agreement with ODL, we provided certain operational and management services through the date of the sale of our interest. We earned $1 million and $2 million for these services in each of the years ended December 31, 2011 and 2010, respectively.

During the year ended December 31, 2011, we completed the sale of our 50 percent ownership interest in ODL to Siem Offshore Inc. In connection with the sale, we received net proceeds of $22 million and recognized a net gain of $13 million ($0.04 per diluted share from continuing operations), recorded in other, net, which had no tax effect.

Note 25—Operating Segments, Geographic Analysis and Major Customers

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

Geographic analysis—Operating revenues by country were as follows (in millions):

	Years ended December 31,		
	2011	2010	2009
Operating revenues			
U.S.	$ 1,975	$ 2,087	$ 2,209
U.K.	1,211	1,183	1,563
Brazil	1,019	1,288	1,108
Other countries (a)	4,937	4,908	6,561
Total operating revenues	$ 9,142	$ 9,466	$ 11,441

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

Long-lived assets by country were as follows (in millions):

	December 31,	
	2011	2010
Long-lived assets		
U.S.	$ 6,549	$ 5,519
Brazil	2,185	2,472
India	1,593	2,632
Other countries (a)	12,202	10,696
Total long-lived assets	$ 22,529	$ 21,319

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

A substantial portion of our assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the revenues generated by such assets during the periods. Although we are organized under the laws of Switzerland, we do not conduct any operations and do not have operating revenues in Switzerland. At December 31, 2011 and 2010, we had $8 million and $15 million, respectively, of long-lived assets in Switzerland.

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

Major customers—For the years ended December 31, 2011, 2010 and 2009, BP accounted for approximately 10 percent, 10 percent and 12 percent, respectively, of our operating revenues.

Note 26—Condensed Consolidating Financial Information

Transocean Inc., a wholly owned subsidiary of Transocean Ltd., is the issuer of certain notes and debentures, which have been guaranteed by Transocean Ltd. Transocean Ltd. has also guaranteed borrowings under the commercial paper program and the Five-Year Revolving Credit Facility. Transocean Ltd.'s guarantee of debt securities of Transocean Inc. is full and unconditional. Transocean Ltd. is not subject to any significant restrictions on its ability to obtain funds from its consolidated subsidiaries or entities accounted for under the equity method by dividends, loans or return of capital distributions.

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

	Year ended December 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 9,160	$ (18)	$ 9,142
Cost and expenses	44	4	8,663	(18)	8,693
Loss on impairment	—	—	(5,229)	—	(5,229)
Gain on disposal of assets, net	—	—	4	—	4
Operating loss	(44)	(4)	(4,728)	—	(4,776)
Other income (expense), net					
Interest expense, net	(11)	(510)	(56)	—	(577)
Equity in earnings	(5,670)	(5,145)	18	10,815	18
Other, net	—	9	(108)	—	(99)
	(5,681)	(5,646)	(146)	10,815	(658)
Loss from continuing operations before income tax expense	(5,725)	(5,650)	(4,874)	10,815	(5,434)
Income tax expense	—	—	395	—	395
Loss from continuing operations	(5,725)	(5,650)	(5,269)	10,815	(5,829)
Income from discontinued operations, net of tax	—	—	197	—	197
Net loss	(5,725)	(5,650)	(5,072)	10,815	(5,632)
Net income attributable to noncontrolling interest	—	—	93	—	93
Net loss attributable to controlling interest	$ (5,725)	$ (5,650)	$ (5,165)	$ 10,815	$ (5,725)

	Year ended December 31, 2010				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 9,481	$ (15)	$ 9,466
Cost and expenses	45	3	6,823	(15)	6,856
Loss on impairment	—	—	(1,010)	—	(1,010)
Gain on disposal of assets, net	—	—	257	—	257
Operating income (loss)	(45)	(3)	1,905	—	1,857
Other income (expense), net					
Interest income (expense), net	1	(494)	(51)	—	(544)
Equity in earnings	1,005	1,519	8	(2,524)	8
Other, net	—	(7)	(24)	—	(31)
	1,006	1,018	(67)	(2,524)	(567)
Income from continuing operations before income tax expense	961	1,015	1,838	(2,524)	1,290
Income tax expense	—	—	336	—	336
Income from continuing operations	961	1,015	1,502	(2,524)	954
Income from discontinued operations, net of tax	—	—	34	—	34
Net income	961	1,015	1,536	(2,524)	988
Net income attributable to noncontrolling interest	—	—	27	—	27
Net income attributable to controlling interest	$ 961	$ 1,015	$ 1,509	$ (2,524)	$ 961

