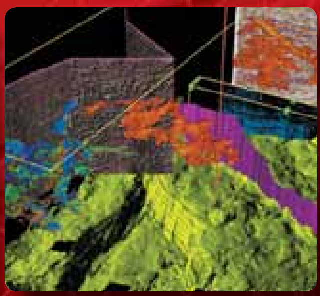
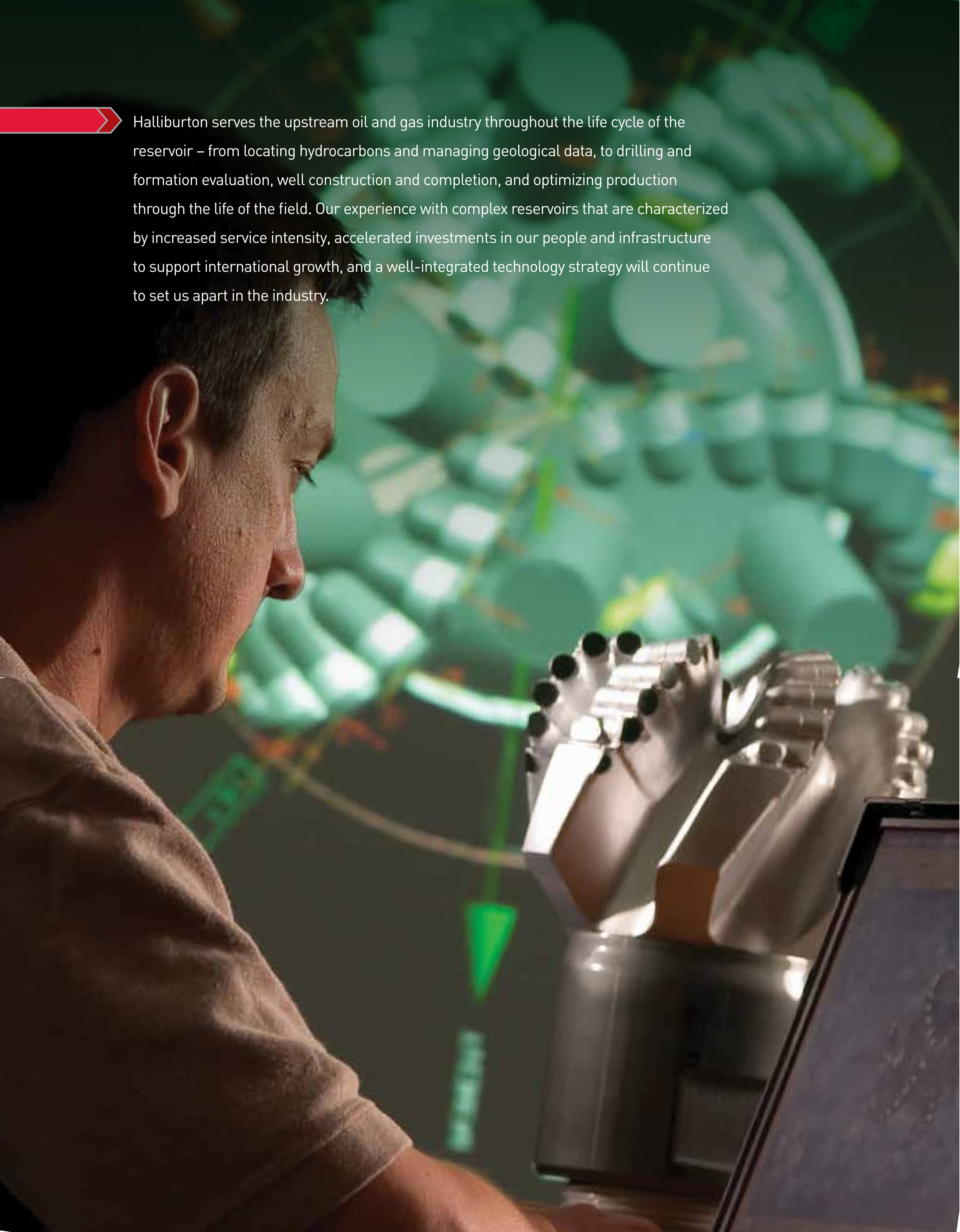
HALLIBURTON

2011 ANNUAL REPORT

ADVANCING TECHNOLOGY DELIVERING RESULTS


Halliburton serves the upstream oil and gas industry throughout the life cycle of the reservoir – from locating hydrocarbons and managing geological data, to drilling and formation evaluation, well construction and completion, and optimizing production through the life of the field. Our experience with complex reservoirs that are characterized by increased service intensity, accelerated investments in our people and infrastructure to support international growth, and a well-integrated technology strategy will continue to set us apart in the industry.

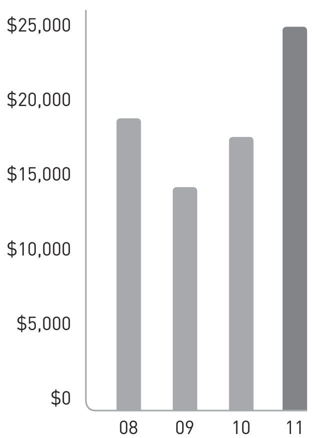


COMPARATIVE HIGHLIGHTS

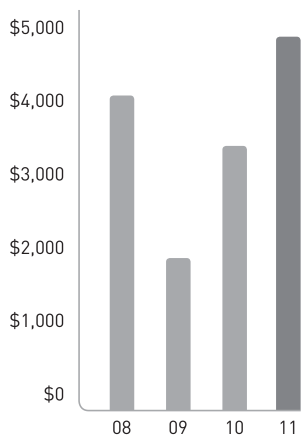
(MILLIONS OF DOLLARS AND SHARES, EXCEPT PER SHARE DATA)	**2011**	2010	2009	2008
Revenue	**$ 24,829**	$ 17,973	$ 14,675	$ 18,279
Operating income	**$ 4,737**	$ 3,009	$ 1,994	$ 4,010
Amounts attributable to company shareholders:				
Income from continuing operations	**$ 3,005**	$ 1,795	$ 1,154	$ 2,647
Net income	**$ 2,839**	$ 1,835	$ 1,145	$ 2,224
Diluted income per share attributable to company shareholders:				
Income from continuing operations	**$ 3.26**	$ 1.97	$ 1.28	$ 2.91
Net income	**$ 3.08**	$ 2.01	$ 1.27	$ 2.45
Cash dividends per share	**$ 0.36**	$ 0.36	$ 0.36	$ 0.36
Diluted weighted average common shares outstanding	**922**	911	902	909
Working capital (1)	**$ 7,456**	$ 6,129	$ 5,749	$ 4,630
Long-term debt (including current maturities)	**$ 4,820**	$ 3,824	$ 4,574	$ 2,612
Debt to total capitalization (2)	**27%**	27%	34%	25%
Capital expenditures	**$ 2,953**	$ 2,069	$ 1,864	$ 1,824
Depreciation, depletion and amortization	**$ 1,359**	$ 1,119	$ 931	$ 738
Return on capital employed (3)	**19%**	15%	11%	23%

(1) Calculated as current assets minus current liabilities
(2) Calculated as total debt divided by total debt plus shareholders' equity
(3) Calculated as net income attributable to company before interest expense divided by average capital employed. Capital employed includes total shareholders' equity and total debt.

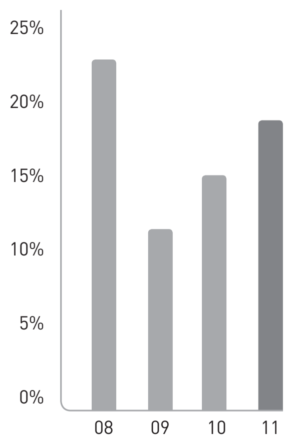
REVENUE in millions



OPERATING INCOME in millions



RETURN ON CAPITAL EMPLOYED



ADVANCING TECHNOLOGY

DELIVERING RESULTS

TO OUR SHAREHOLDERS:

We are very proud to report that 2011 was a highly successful year for our Company. Increased demand for our services and solid execution drove record revenues of $24.8 billion and operating income of $4.7 billion. We achieved return on average capital employed of 19 percent, revenue growth of 38 percent and operating income growth of 57 percent. Our growth, margins and returns in 2011 were superior to the financial results of our primary competitors.

The foundation of our successful strategy, based on leveraging three key market segments to drive superior growth, remains unchanged. We will continue to diligently pursue opportunities in unconventional plays, deepwater projects and mature fields.

LEADING IN UNCONVENTIONAL PLAYS Our technology leadership played a significant role in unconventional fields in 2011. We introduced our new RapidSuite™ sliding sleeve system, which provides our customers with a dramatic increase in efficiency in the completion of horizontal unconventional reservoirs.

We continued to deploy our CleanSuite™ technologies in 2011, a group of products and services designed to reduce the use of chemicals and water in hydraulic fracturing operations. The CleanSuite system represents our commitment to responsible energy development.

In the North America unconventional market, we have made great progress in deploying elements of our "Frac of the Future" strategic initiative to improve our capital and operational efficiency, such as our ADP™ advanced dry polymer blenders and SandCastle® proppant storage systems. Additionally, we are rolling out our first series of Q10™ pumps, which have demonstrated significant reliability and maintenance advantages in field testing over our current fleet, which is already generally considered to be the best in the industry. These new technologies are also delivering improvements in our environmental performance.

As the industry leader in unconventional shale plays, we performed the first shale fracture treatments in numerous countries around the globe, including Argentina, Mexico, Saudi Arabia, Australia, and Poland. Furthermore, customer consulting agreements have given us an opportunity to screen some 150 unconventional worldwide basins and perform over 60 detailed studies allowing us to enhance our understanding of global shale resources.

MAKING DEEPWATER ADVANCEMENTS In 2011, we broke ground at the construction site of our new technology center at the Federal University of Rio de Janeiro Technology Park. This groundbreaking event represents a milestone in the Technology Collaboration Agreement signed in 2009 between Halliburton and Petrobras for the purpose of providing deepwater research and technology development in Brazil and around the world.

We continued to invest in our deepwater business in 2011. Our wireline team advanced technology in deepwater, setting a new world record for hostile pressure testing and sampling operations. In addition, our Sperry Drilling product service line further solidified its leadership position in high-temperature drilling applications with its unique high-temperature motors and SOLAR™ Geo-Pilot® high-temperature rotary steerable system, which are unmatched in the industry today.



Technology permeates its way across all of our product service lines

During the year, we secured key deepwater contract wins in East Africa, Vietnam, Malaysia, Australia, China and Brazil, as well as other markets. We opened three new field offices in East Africa, setting the foundation for future activity in this important deepwater basin.

Our outstanding service quality continues to be recognized by our customers. We believe that our strengthening market position and service quality reputation will benefit us as newbuild deepwater rigs are deployed in 2012 and beyond.

MAXIMIZING MATURE-FIELD PERFORMANCE In mature fields, our new technologies are allowing our customers to improve their hydrocarbon recovery rates economically. Halliburton's Boots & Coots product service line offers a unique new service to help clients efficiently perform stimulation and remedial operations to enhance production in very long lateral wells. This PowerReach℠ service combines coiled tubing and jointed pipe to deliver game-changing technology in extended-reach applications.

Throughout 2011, we continued to build our capabilities to service mature fields, and we supported that effort with several acquisitions that enable us to broaden the scope of our mature-field offerings. The most significant of these was Multi-Chem, a premier provider of production and completion chemicals focused on production assurance throughout the life of our customers' wells. This acquisition will enable us to deliver additional value to our customers and shareholders as we expand the global footprint of this product line.

BUILDING RELATIONSHIPS, DELIVERING RESULTS Every day, our focus is on delivering results for our customers, and we believe that our performance was commendable in 2011. As proof of this, Halliburton was selected as one of seven world leaders out of 40 companies in the Dow Jones Sustainability Index, winning Best in Class for Human Capital Development, Standards for Suppliers, Corporate Governance, and Customer Relationship Management.

Looking forward, we continue to have a positive outlook for energy demand and related oilfield activity growth as our customers invest in their resources and optimize their development plans focused on increasingly complex projects. As such, we will continue expanding our capabilities and driving efficiency through technology and logistical improvements to enable this growth.

Finally, we would like to thank our board of directors, employees, customers, suppliers and shareholders who have enabled Halliburton to reach these new heights.

David J. Lesar
Chairman of the Board,
President and Chief Executive Officer

Albert O. Cornelison, Jr.
Executive Vice President and
General Counsel

Mark A. McCollum
Executive Vice President
and Chief Financial Officer

Timothy J. Probert
President, Strategy and
Corporate Development

ADVANCING TECHNOLOGY

IN UNCONVENTIONALS

DELIVERING RESULTS

Opportunity in Australia

With an estimated 396 trillion cubic feet of technically recoverable natural gas in Australia, Halliburton is currently supporting our customers' exploration programs for shale, tight gas and coal seam gas in this promising region. In contrast to North America, international markets have restricted access to the capital required for unconventional development. Halliburton continues to accelerate the transfer of equipment to international markets to meet customer demand.

RAPIDSUITE™ SYSTEM In unconventional fields, our RapidSuite™ system provides operators new options for completing horizontal multi-zone wellbores to enable highly accurate placement of fractures. This innovative ball-activated technology allows for continuous pumping over multiple zones, reducing completion times by 50 percent or more while reducing water requirements. Halliburton has successfully delivered this integrated technology in the Permian and Williston basins, in South Texas and in unconventional plays internationally.

CLEANSUITE™ SYSTEM TECHNOLOGIES Halliburton provides engineering solutions that set new standards for environmental safety while helping our customers do more with less. Our CleanSuite™ technologies include three "green" Halliburton proprietary completion technologies for both hydraulic fracturing and water treatment.

Our **CleanStream®** service technology dramatically reduces the volume of conventional biocides required, through treatment with ultraviolet light. We treated more than a billion gallons of fracturing fluid in 2011, substantially reducing the volume of biocides needed to be transported and consumed.

The **CleanWave®** water treatment system is a mobile service for recycling produced and flowback water. The system uses an electrical process to remove unwanted suspended contaminants in water, quickly preparing it for reuse.

Our **CleanStim®** fracturing service uses a new fracturing fluid formulation made with ingredients exclusively sourced from the food industry. In addition to environmental benefits, the CleanStim fluid system provides excellent performance in terms of production over the life of the well.

These CleanSuite technologies and our "Frac of the Future" developments, which improve our operational and capital efficiency, will be instrumental in ensuring development of unconventional resources in increasingly efficient ways in North America and emerging international markets. We have great enthusiasm for international development, and believe that our unique technology, global footprint and track record of execution make us very well positioned as these markets grow.