	Year ended December 31, 2009				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Operating revenues	$ —	$ —	$ 11,455	$ (14)	$ 11,441
Cost and expenses	26	4	6,692	(14)	6,708
Loss on impairment	—	—	(334)	—	(334)
Loss on disposal of assets, net	—	—	(9)	—	(9)
Operating income (loss)	(26)	(4)	4,420	—	4,390
Other income (expense), net					
Interest income (expense), net	1	(521)	41	—	(479)
Equity in earnings	3,206	3,773	6	(6,979)	6
Other, net	—	(43)	45	—	2
	3,207	3,209	92	(6,979)	(471)
Income from continuing operations before income tax expense	3,181	3,205	4,512	(6,979)	3,919
Income tax expense	—	—	723	—	723
Income from continuing operations	3,181	3,205	3,789	(6,979)	3,196
Loss from discontinued operations, net of tax	—	—	(26)	—	(26)
Net income	3,181	3,205	3,763	(6,979)	3,170
Net loss attributable to noncontrolling interest	—	—	(11)	—	(11)
Net income attributable to controlling interest	$ 3,181	$ 3,205	$ 3,774	$ (6,979)	$ 3,181

	December 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 3	$ 2,793	$ 1,221	$ —	$ 4,017
Other current assets	8	784	4,493	(1,693)	3,592
Total current assets	11	3,577	5,714	(1,693)	7,609
Property and equipment, net	1	—	22,528	—	22,529
Goodwill	—	—	3,205	—	3,205
Investment in affiliates	16,503	27,582	—	(44,085)	—
Other assets	—	1,368	17,908	(17,531)	1,745
Total assets	16,515	32,527	49,355	(63,309)	35,088
Liabilities and equity					
Debt due within one year	—	1,693	346	—	2,039
Other current liabilities	294	367	4,351	(1,693)	3,319
Total current liabilities	294	2,060	4,697	(1,693)	5,358
Long-term debt	495	14,308	14,225	(17,531)	11,497
Other long-term liabilities	25	439	1,962	—	2,426
Total long-term liabilities	520	14,747	16,187	(17,531)	13,923
Commitments and contingencies					
Redeemable noncontrolling interest	—	—	116	—	116
Total equity	15,701	15,720	28,355	(44,085)	15,691
Total liabilities and equity	$ 16,515	$ 32,527	$ 49,355	$ (63,309)	$ 35,088

	December 31, 2010				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 38	$ 2,041	$ 1,315	$ —	$ 3,394
Other current assets	12	788	3,189	(1,188)	2,801
Total current assets	50	2,829	4,504	(1,188)	6,195
Property and equipment, net	1	—	21,318	—	21,319
Goodwill	—	—	8,132	—	8,132
Investment in affiliates	21,373	33,473	19	(54,846)	19
Other assets	—	1,017	14,001	(13,872)	1,146
Total assets	21,424	37,319	47,974	(69,906)	36,811
Liabilities and equity					
Debt due within one year	—	1,891	121	—	2,012
Other current liabilities	21	444	2,547	(1,188)	1,824
Total current liabilities	21	2,335	2,668	(1,188)	3,836
Long-term debt	—	13,354	9,727	(13,872)	9,209
Other long-term liabilities	20	292	2,054	—	2,366
Total long-term liabilities	20	13,646	11,781	(13,872)	11,575
Commitments and contingencies					
Redeemable noncontrolling interest	—	—	25	—	25
Total equity	21,383	21,338	33,500	(54,846)	21,375
Total liabilities and equity	$ 21,424	$ 37,319	$ 47,974	$ (69,906)	$ 36,811