As part of our CleanSuite™ technologies, Halliburton's mobile CleanStream® service uses ultraviolet light to reduce bacteria by up to 99.9 percent, dramatically decreasing the volume of biocides needed in fracturing operations.

Halliburton's CleanStream® service treated over a billion gallons of hydraulic fracturing fluid in 2011.

ADVANCING TECHNOLOGY

IN DEEP WATER

MEETING THE DEEPWATER CHALLENGE Deepwater exploration and development present some of the industry's biggest challenges and greatest potential rewards. Operators are increasingly turning their attention to unexplored or underdeveloped deepwater areas to access additional hydrocarbon resources. High temperatures and/or high pressures are often found in these uncharted territories, presenting complex and unique challenges. Halliburton has invested heavily in research and development to deliver tools and technologies for deepwater wells in increasingly deeper, hotter and higher-pressure environments.

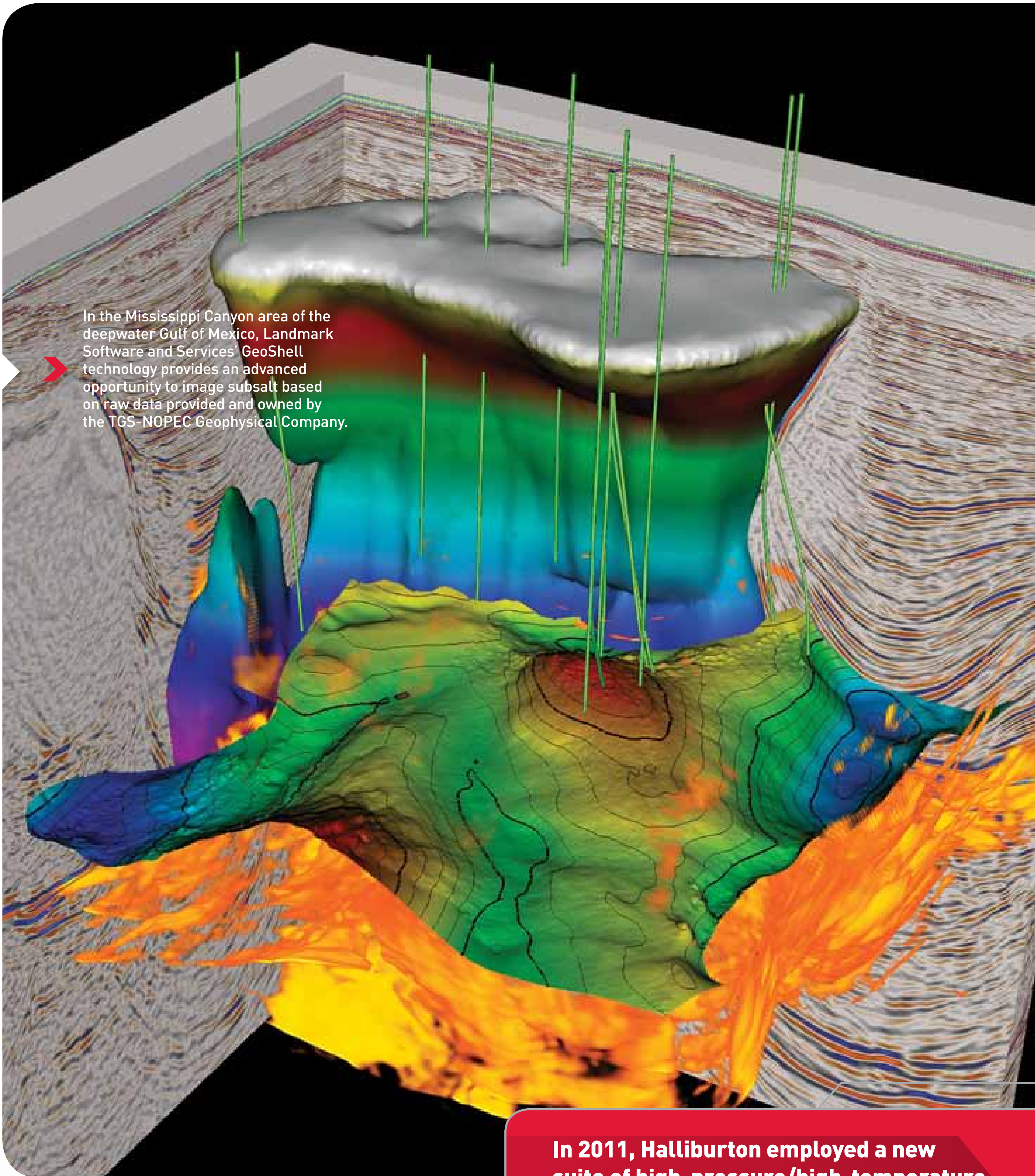
DRILLING ADVANCES Our Sperry Drilling product service line has an unmatched offering in high-temperature drilling with its unique high-temperature motors and SOLAR™ Geo-Pilot® high-temperature rotary steerable system. Sperry has also successfully deployed the 24-inch Geo-Pilot system, which broadens our capabilities in deep water. Furthermore, it has delivered record performances with no nonproductive time during Geo-Pilot GXT rotary steerable runs in both Australia and the North Sea. Sperry has also added extreme high-temperature directional capability through the acquisition of TurboPower, resulting in the most comprehensive portfolio of high-temperature drilling tools in the industry.

FORMATION EVALUATION ADVANCES In 2011, Sperry Drilling completed successful field testing of the GeoTap® IDS sensor, which, deployed via a logging-while-drilling (LWD) assembly, takes fluid samples and pressure tests during the drilling process, thus avoiding the requirement for costly wireline sampling runs after the well is drilled. During field testing, the customer drilled for six days with the tool while capturing more than 50 formation pressure and fluid tests. This resulted in almost 80 hours of rig time saved and the cancellation of a competitor's wireline job. With the GeoTap IDS sensor, samples were taken within hours of drilling the formation, reducing the likelihood of borehole damage and producing a less-contaminated sample. Sperry also successfully field tested its XBAT™ sonic tool, the first acoustic LWD tool to produce azimuthal images of the formation, enabling real-time geosteering to ensure accurate well placement. Both of these technologies enable operators to make decisions more quickly while minimizing risk and saving drilling time.

DELIVERING RESULTS

An Industry First for Logging While Drilling

Our GeoTap® IDS sensor is revolutionizing the industry by allowing downhole capture, identification and surface recovery of representative fluid samples during the drilling process. Built on the acclaimed GeoTap formation pressure tester platform, the GeoTap IDS sensor delivers real-time reservoir characterization and helps eliminate the time and cost of wireline sampling.



In the Mississippi Canyon area of the deepwater Gulf of Mexico, Landmark Software and Services' GeoShell technology provides an advanced opportunity to image subsalt based on raw data provided and owned by the TGS-NOPEC Geophysical Company.

In 2011, Halliburton employed a new suite of high-pressure/high-temperature tools at a record temperature of 450 degrees Fahrenheit.

ADVANCING TECHNOLOGY

IN MATURE FIELDS

DELIVERING RESULTS

Remolino Lab Project

Improved subsurface understanding is often the key to enhanced performance. In the Remolino Field Lab in Mexico, we began a unique collaboration arrangement with our customer designed to materially enhance the production rate of newly drilled wells in the Chicontepec field. In December 2011, in partnership with our customer, Halliburton designed, drilled and completed well PA-1565 with a "maximum reservoir contact" horizontal design. It had an initial production rate of 3,800 barrels per day, many times greater than the average production rate of a typical well in the Chicontepec field. This single well has produced the equivalent of more than 20 conventional wells in the field.

EXPANDING OUR MATURE-FIELD STRATEGY Mature fields account for more than 70 percent of the world's oil and natural gas production, with an approximate average recovery factor of just 35 percent. It is estimated that a 1 percent increase in the global recovery factor would add the equivalent of two years of global production to the reserve base, creating an enormous opportunity for the industry. Halliburton is successfully challenging conventional thinking that enhanced recovery activities are too costly and are, therefore, uneconomic in many less-prolific fields. In partnership with our customers, we are deploying innovative technologies to help mature fields realize their full potential.

DELIVERING RESULTS THROUGH OUR CONSULTING SERVICES The application of new evaluation tools and technology to better characterize the subsurface of mature fields is often a first step in their redevelopment. Our team of experienced consultants provides analysis of complex mature reservoirs and develops technology recommendations, which Halliburton is capable of delivering to help our customers meet their goals. In one project, by following Halliburton's recommendation, our customer saw an increase in its expected recovery rate from 8 percent to 40 percent while reducing the level of associated water production. The value of the increased production covered the cost of this work in just two months.

Our acquisition of Multi-Chem in 2011 further strengthened Halliburton's capability to provide production assurance services to our customers in mature fields. Multi-Chem is the fourth-largest provider of production chemicals in North America, and it is aggressively expanding its presence in international markets. Multi-Chem delivers specialty chemicals – including environmentally conscious chemicals, services and solutions – to help oil and natural gas companies assure their production in more than 30,000 oil and natural gas wells around the world.

We are committed to research and development as an enabler of future growth. In a lab, a researcher works in a glove box to safely handle nano-particle materials, an increasingly important component of drilling fluids, specialty chemicals and other products.

The Multi-Chem acquisition enhances our capabilities in mature fields.

HALLIBURTON | 2011 FORM 10-K

ADVANCING TECHNOLOGY
DELIVERING RESULTS

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
[X] 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 001-03492

HALLIBURTON COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**75-2677995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000 North Sam Houston Parkway East
Houston, Texas 77032
(Address of principal executive offices)
Telephone Number – Area code (281) 871-2699

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock par value $2.50 per share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

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

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 [X] 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. [X]

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

Large accelerated filer	[X]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]

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

The aggregate market value of Common Stock held by nonaffiliates on June 30, 2011, determined using the per share closing price on the New York Stock Exchange Composite tape of $51.00 on that date, was approximately $46,721,000,000.

As of February 10, 2012, there were 922,983,220 shares of Halliburton Company Common Stock, $2.50 par value per share, outstanding.

Portions of the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 001-03492) are incorporated by reference into Part III of this report.

HALLIBURTON COMPANY
Index to Form 10-K
For the Year Ended December 31, 2011

PART I

Item 1. Business.

General description of business

Halliburton Company's predecessor was established in 1919 and incorporated under the laws of the State of Delaware in 1924. We are a leading provider of services and products to the energy industry related to the exploration, development, and production of oil and natural gas. We serve major, national, and independent oil and natural gas companies throughout the world and operate under two divisions, which form the basis for the two operating segments we report, Completion and Production segment and Drilling and Evaluation segment:

- our Completion and Production segment delivers cementing, stimulation, intervention, pressure control, specialty chemicals, artificial lift, and completion services. The segment consists of Halliburton Production Enhancement, Cementing, Completion Tools, Boots & Coots, and Multi-Chem; and
- our Drilling and Evaluation segment provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, and optimize their well construction activities. The segment consists of Halliburton Drill Bits and Services, Wireline & Perforating, Testing and Subsea, Baroid, Sperry Drilling, Landmark Software and Services, and Halliburton Consulting and Project Management.

See Note 2 to the consolidated financial statements for further financial information related to each of our business segments and a description of the services and products provided by each segment. We have significant manufacturing operations in various locations, including, but not limited to, the United States, Canada, the United Kingdom, Malaysia, Mexico, Brazil, and Singapore.

Business strategy

Our business strategy is to secure a distinct and sustainable competitive position as an oilfield service company by delivering services and products to our customers that maximize their production and recovery and realize proven reserves from difficult environments. Our objectives are to:

- create a balanced portfolio of services and products supported by global infrastructure and anchored by technological innovation with a well-integrated digital strategy to further differentiate our company;
- reach a distinguished level of operational excellence that reduces costs and creates real value from everything we do;
- preserve a dynamic workforce by being a preferred employer to attract, develop, and retain the best global talent; and
- uphold the ethical and business standards of the company and maintain the highest standards of health, safety, and environmental performance.

Markets and competition

We are one of the world's largest diversified energy services companies. Our services and products are sold in highly competitive markets throughout the world. Competitive factors impacting sales of our services and products include:

- price;
- service delivery (including the ability to deliver services and products on an "as needed, where needed" basis);
- health, safety, and environmental standards and practices;
- service quality;
- global talent retention;
- understanding of the geological characteristics of the hydrocarbon reservoir;
- product quality;
- warranty; and
- technical proficiency.

We conduct business worldwide in approximately 80 countries. The business operations of our divisions are organized around four primary geographic regions: North America, Latin America, Europe/Africa/CIS, and Middle East/Asia. In 2011, based on the location of services provided and products sold, 55% of our consolidated revenue was from the United States. In 2010 and 2009, 46% and 36% of our consolidated revenue was from the United States. No other country accounted for more than 10% of our consolidated revenue during these periods. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations" and Note 2 to the consolidated financial statements for additional financial information about geographic operations in the last three years. Because the markets for our services and products are vast and cross numerous geographic lines, a meaningful estimate of the total number of competitors cannot be made. The industries we serve are highly competitive, and we have many substantial competitors. Most of our services and products are marketed through our servicing and sales organizations.

Operations in some countries may be adversely affected by unsettled political conditions, acts of terrorism, civil unrest, expropriation or other governmental actions, foreign currency exchange restrictions, and highly inflationary currencies. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country, other than the United States, would be material to the conduct of our operations taken as a whole.

Information regarding our exposure to foreign currency fluctuations, risk concentration, and financial instruments used to minimize risk is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Instrument Market Risk" and in Note 12 to the consolidated financial statements.

Customers

Our revenue from continuing operations during the past three years was derived from the sale of services and products to the energy industry. No customer represented more than 10% of consolidated revenue in any period presented.

Raw materials

Raw materials essential to our business are normally readily available. Market conditions can trigger constraints in the supply of certain raw materials, such as gel, proppants, and hydrochloric acid. We are always seeking ways to ensure the availability of resources, as well as manage costs of raw materials. Our procurement department uses our size and buying power to ensure that we have access to key materials at competitive prices.

Research and development costs

We maintain an active research and development program. The program improves products, processes, and engineering standards and practices that serve the changing needs of our customers, such as those related to high pressure/high temperature environments, and also develops new products and processes. Our expenditures for research and development activities were $401 million in 2011, $366 million in 2010, and $325 million in 2009, of which over 96% was company-sponsored in each year.

Patents

We own a large number of patents and have pending a substantial number of patent applications covering various products and processes. We are also licensed to utilize patents owned by others. We do not consider any particular patent to be material to our business operations.