	Year ended December 31, 2011				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (52)	$ 503	$ 1,334	$ —	$ 1,785
Cash flows from investing activities					
Capital expenditures	—	—	(1,020)	—	(1,020)
Investment in business combination, net of cash acquired	—	—	(1,246)	—	(1,246)
Proceeds from disposal of assets, net	—	—	177	—	177
Proceeds from disposal of discontinued operations, net	—	—	284	—	284
Investing activities with affiliates, net	(875)	(325)	(693)	1,893	—
Other, net	—	(23)	(68)	—	(91)
Net cash provided by (used in) investing activities	(875)	(348)	(2,566)	1,893	(1,896)
Cash flows from financing activities					
Changes in short-term borrowings, net	—	(88)	—	—	(88)
Proceeds from debt	435	2,504	—	—	2,939
Repayments of debt	(429)	(1,827)	(153)	—	(2,409)
Proceeds from share issuance, net	1,211	—	—	—	1,211
Distribution of qualifying additional paid-in capital	(763)	—	—	—	(763)
Financing activities with affiliates, net	495	43	1,355	(1,893)	—
Other, net	(57)	(35)	(64)	—	(156)
Net cash provided by (used in) financing activities	892	597	1,138	(1,893)	734
Net increase (decrease) in cash and cash equivalents	(35)	752	(94)	—	623
Cash and cash equivalents at beginning of period	38	2,041	1,315	—	3,394
Cash and cash equivalents at end of period	$ 3	$ 2,793	$ 1,221	$ —	$ 4,017

	Year ended December 31, 2010				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (33)	$ (358)	$ 4,337	$ —	$ 3,946
Cash flows from investing activities					
Capital expenditures	(4)	—	(1,387)	—	(1,391)
Proceeds from insurance recoveries for loss of drilling unit	—	—	560	—	560
Proceeds from disposal of assets, net	—	—	60	—	60
Investing activities with affiliates, net	310	1,357	(1,694)	27	—
Other, net	—	(6)	56	—	50
Net cash provided by (used in) investing activities	306	1,351	(2,405)	27	(721)
Cash flows from financing activities					
Changes in short-term borrowings, net	—	(193)	—	—	(193)
Proceeds from debt	—	1,999	55	—	2,054
Repayments of debt	—	(2,245)	(320)	—	(2,565)
Purchases of shares held in treasury	(240)	—	—	—	(240)
Financing activities with affiliates, net	—	1,384	(1,357)	(27)	—
Other, net	—	(14)	(3)	—	(17)
Net cash provided by (used in) financing activities	(240)	931	(1,625)	(27)	(961)
Net increase in cash and cash equivalents	33	1,924	307	—	2,264
Cash and cash equivalents at beginning of period	5	117	1,008	—	1,130
Cash and cash equivalents at end of period	$ 38	$ 2,041	$ 1,315	$ —	$ 3,394

	Year ended December 31, 2009				
	Parent Guarantor	Subsidiary Issuer	Other Subsidiaries	Consolidating adjustments	Consolidated
Cash flows from operating activities	$ (24)	$ (429)	$ 6,051	$ —	$ 5,598
Cash flows from investing activities					
Capital expenditures	(1)	—	(3,040)	—	(3,041)
Investing activities with affiliates, net	29	1,667	(2,068)	372	—
Other, net	—	—	347	—	347
Net cash provided by (used in) investing activities	28	1,667	(4,761)	372	(2,694)
Cash flows from financing activities					
Changes in short-term borrowings, net	—	(382)	—	—	(382)
Proceeds from debt	—	—	514	—	514
Repayments of debt	—	(2,865)	(6)	—	(2,871)
Financing activities with affiliates, net	—	2,008	(1,636)	(372)	—
Other, net	1	4	(3)	—	2
Net cash provided by (used in) financing activities	1	(1,235)	(1,131)	(372)	(2,737)
Net increase in cash and cash equivalents	5	3	159	—	167
Cash and cash equivalents at beginning of period	—	114	849	—	963
Cash and cash equivalents at end of period	$ 5	$ 117	$ 1,008	$ —	$ 1,130

Note 27—Quarterly Results (Unaudited)

Shown below are selected unaudited quarterly data. Amounts are rounded for consistency in presentation with no effect to the results of operations previously reported on Form 10-Q or Form 10-K.

	Three months ended			
	March 31,	June 30,	September 30,	December 31,
	(In millions, except per share data)			
2011				
Operating revenues	$ 2,144	$ 2,334	$ 2,242	$ 2,422
Operating income (loss) (a)	372	391	268	(5,807)
Income (loss) from continuing operations	164	162	(53)	(6,102)
Net income (loss) attributable to controlling interest (a) (b)	310	155	(71)	(6,119)
Per share earnings (loss) from continuing operations				
Basic	$ 0.42	$ 0.47	$ (0.20)	$ (18.70)
Diluted	$ 0.42	$ 0.47	$ (0.20)	$ (18.70)
Weighted-average shares outstanding				
Basic	319	320	320	329
Diluted	320	320	320	329
2010				
Operating revenues	$ 2,579	$ 2,479	$ 2,281	$ 2,127
Operating income (loss) (c)	942	949	634	(668)
Income (loss) from continuing operations	683	712	363	(804)
Net income (loss) attributable to controlling interest (c)	677	715	368	(799)
Per share earnings (loss) from continuing operations				
Basic	$ 2.09	$ 2.20	$ 1.10	$ (2.53)
Diluted	$ 2.08	$ 2.20	$ 1.10	$ (2.53)
Weighted-average shares outstanding				
Basic	321	319	319	319
Diluted	322	320	319	319

(a) Third quarter included a loss of $78 million on forward exchange contract. Fourth quarter included an estimated loss of $5.2 billion on impairment of goodwill and an estimated loss of $1.0 billion in connection with loss contingencies associated with the Macondo well incident. See Note 5—Impairments, Note 10—Drilling Fleet and Note 15—Commitments and Contingencies.

(b) First, third and fourth quarters included gains (losses) on disposal of discontinued operations in the amount of $173 million, $(4) million and $12 million, respectively.

(c) Second quarter included gain of $267 million on the loss of *Deepwater Horizon*. Fourth quarter included loss of $1.0 billion on impairment of long-lived assets. See Note 5—Impairments and Note 10—Drilling Fleet.

Note 28—Subsequent Events

Debt—Subsequent to December 31, 2011, we redeemed the remaining $30 million aggregate principal amount of the Series B Convertible Senior Notes.

Drilling fleet—Subsequent to December 31, 2011, we entered into agreements to sell the Standard Jackups, *GSF Rig 136*, *Transocean Nordic* and *Transocean Shelf Explorer*, and we reclassified to assets held for sale the rigs and related equipment, having an aggregate carrying amount of $59 million.

Discontinued operations—Subsequent to December 31, 2011, we entered into an agreement to sell the assets of Challenger Minerals Inc.

U.S. tax investigations—Subsequent to December 31, 2011, 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. These items would result in net adjustments of approximately $473 million of additional taxes, excluding interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Furthermore, if the authorities were to continue to pursue these positions with respect to subsequent years and were successful in such assertions, our effective tax rate on worldwide earnings with respect to years following 2009 could increase substantially, and could have a material adverse effect on our consolidated results of operations and cash flows. We believe our returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims.

Norway tax investigations—In January 2012, the Norwegian authorities supplemented the previously issued criminal indictments by issuing a financial claim of approximately $315 million, jointly and severally, against our two subsidiaries, the two external advisors and the external tax attorney. This compensation claim directly overlaps with an existing civil tax assessment and does not represent any incremental financial exposure to us. In February 2012, the authorities dropped the previously existing tax assessment.

Macondo well incident—On January 26, 2012, the MDL Court ruled that BP is required 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 Clean Water Act. 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. Our motion for partial summary judgment and the court's ruling did not address the issue of contractual indemnity for criminal fines and penalties. The law generally disallows contractual indemnity for criminal fines and penalties as against public policy.

On February 22, 2012, the MDL Court ruled that we are not liable as a responsible party for damages under OPA with respect to the below surface discharges from the Macondo well. The 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 Clean Water Act, and that we therefore are not liable for such discharges as an owner of the vessel under the Clean Water Act. However, the court ruled that the issue of whether we could be held liable for such discharge under the Clean Water Act 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.

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

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

Item 9A. Controls and Procedures

Disclosure controls and procedures—We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures, as defined in Exchange Act Rules 13a-15(e) and 15d-15(e), were effective as of December 31, 2011 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Internal controls over financial reporting—There were no changes in these internal controls during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 11. Executive Compensation

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

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

Item 14. Principal Accountant Fees and Services

The information required by Items 10, 11, 12, 13 and 14 is incorporated herein by reference to our definitive proxy statement for our 2012 annual general meeting of shareholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of December 31, 2011. Certain information with respect to our executive officers is set forth in Item 4 of this annual report under the caption "Executive Officers of the Registrant."