Seasonality

Weather and natural phenomena can temporarily affect the performance of our services, but the widespread geographical locations of our operations mitigate those effects. Examples of how weather can impact our business include:

- the severity and duration of the winter in North America can have a significant impact on natural gas storage levels and drilling activity;
- the timing and duration of the spring thaw in Canada directly affects activity levels due to road restrictions;
- typhoons and hurricanes can disrupt coastal and offshore operations; and
- severe weather during the winter months normally results in reduced activity levels in the North Sea and Russia.

Additionally, customer spending patterns for software and various other oilfield services and products can result in higher activity in the fourth quarter of the year.

Employees

At December 31, 2011, we employed approximately 68,000 people worldwide compared to approximately 58,000 at December 31, 2010. At December 31, 2011, approximately 15% of our employees were subject to collective bargaining agreements. Based upon the geographic diversification of these employees, we do not believe any risk of loss from employee strikes or other collective actions would be material to the conduct of our operations taken as a whole.

Environmental regulation

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. For further information related to environmental matters and regulation, see Note 8 to the consolidated financial statements, Item 1(a), “Risk Factors,” and Item 3, “Legal Proceedings.”

Hydraulic fracturing process

Hydraulic fracturing is a process that creates fractures extending from the well bore through the rock formation to enable natural gas or oil to move more easily through the rock pores to a production well. A significant portion of our Completion and Production segment provides hydraulic fracturing services to customers developing shale natural gas and shale oil. In recent months, questions have arisen about the scope of our operations in the shale natural gas and shale oil sectors, and the extent to which these operations may affect human health and the environment.

We generally design and implement a hydraulic fracturing operation to “stimulate” the well, at the direction of our customer, once the well has been drilled, cased, and cemented. Our customer is generally responsible for providing the base fluid (usually water) used in the hydraulic fracturing of a well. We supply the proppant (often sand) and any additives used in the overall fracturing fluid mixture. In addition, we mix the additives and proppant with the base fluid and pump the mixture down the wellbore to create the desired fractures in the target formation. The customer is responsible for disposing of any materials that are subsequently pumped out of the well, including flowback fluids and produced water.

As part of the process of constructing the well, the customer will take a number of steps designed to protect drinking water resources. In particular, the casing and cementing of the well are designed to provide "zonal isolation" so that the fluids pumped down the wellbore and the oil and natural gas and other materials that are subsequently pumped out of the well will not come into contact with shallow aquifers or other shallow formations through which those materials could potentially migrate to the surface.

The potential environmental impacts of hydraulic fracturing have been studied by numerous government entities and others. In 2004, EPA conducted an extensive study of hydraulic fracturing practices, focusing on coalbed methane wells, and their potential effect on underground sources of drinking water. The EPA's study concluded that hydraulic fracturing of coalbed methane wells poses little or no threat to underground sources of drinking water. At the request of Congress, the EPA is currently undertaking another study of the relationship between hydraulic fracturing and drinking water resources that will focus on the fracturing of shale natural gas wells.

We have made detailed information regarding our fracturing fluid composition and breakdown available on our internet web site at www.halliburton.com. We also have proactively developed processes to provide our customers with the chemical constituents of our hydraulic fracturing fluids to enable our customers to comply with state laws as well as voluntary standards established by the Chemical Disclosure Registry, www.fracfocus.org.

At the same time, we have invested considerable resources in developing our CleanSuite™ hydraulic fracturing technologies, which offer our customers a variety of environmental friendly alternatives related to the use of hydraulic fracturing fluid additives and other aspects of our hydraulic fracturing operations. We created a hydraulic fracturing fluid system comprised of materials sourced entirely from the food industry. In addition, we have engineered a process to control the growth of bacteria in hydraulic fracturing fluids that uses ultraviolet light, allowing customers to minimize the use of chemical biocides. We are committed to the continued development of innovative chemical and mechanical technologies that allow for more economical and environmentally friendly development of the world's oil and natural gas reserves.

In evaluating any environmental risks that may be associated with our hydraulic fracturing services, it is helpful to understand the role that we play in the development of shale natural gas and shale oil. Our principal task generally is to manage the process of injecting fracturing fluids into the borehole to "stimulate" the well. Thus, based on the provisions in our contracts and applicable law, the primary environmental risks we face are potential pre-injection spills or releases of stored fracturing fluids and spills or releases of fuel or other fluids associated with pumps, blenders, conveyors, or other above-ground equipment used in the hydraulic fracturing process.

Although possible concerns have been raised about hydraulic fracturing operations, the circumstances described above have helped to mitigate those concerns. To date, we have not been obligated to compensate any indemnified party for any environmental liability arising directly from hydraulic fracturing, although there can be no assurance that such obligations or liabilities will not arise in the future.

Working capital

We fund our business operations through a combination of available cash and equivalents, short-term investments, and cash flow generated from operations. In addition, our revolving credit facility is available for additional working capital needs.

Web site access

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act of 1934 are made available free of charge on our internet web site at www.halliburton.com as soon as reasonably practicable after we have electronically filed the material with, or furnished it to, the Securities and Exchange Commission (SEC). The public may read and copy any materials we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains our reports, proxy and information statements, and our other SEC filings. The address of that site is www.sec.gov. We have posted on our web site our Code of Business Conduct, which applies to all of our employees and Directors and serves as a code of ethics for our principal executive officer, principal financial officer, principal accounting officer, and other persons performing similar functions. Any amendments to our Code of Business Conduct or any waivers from provisions of our Code of Business Conduct granted to the specified officers above are disclosed on our web site within four business days after the date of any amendment or waiver pertaining to these officers. There have been no waivers from provisions of our Code of Business Conduct for the years 2011, 2010, or 2009. Except to the extent expressly stated otherwise, information contained on or accessible from our web site or any other web site is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report.

Executive Officers of the Registrant

The following table indicates the names and ages of the executive officers of Halliburton Company as of February 10, 2012, including all offices and positions held by each in the past five years:

	Name and Age	Offices Held and Term of Office
	Joseph F. Andolino (Age 58)	Senior Vice President, Tax of Halliburton Company, since January 2011 Vice President, Business Development of Goodrich Corporation, January 2009 to December 2010 Vice President, Tax and Business Development of Goodrich Corporation, November 1999 to December 2008
	Evelyn M. Angelle (Age 44)	Senior Vice President and Chief Accounting Officer of Halliburton Company, since January 2011 Vice President, Corporate Controller, and Principal Accounting Officer of Halliburton Company, January 2008 to January 2011 Vice President, Operations Finance of Halliburton Company, December 2007 to January 2008 Vice President, Investor Relations of Halliburton Company, April 2005 to November 2007
	James S. Brown (Age 57)	President, Western Hemisphere of Halliburton Company, since January 2008 Senior Vice President, Western Hemisphere of Halliburton Company, June 2006 to December 2007
*	Albert O. Cornelison, Jr. (Age 62)	Executive Vice President and General Counsel of Halliburton Company, since December 2002
	Christian A. Garcia (Age 48)	Senior Vice President and Treasurer of Halliburton Company, since September 2011 Senior Vice President, Investor Relations of Halliburton Company, January 2011 to August 2011 Vice President, Investor Relations of Halliburton Company, December 2007 to December 2010 Vice President, Operations Finance, July 2006 to December 2007
*	David J. Lesar (Age 58)	Chairman of the Board, President, and Chief Executive Officer of Halliburton Company, since August 2000
*	Mark A. McCollum (Age 52)	Executive Vice President and Chief Financial Officer of Halliburton Company, since January 2008 Senior Vice President and Chief Accounting Officer of Halliburton Company, August 2003 to December 2007