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Financial Statements

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

(2) Financial Statement Schedules

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

	Balance at beginning of period	Additions: Charge to cost and expenses	Additions: Charge to other accounts -describe	Deductions -describe	Balance at end of period
<u>Year ended December 31, 2009</u>					
Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 114	$ 27	$ —	$ 76 (a)	$ 65
Allowance for obsolete materials and supplies	49	17	—	—	66
Valuation allowance on deferred tax assets	111	49	—	—	160
<u>Year ended December 31, 2010</u>					
Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 65	$ 5	$ —	$ 32 (a)	$ 38
Allowance for obsolete materials and supplies	66	6	—	2 (b)	70
Valuation allowance on deferred tax assets	160	8	—	4 (c)	164
<u>Year ended December 31, 2011</u>					
Reserves and allowances deducted from asset accounts:					
Allowance for doubtful accounts receivable	$ 38	$ —	$ —	$ 10 (a)	$ 28
Allowance for obsolete materials and supplies	70	5	—	2 (d)	73
Valuation allowance on deferred tax assets	164	19	—	—	183

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

(b) Amount represents $1 million related to sale of rigs and inventory and $1 million related to the loss of *Deepwater Horizon*.

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

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

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

(3) Exhibits

The following exhibits are filed in connection with this Report:

Number	Description
3.1	Articles of Association of Transocean Ltd. (incorporated by reference to Exhibit 3.2 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on December 5, 2011)
3.2	Organizational Regulations of Transocean Ltd. (incorporated by reference to Exhibit 3.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on February 23, 2012)
4.1	Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.2	First Supplemental Indenture dated as of April 15, 1997 between Transocean Offshore Inc. and Texas Commerce Bank National Association, as trustee, supplementing the Indenture dated as of April 15, 1997 (incorporated by reference to Exhibit 4.2 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.3	Second Supplemental Indenture dated as of May 14, 1999 between Transocean Offshore (Texas) Inc., Transocean Offshore Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Transocean Offshore Inc.'s Post-Effective Amendment No. 1 to Registration Statement on Form S-3 (Registration No. 333-59001-99))
4.4	Third Supplemental Indenture dated as of May 24, 2000 between Transocean Sedco Forex Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Transocean Sedco Forex Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on May 24, 2000)
4.5	Fourth Supplemental Indenture dated as of May 11, 2001 between Transocean Sedco Forex Inc. and The Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Quarterly Report on Form 10-Q (Commission File No. 333-75899) for the quarter ended March 31, 2001)
4.6	Fifth Supplemental Indenture, dated as of December 18, 2008, among Transocean Ltd., Transocean Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.4 to Transocean Ltd.'s Current Report on Form 8-K filed on December 19, 2008)
4.7	Form of 7.45% Notes due April 15, 2027 (incorporated by reference to Exhibit 4.3 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.8	Form of 8.00% Debentures due April 15, 2027 (incorporated by reference to Exhibit 4.4 to Transocean Offshore Inc.'s Current Report on Form 8-K (Commission File No. 001-07746) filed on April 30, 1997)
4.9	Form of 6.625% Note due April 15, 2011 (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on April 9, 2001)
4.10	Form of 7.5% Note due April 15, 2031 (incorporated by reference to Exhibit 4.3 to Transocean Sedco Forex Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on April 9, 2001)
4.11	Officers' Certificate establishing the terms of the 6.50% Notes due 2003, 6.75% Notes due 2005, 6.95% Notes due 2008, 7.375% Notes due 2018, 9.125% Notes due 2003 and 9.50% Notes due 2008 (incorporated by reference to Exhibit 4.13 to Transocean Sedco Forex Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the fiscal year ended December 31, 2001)
4.12	Officers' Certificate establishing the terms of the 7.375% Notes due 2018 (incorporated by reference to Exhibit 4.14 to Transocean Sedco Forex Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the fiscal year ended December 31, 2001)
4.13	Indenture dated as of February 1, 2003, between GlobalSantaFe Corporation and Wilmington Trust Company, as trustee, relating to debt securities of GlobalSantaFe Corporation (incorporated by reference to Exhibit 4.9 to GlobalSantaFe Corporation's Annual Report on Form 10-K (Commission File No. 001-14634) for the year ended December 31, 2002)
4.14	Supplemental Indenture dated November 27, 2007 among Transocean Worldwide Inc., GlobalSantaFe Corporation and Wilmington Trust Company, as trustee, to the Indenture dated as of February 1, 2003 between GlobalSantaFe Corporation and Wilmington Trust Company (incorporated by reference to Exhibit 4.4 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)
4.15	Form of 7% Note Due 2028 (incorporated by reference to Exhibit 4.2 of Global Marine Inc.'s Current Report on Form 8-K (Commission File No. 1-5471) filed on May 22, 1998)
4.16	Terms of 7% Note Due 2028 (incorporated by reference to Exhibit 4.1 of Global Marine Inc.'s Current Report on Form 8-K (Commission File No. 1-5471) filed on May 22, 1998)

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

4.18 Form of 5% Note due 2013 (incorporated by reference to Exhibit 4.10 to GlobalSantaFe Corporation's Annual Report on Form 10-K (Commission File No. 001-14634) for the year ended December 31, 2002)

4.19 Terms of 5% Note due 2013 (incorporated by reference to Exhibit 4.11 to GlobalSantaFe Corporation's Annual Report on Form 10-K (Commission File No. 001-14634) for the year ended December 31, 2002)

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

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

4.22 Second Supplemental Indenture, dated as of December 11, 2007, between Transocean Inc. and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.38 to Transocean Inc.'s Annual Report on Form 10-K (Commission File No. 333-75899) for the year ended December 31, 2007)

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

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

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

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

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

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

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

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

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

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

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

*	10.7	1997 Long-Term Incentive Plan of Reading & Bates Corporation (incorporated by reference to Exhibit 99.A to Reading & Bates' Proxy Statement (Commission File No. 001-05587) dated March 28, 1997)
*	10.8	1998 Employee Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.A to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 23, 1998)
*	10.9	1998 Director Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.B to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 23, 1998)
*	10.10	1999 Employee Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.A to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 13, 1999)
*	10.11	1999 Director Long-Term Incentive Plan of R&B Falcon Corporation (incorporated by reference to Exhibit 99.B to R&B Falcon Corporation's Proxy Statement (Commission File No. 001-13729) dated April 13, 1999)
	10.12	Master Separation Agreement dated February 4, 2004 by and among Transocean Inc., Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on March 3, 2004)
	10.13	Tax Sharing Agreement dated February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 99.3 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on March 3, 2004)
	10.14	Amended and Restated Tax Sharing Agreement effective as of February 4, 2004 between Transocean Holdings Inc. and TODCO (incorporated by reference to Exhibit 4.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on November 30, 2006)
*	10.15	Form of 2004 Performance-Based Nonqualified Share Option Award Letter (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on February 15, 2005)
*	10.16	Form of 2004 Director Deferred Unit Award (incorporated by reference to Exhibit 10.5 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on February 15, 2005)
*	10.17	Form of 2008 Director Deferred Unit Award (incorporated by reference to Exhibit 10.20 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
*	10.18	Form of 2009 Director Deferred Unit Award (incorporated by reference to Exhibit 10.19 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2009)
*	10.19	Performance Award and Cash Bonus Plan of Transocean Ltd. (incorporated by reference to Exhibit 10.21 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
*	10.20	Executive Change of Control Severance Benefit (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on July 19, 2005)
*	10.21	Terms of July 2007 Employee Restricted Stock Awards (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2007)
*	10.22	Terms of July 2007 Employee Deferred Unit Awards (incorporated by reference to Exhibit 10.3 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2007)
*	10.23	Terms and Conditions of the July 2008 Employee Contingent Deferred Unit Award (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2008)
*	10.24	Terms and Conditions of the July 2008 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Form 10-Q (Commission File No. 333-75899) for the quarter ended June 30, 2008)
*	10.25	Terms and Conditions of the February 2009 Employee Deferred Unit Award (incorporated by reference to Exhibit 10.28 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
*	10.26	Terms and Conditions of the February 2009 Employee Contingent Deferred Unit Award (incorporated by reference to Exhibit 10.29 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
*	10.27	Terms and Conditions of the February 2009 Nonqualified Share Option Award (incorporated by reference to Exhibit 10.30 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
† *	10.28	Terms and Conditions of the February 2012 Long Term Incentive Plan Award
	10.29	Put Option and Registration Rights Agreement, dated as of October 18, 2007, among Pacific Drilling Limited, Transocean Pacific Drilling Inc., Transocean Inc. and Transocean Offshore International Ventures Limited (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on October 24, 2007)
	10.30	Form of Novation Agreement dated as of November 27, 2007 by and among GlobalSantaFe Corporation, Transocean Offshore Deepwater Drilling Inc. and certain executives (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)