Name and Age	Offices Held and Term of Office
* Lawrence J. Pope (Age 43)	Executive Vice President of Administration and Chief Human Resources Officer of Halliburton Company, since January 2008 Vice President, Human Resources and Administration of Halliburton Company, January 2006 to December 2007
* Timothy J. Probert (Age 60)	President, Strategy and Corporate Development of Halliburton Company, since January 2011 President, Global Business Lines and Corporate Development of Halliburton Company, January 2010 to January 2011 President, Drilling and Evaluation Division and Corporate Development of Halliburton Company, March 2009 to December 2009 Executive Vice President, Strategy and Corporate Development of Halliburton Company, January 2008 to March 2009 Senior Vice President, Drilling and Evaluation of Halliburton Company, July 2007 to December 2007 Senior Vice President, Drilling and Evaluation and Digital Solutions of Halliburton Company, May 2006 to July 2007
Joe D. Rainey (Age 55)	President, Eastern Hemisphere of Halliburton Company, since January 2011 Senior Vice President, Eastern Hemisphere of Halliburton Company, January 2010 to December 2010 Vice President, Eurasia Pacific Region of Halliburton Company, January 2009 to December 2009 Vice President, Asia Pacific Region of Halliburton Company, February 2005 to December 2008

* Members of the Policy Committee of the registrant.

There are no family relationships between the executive officers of the registrant or between any director and any executive officer of the registrant.

Item 1(a). Risk Factors.

The statements in this section describe the known material risks to our business and should be considered carefully.

We, among others, have been named as a defendant in numerous lawsuits and are the subject of numerous investigations relating to the Macondo well incident that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for BP Exploration & Production, Inc. (BP Exploration), the lease operator and indirect wholly owned subsidiary of BP p.l.c. (BP p.l.c., BP Exploration, and their affiliates, collectively, BP). There were eleven fatalities and a number of injuries as a result of the Macondo well incident. Crude oil escaping from the Macondo well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services.

We are named along with other unaffiliated defendants in more than 400 complaints, most of which are alleged class-actions, involving pollution damage claims and at least nine personal injury lawsuits involving four decedents and at least 21 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. BP Exploration and one of its affiliates have filed claims against us seeking subrogation and contribution, including with respect to liabilities under the Oil Pollution Act of 1990 (OPA), and direct damages, and alleging negligence, gross negligence, fraudulent conduct and fraudulent concealment. Certain other defendants in the lawsuits have filed claims against us seeking, among other things, indemnification and contribution, including with respect to liabilities under the OPA, and alleging, among other things, negligence and gross negligence. See Part I, Item 3, "Legal Proceedings." Additional lawsuits may be filed against us, including criminal and civil charges under federal and state statutes and regulations. Those statutes and regulations could result in criminal penalties, including fines and imprisonment, as well as civil fines, and the degree of the penalties and fines may depend on the type of conduct and level of culpability, including strict liability, negligence, gross negligence, and knowing violations of the statute or regulation.

In addition to the claims and lawsuits described above, numerous industry participants, governmental agencies and Congressional committees have investigated or are investigating the cause of the explosion, fire, and resulting oil spill. According to the January 11, 2011 report (Investigation Report) of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report states that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report also identified the failure of BP's and our processes for cement testing and communication failures among BP, Transocean, and us with respect to the difficulty of the cement job as examples of systemic failures by industry management.

In September 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) released the final report of the Marine Board Investigation regarding the Macondo well incident (BOEMRE Report). A panel of investigators of the BOEMRE identified a number of causes of the Macondo well incident. According to the BOEMRE Report, “a central cause of the blowout was failure of a cement barrier in the production casing string.” The panel was unable to identify the precise reasons for the failure but concluded that it was likely due to: “(1) swapping of cement and drilling mud in the shoe track (the section of casing near the bottom of the well); (2) contamination of the shoe track cement; or (3) pumping the cement past the target location in the well, leaving the shoe track with little or no cement.” Generally, the panel concluded that the Macondo well incident was the result of, among other things, poor risk management, last-minute changes to drilling plans, failure to observe and respond to critical indicators, and inadequate well control response by the companies and individuals involved.

The BOEMRE Report also stated, among other things, that BP failed to properly communicate well design and cementing decisions and risks to Transocean, that BP and Transocean failed to correctly interpret the negative-pressure test, and that we, BP, and Transocean failed to detect the influx of hydrocarbons into the well. According to the BOEMRE Report, the panel found evidence that we, among others, violated federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the well under control, and the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico. In October 2011, the Bureau of Safety and Environmental Enforcement (BSEE) issued a notification of Incidents of Noncompliance (INCs) to us for violating those regulations and a federal regulation relating to the failure to protect health, safety, property, and the environment as a result of a failure to perform operations in a safe and workmanlike manner. According to the BSEE’s notice, we did not ensure an adequate barrier to hydrocarbon flow after cementing the production casing and did not detect the influx of hydrocarbons until they were above the blowout preventer stack. We understand that the regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation. We have appealed the INCs to, and the appeal was accepted by, the Interior Board of Land Appeals (IBLA). In January 2012, the IBLA, in response to our and the BSEE’s joint request, has suspended the appeal and has ordered us and the BSEE to file notice within 15 days after the conclusion of the multi-district litigation (MDL) and, within 60 days after the MDL court issues a final decision, to file a proposal for further action in the appeal. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal period has ended. The BSEE has stated that this is the first time the Department of the Interior has issued INCs directly to a contractor that was not the well’s operator. We have not accrued any amounts related to the INCs.

Various other investigations have or may be critical of the services we provided on the Deepwater Horizon. In addition, as part of its criminal investigation, the Department of Justice (DOJ) is examining certain aspects of our conduct after the incident, including with respect to record-keeping, record retention, post-incident testing, securities filings, and public statements by us or our employees, to evaluate whether there has been any violation of federal law.

Our contract with BP Exploration relating to the Macondo well generally provides for our indemnification for certain potential claims and expenses relating to the Macondo well incident. BP Exploration, in connection with filing its claims with respect to the MDL proceeding, sought to avoid their indemnity obligations and asked the court to declare that it is not liable to us in contribution, indemnification or otherwise with respect to liabilities arising from the Macondo well incident. Other defendants in the litigation have generally denied any obligation to contribute to any liabilities arising from the Macondo well incident. In January 2012, the court in the MDL proceeding entered an order in response to our and BP's motions for summary judgment regarding certain indemnification matters. The court held that BP is required to indemnify us for third-party compensatory claims, or actual damages, that arise from pollution or contamination that did not originate from our property or equipment located above the surface of the land or water, even if we are found to be grossly negligent. The court also held that BP does not owe us indemnity for punitive damages or for civil penalties under the Clean Water Act (CWA), if any, and that fraud could void the indemnity on public policy grounds. The court in the MDL proceeding deferred ruling on whether our indemnification from BP covers penalties or fines under the Outer Continental Shelf Lands Act, whether our alleged breach of our contract with BP Exploration would invalidate the indemnity, and whether we committed an act that materially increased the risk to or prejudiced the rights of BP so as to invalidate the indemnity.

The rulings in the MDL proceeding regarding the indemnities are based on maritime law and may not bind the determination of similar issues in lawsuits not comprising a part of the MDL proceedings. Accordingly it is possible that different conclusions with respect to indemnities will be reached by other courts.

Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. In addition, certain state laws, if deemed to apply, would not allow for enforcement of indemnification for gross negligence, and may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims.

Financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. BP's public filings indicate that BP has recognized in excess of $40 billion in pre-tax charges, excluding offsets for settlement payments received from certain defendants in the MDL, as a result of the Macondo well incident. BP's public filings also indicate that the amount of, among other things, certain natural resource damages with respect to certain OPA claims, some of which may be included in such charges, cannot be reliably estimated as of the dates of those filings. If BP Exploration filed for bankruptcy protection, a bankruptcy judge could disallow our contract with BP Exploration, including the indemnification obligations thereunder. Also, we may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies.

We are currently unable to estimate the impact the Macondo well incident will have on us. We cannot predict the outcome of the many lawsuits and investigations relating to the Macondo well incident, including whether the MDL will proceed to trial, the results of any such trial, or whether we might settle with one or more of the parties to any lawsuit or investigation. Given the numerous potential future developments relating to the MDL and other lawsuits and investigations, we are unable to conclude whether we will incur a loss. As of December 31, 2011, we have not accrued any amounts related to this matter because we have not determined that a loss is probable and a reasonable estimate of a loss or range of loss related to this matter cannot be made. As a result of any future developments, some of which could occur as soon as within the next few months, we may adjust our liability assessment, and liabilities arising out of this matter could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Certain matters relating to the Macondo well incident, including increased regulation of the United States offshore drilling industry, and similar catastrophic events could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Results of the Macondo well incident and the subsequent oil spill have included offshore drilling delays and increased federal regulation of our and our customers' operations, and more delays and regulations are expected. For example, the Investigation Report and other investigative reports recommended, among other things, a review of and numerous changes to drilling and environmental regulations and, in some cases, the creation of new, independent agencies to oversee the various aspects of offshore drilling. Two new, independent agencies, the BSEE and the Bureau of Ocean Energy Management (BOEM), replaced the BOEMRE effective October 2011. Since the Macondo well incident, the BSEE has issued guidance and regulations for drillers that intend to resume deepwater drilling activity. The BSEE's regulations focus in part on increased safety and environmental issues, drilling equipment, and the requirement that operators submit drilling applications demonstrating regulatory compliance with respect to, among other things, required independent third-party inspections, certification of well design and well control equipment and emergency response plans in the event of a blowout. The BSEE has also proposed additional regulations with respect to increased employee involvement in certain safety measures and third-party audits of an operator's safety and environmental management system program. The BSEE has stated that it will also make available for public comment additional proposed regulations based on the BOEMRE Report. In addition, the BSEE has stated that it has concluded that it has the legal authority to extend its regulatory reach to include contractors, like us, in addition to operators, as evidenced by the INCs. In addition, the BSEE has suggested that a legislative increase of the maximum rate for applicable civil penalties is necessary.

The increased regulation of the exploration and production industry as a whole that arises out of the Macondo well incident has and could continue to result in higher operating costs for us and our customers, extended permitting and drilling delays, and reduced demand for our services. We cannot predict to what extent increased regulation may be adopted in international or other jurisdictions or whether we and our customers will be required or may elect to implement responsive policies and procedures in jurisdictions where they may not be required.

In addition, the Macondo well incident has negatively impacted and could continue to negatively impact the availability and cost of insurance coverage for us, our customers and our and their service providers. Also, our relationships with BP and others involved in the Macondo well incident could be negatively affected. Our business may be adversely impacted by any negative publicity relating to the incident, any negative perceptions about us by our customers, any increases in insurance premiums or difficulty in obtaining coverage, and the diversion of management's attention from our operations to focus on matters relating to the incident.

As illustrated by the Macondo well incident, the services we provide for our customers are performed in challenging environments that can be dangerous. Catastrophic events such as a well blowout, fire, or explosion can occur, resulting in property damage, personal injury, death, pollution, and environmental damage. While we are typically indemnified by our customers for these types of events and the resulting damages and injuries (except in some cases, claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment), we will be exposed to significant potential losses should such catastrophic events occur if adequate indemnification provisions or insurance arrangements are not in place, if existing indemnity or related release from liability provisions are determined by a court to be unenforceable or otherwise invalid, in whole or in part, or if our customers are unable or unwilling to satisfy their indemnity obligations.

The matters discussed above relating to the Macondo well incident and similar catastrophic events could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Our operations are subject to political and economic instability and risk of government actions that could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

We are exposed to risks inherent in doing business in each of the countries in which we operate. Our operations are subject to various risks unique to each country that could have a material adverse effect on our consolidated results of operations and consolidated financial condition. With respect to any particular country, these risks may include:

- political and economic instability, including:
  - civil unrest, acts of terrorism, force majeure, war, or other armed conflict;
  - inflation; and
  - currency fluctuations, devaluations, and conversion restrictions; and
- governmental actions that may:
  - result in expropriation and nationalization of our assets in that country;
  - result in confiscatory taxation or other adverse tax policies;
  - limit or disrupt markets, restrict payments, or limit the movement of funds;
  - result in the deprivation of contract rights; and
  - result in the inability to obtain or retain licenses required for operation.

For example, due to the unsettled political conditions in many oil-producing countries, our operations, revenue, and profits are subject to the adverse consequences of war, the effects of terrorism, civil unrest, strikes, currency controls, and governmental actions. These and other risks described above could result in the loss of our personnel or assets, cause us to evacuate our personnel from certain countries, cause us to increase spending on security worldwide, disrupt financial and commercial markets, including the supply of and pricing for oil and natural gas, and generate greater political and economic instability in some of the geographic areas in which we operate. Areas where we operate that have significant risk include, but are not limited to: the Middle East, North Africa, Azerbaijan, Colombia, Indonesia, Kazakhstan, Mexico, Nigeria, Russia, and Venezuela. In addition, any possible reprisals as a consequence of military or other action, such as acts of terrorism in the United States or elsewhere, could have a material adverse effect on our business and consolidated results of operations.

Our operations outside the United States require us to comply with a number of United States and international regulations, violations of which could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Our operations outside the United States require us to comply with a number of United States and international regulations. For example, our operations in countries outside the United States are subject to the United States Foreign Corrupt Practices Act (FCPA), which prohibits United States companies and their agents and employees from providing anything of value to a foreign official for the purposes of influencing any act or decision of these individuals in their official capacity to help obtain or retain business, direct business to any person or corporate entity, or obtain any unfair advantage. Our activities create the risk of unauthorized payments or offers of payments by one of our employees, agents, or joint venture partners that could be in violation of the FCPA, even though these parties are not subject to our control. We have internal control policies and procedures and have implemented training and compliance programs for our employees and agents with respect to the FCPA. However, we cannot assure that our policies, procedures, and programs always will protect us from reckless or criminal acts committed by our employees or agents. Allegations of violations of applicable anti-corruption laws, including the FCPA, may result in internal, independent, or government investigations. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition. In addition, investigations by governmental authorities as well as legal, social, economic, and political issues in these countries could have a material adverse effect on our business and consolidated results of operations. We are also subject to the risks that our employees, joint venture partners, and agents outside of the United States may fail to comply with other applicable laws.

Changes in or interpretation of tax law and currency/repatriation control could impact the determination of our income tax liabilities for a tax year.