* 10.31 Form of Severance Agreement with GlobalSantaFe Corporation Executive Officers (incorporated by reference to Exhibit 10.1 to GlobalSantaFe Corporation's Current Report on Form 8-K/A (Commission File No. 001-14634) filed on July 26, 2005)
* 10.32 Transocean Special Transition Severance Plan for Shore-Based Employees (incorporated by reference to Exhibit 10.3 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)
* 10.33 Global Marine Inc. 1990 Non-Employee Director Stock Option Plan (incorporated by reference to Exhibit 10.18 of Global Marine Inc.'s Annual Report on Form 10-K (Commission File No. 1-5471) for the year ended December 31, 1991); First Amendment (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended June 30, 1995); Second Amendment (incorporated by reference to Exhibit 10.37 of Global Marine Inc.'s Annual Report on Form 10-K (Commission File No. 1-5471) for the year ended December 31, 1996)
* 10.34 1997 Long-Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Registration Statement on Form S-8 (No. 333-7070) filed June 13, 1997); Amendment to 1997 Long Term Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20-F (Commission File No. 001-14634) for the calendar year ended December 31, 1998); Amendment to 1997 Long Term Incentive Plan dated December 1, 1999 (incorporated by reference to GlobalSantaFe Corporation's Annual Report on Form 20-F (Commission File No. 001-14634) for the calendar year ended December 31, 1999)
* 10.35 GlobalSantaFe Corporation 1998 Stock Option and Incentive Plan (incorporated by reference to Exhibit 10.1 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended March 31, 1998); First Amendment (incorporated by reference to Exhibit 10.2 of Global Marine Inc.'s Quarterly Report on Form 10-Q (Commission File No. 1-5471) for the quarter ended June 30, 2000)
* 10.36 GlobalSantaFe Corporation 2001 Non-Employee Director Stock Option and Incentive Plan (incorporated by reference to GlobalSantaFe Corporation's Registration Statement on Form S-8 (No. 333-73878) filed November 21, 2001)
* 10.37 GlobalSantaFe Corporation 2001 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to GlobalSantaFe Corporation's Quarterly Report on Form 10-Q (Commission File No. 001-14634) for the quarter ended June 30, 2001)
* 10.38 GlobalSantaFe 2003 Long-Term Incentive Plan (as Amended and Restated Effective June 7, 2005) (incorporated by reference to Exhibit 10.4 to GlobalSantaFe Corporation's Quarterly Report on Form 10-Q (Commission File No. 001-14634) for the quarter ended June 30, 2005)
* 10.39 Transocean Ltd. Pension Equalization Plan, as amended and restated, effective January 1, 2009 (incorporated by reference to Exhibit 10.41 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)
* 10.40 Transocean U.S. Supplemental Retirement Benefit Plan, as amended and restated, effective as of November 27, 2007 (incorporated by reference to Exhibit 10.11 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 3, 2007)
* 10.41 GlobalSantaFe Corporation Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.1 to the GlobalSantaFe Corporation Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
* 10.42 Transocean U.S. Supplemental Savings Plan (incorporated by reference to Exhibit 10.44 to Transocean Ltd.'s Annual Report on Form 10-K (Commission File No. 000-53533) for the year ended December 31, 2008)

10.43 Commercial Paper Dealer Agreement between Transocean Inc. and Lehman Brothers Inc., dated as of December 20, 2007 (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 21, 2007)

10.44 Amended and Restated Commercial Paper Dealer Agreement between Transocean Inc. and Barclays Capital Inc., dated as of December 3, 2008 (including form of Accession Agreement) (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 9, 2008)

10.45 Commercial Paper Dealer Agreement between Transocean Inc. and Morgan Stanley & Co. Incorporated, dated as of December 20, 2007 (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 21, 2007)

10.46 Amended and Restated Commercial Paper Dealer Agreement between Transocean Inc. and Morgan Stanley & Co. Incorporated, dated as of December 3, 2008 (including form of Accession Agreement) (incorporated by reference to Exhibit 10.3 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 9, 2008)

10.47 Commercial Paper Dealer Agreement between Transocean Inc. and J.P. Morgan Securities Inc., dated as of December 20, 2007 (incorporated by reference to Exhibit 10.3 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 21, 2007)

	10.48	Amended and Restated Commercial Paper Dealer Agreement between Transocean Inc. and J.P. Morgan Securities Inc., dated as of December 3, 2008 (including form of Accession Agreement) (incorporated by reference to Exhibit 10.2 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 9, 2008)
	10.49	Amended and Restated Commercial Paper Dealer Agreement between Transocean Inc. and Goldman, Sachs & Co., dated as of December 3, 2008 (including form of Accession Agreement) (incorporated by reference to Exhibit 10.4 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on December 9, 2008)
	10.50	Guarantee, dated as of December 19, 2008, of Transocean Ltd. pursuant to the Issuing and Paying Agent Agreement, dated as of December 20, 2007 (incorporated by reference to Exhibit 10.5 to Transocean Ltd.'s Current Report on Form 8-K filed on December 19, 2008)
	10.51	Form of Indemnification Agreement entered into between Transocean Ltd. and each of its Directors and Executive Officers (incorporated by reference to Exhibit 10.1 to Transocean Inc.'s Current Report on Form 8-K (Commission File No. 333-75899) filed on October 10, 2008)
*	10.52	Form of Assignment Memorandum for Executive Officers (incorporated by reference to Exhibit 10.5 to Transocean Ltd.'s Current Report on Form 8-K filed on December 19, 2008)
	10.53	Drilling Contract between Vastar Resources, Inc. and R&B Falcon Drilling Co. dated December 9, 1998 with respect to *Deepwater Horizon*, as amended (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Quarterly Report on Form 10-Q (Commission File No. 000-53533) for the quarter ended June 30, 2010)
*	10.54	Executive Severance Benefit (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on February 23, 2012)
	10.55	Aker Drilling Pre-Acceptance Agreement (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on August 15, 2011)
	10.56	Form of Pre-Acceptance Commitment Letter (incorporated by reference to Exhibit 10.2 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on August 15, 2011)
*	10.57	Consulting Arrangement with Eric B. Brown (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on February 14, 2011)
*	10.58	Agreement with Gregory L. Cauthen (incorporated by reference to Exhibit 10.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on January 10, 2012)
†	21	Subsidiaries of Transocean Ltd.
†	23.1	Consent of Ernst & Young LLP
†	24	Powers of Attorney
†	31.1	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
†	31.2	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
†	32.1	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
†	32.2	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*	99.1	Deferred Prosecution Agreement by and between The United States Department of Justice, Transocean Inc. and Transocean Ltd (incorporated by reference to Exhibit 99.1 to Transocean Ltd.'s Current Report on Form 8-K (Commission File No. 000-53533) filed on November 5, 2010)
†	101.INS	XBRL Instance Document
†	101.SCH	XBRL Taxonomy Extension Schema
†	101.CAL	XBRL Taxonomy Extension Calculation Linkbase
†	101.DEF	XBRL Taxonomy Extension Definition Linkbase
†	101.LAB	XBRL Taxonomy Extension Label Linkbase
†	101.PRE	XBRL Taxonomy Extension Presentation Linkbase

† Filed herewith.
* Compensatory plan or arrangement.

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 27, 2012.

TRANSOCEAN LTD.
By /s/ Gregory L. Cauthen
Gregory L. Cauthen
Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on February 27, 2012.

Signature	Title
* J. Michael Talbert	Chairman of the Board of Directors
/s/ Steven L. Newman Steven L. Newman	President and Chief Executive Officer (Principal Executive Officer)
/s/ Gregory L. Cauthen Gregory L. Cauthen	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
Jagjeet S. Bindra	Director
* Thomas W. Cason	Director
* Tan Ek Kia	Director
* Steve Lucas	Director
* Martin B. McNamara	Director
* Edward R. Muller	Director
* Robert M. Sprague	Director
* Ian C. Strachan	Director

(Attorney-in-Fact)

Exhibit 31.1

CEO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven L. Newman, certify that:

1. I have reviewed this report on Form 10-K of Transocean Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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; and

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 27, 2012

/s/ Steven L. Newman
Steven L. Newman
President and Chief Executive Officer

Exhibit 31.2

CFO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory L. Cauthen, certify that:

1. I have reviewed this report on Form 10-K of Transocean Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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; and

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 27, 2012

/s/ Gregory L. Cauthen
Gregory L. Cauthen
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906 OF
THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b)
OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Steven L. Newman, President and Chief Executive Officer of Transocean Ltd., a Swiss corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2012

/s/ Steven L. Newman
Steven L. Newman
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO SECTION 906 OF
THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b)
OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Gregory L. Cauthen, Executive Vice President and Chief Financial Officer of Transocean Ltd., a Swiss corporation (the “Company”), hereby certify, to my knowledge, that:

(1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2011 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2012

/s/ Gregory L. Cauthen
Gregory L. Cauthen
Executive Vice President and Chief Financial Officer