We have operations in approximately 80 countries other than the United States. Consequently, we are subject to the jurisdiction of a significant number of taxing authorities. The income earned in these various jurisdictions is taxed on differing bases, including net income actually earned, net income deemed earned, and revenue-based tax withholding. The final determination of our income tax liabilities involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction, as well as the significant use of estimates and assumptions regarding the scope of future operations and results achieved and the timing and nature of income earned and expenditures incurred. Changes in the operating environment, including changes in or interpretation of tax law and currency/repatriation controls, could impact the determination of our income tax liabilities for a tax year.

We are subject to foreign exchange risks and limitations on our ability to reinvest earnings from operations in one country to fund the capital needs of our operations in other countries or to repatriate assets from some countries.

A sizable portion of our consolidated revenue and consolidated operating expenses is in foreign currencies. As a result, we are subject to significant risks, including:

- foreign currency exchange risks resulting from changes in foreign currency exchange rates and the implementation of exchange controls; and
- limitations on our ability to reinvest earnings from operations in one country to fund the capital needs of our operations in other countries.

As an example, we conduct business in countries, such as Venezuela, that have nontraded or “soft” currencies that, because of their restricted or limited trading markets, may be more difficult to exchange for “hard” currency. We may accumulate cash in soft currencies, and we may be limited in our ability to convert our profits into United States dollars or to repatriate the profits from those countries.

Trends in oil and natural gas prices affect the level of exploration, development, and production activity of our customers and the demand for our services and products which could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Demand for our services and products 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. The level of exploration, development, and production activity is directly affected by trends in oil and natural gas prices, which, historically, have been volatile and are likely to continue to be volatile.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of other economic factors that are beyond our control. Any prolonged reduction in oil and natural gas prices will depress the immediate levels of exploration, development, and production activity which could have a material adverse effect on our consolidated results of operations and consolidated financial condition. Even the perception of longer-term lower oil and natural gas prices by oil and natural gas companies can similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Factors affecting the prices of oil and natural gas include:

- the level of supply and demand for oil and natural gas, especially demand for natural gas in the United States;
- governmental regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- weather conditions and natural disasters;
- worldwide political, military, and economic conditions;
- the level of oil production by non-OPEC countries and the available excess production capacity within OPEC;
- oil refining capacity and shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- the cost of producing and delivering oil and natural gas; and
- potential acceleration of development of alternative fuels.

Our business is dependent on capital spending by our customers and reductions in capital spending could have a material adverse effect on our consolidated results of operations.

Our business is directly affected by changes in capital expenditures by our customers, and restrictions in capital spending could have a material adverse effect on our consolidated results of operations. Some of the changes that may materially and adversely affect us include:

- the consolidation of our customers, which could:
  - cause customers to reduce their capital spending, which would in turn reduce the demand for our services and products; and
  - result in customer personnel changes, which in turn affect the timing of contract negotiations; and
- adverse developments in the business and operations of our customers in the oil and natural gas industry, including write-downs of reserves and reductions in capital spending for exploration, development, and production.

If our customers delay paying or fail to pay a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We depend on a limited number of significant customers. While none of these customers represented more than 10% of consolidated revenue in any period presented, the loss of one or more significant customers could have a material adverse effect on our business and our consolidated results of operations.

In most cases, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. If our customers delay paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Our business in Venezuela subjects us to actions by the Venezuelan government and delays in receiving payments, which could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We believe there are risks associated with our operations in Venezuela, including the possibility that the Venezuelan government could assume control over our operations and assets. We also continue to see a delay in receiving payment on our receivables from our primary customer in Venezuela. If our customer further delays paying or fails to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

The future results of our Venezuelan operations will be affected by many factors, including our ability to take actions to mitigate the effect of a devaluation of the Bolívar Fuerte, the foreign currency exchange rate, actions of the Venezuelan government, and general economic conditions such as continued inflation and future customer payments and spending.

The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or limiting or banning, the hydraulic fracturing process could make it more difficult to complete natural gas and oil wells and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We are a leading provider of hydraulic fracturing services. Bills have been introduced in Congress based on assertions that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require federal regulation of hydraulic fracturing operations and the reporting and public disclosure of chemicals used in the fracturing process. This legislation, if adopted, could establish additional levels of regulation at the federal level that could lead to operational delays and increased operating costs. At the same time, legislation and/or regulations have been adopted in several states that requires additional disclosure regarding chemicals used in the fracturing process but that includes protections for proprietary information. Legislation and/or regulations are being considered in other states that could impose further chemical disclosure or other regulatory requirements (such as restrictions on the use of certain types of chemicals or prohibitions on hydraulic fracturing operations in certain areas) that could affect our operations. In addition, governmental authorities in various foreign countries where we have provided or may provide hydraulic fracturing services have imposed or are considering imposing various restrictions or conditions that may affect hydraulic fracturing operations.

We are one of several unrelated companies who received a subpoena from the Office of the New York Attorney General, dated June 17, 2011. The subpoena sought information and documents relating to, among other things, natural gas development and hydraulic fracturing. After discussing the requests in the subpoena with the New York Attorney General’s office, we responded to certain requests and supplied certain records and information as appropriate.

The adoption of any future federal, state, or foreign laws or implementing regulations imposing reporting obligations on, or limiting or banning, the hydraulic fracturing process could make it more difficult to complete natural gas and oil wells and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition. For further information, see Part I, Item 1 “Business.”

Liability for cleanup costs, natural resource damages, and other damages arising as a result of environmental laws could be substantial and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We are exposed to claims under environmental requirements and, from time to time, such claims have been made against us. In the United States, environmental requirements and regulations typically impose strict liability. Strict liability means that in some situations we could be exposed to liability for cleanup costs, natural resource damages, and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of prior operators or other third parties. Liability for damages arising as a result of environmental laws could be substantial and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We are periodically notified of potential liabilities at federal and state superfund sites. These potential liabilities may arise from both historical Halliburton operations and the historical operations of companies that we have acquired. Our exposure at these sites may be materially impacted by unforeseen adverse developments both in the final remediation costs and with respect to the final allocation among the various parties involved at the sites. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. The relevant regulatory agency may bring suit against us for amounts in excess of what we have accrued and what we believe is our proportionate share of remediation costs at any superfund site. We also could be subject to third-party claims, including punitive damages, with respect to environmental matters for which we have been named as a potentially responsible party.

Constraints in the supply of, prices for, and availability of transportation of raw materials can have a material adverse effect on our consolidated results of operations.

Raw materials essential to our business are normally readily available. High levels of demand for raw materials, such as gels, proppants, and hydrochloric acid, can trigger constraints in the supply chain of those raw materials, particularly where we have a relationship with a single supplier for a particular resource. Many of the raw materials essential to our business require the use of rail, storage, and trucking services to transport the materials to our jobsites. These services, particularly during times of high demand, may cause delays in the arrival of or otherwise constrain our supply of raw materials. These constraints could have a material adverse effect on our business and consolidated results of operations. In addition, price increases imposed by our vendors for raw materials used in our business and the inability to pass these increases through to our customers could have a material adverse effect on our business and consolidated results of operations.

Doing business with national oil companies exposes us to greater risks of cost overruns, delays, and project losses and unsettled political conditions that can heighten these risks.

Much of the world's oil and natural gas reserves are controlled by national or state-owned oil companies (NOCs). Several of the NOCs are among our top 20 customers. Increasingly, NOCs are turning to oilfield services companies like us to provide the services, technologies, and expertise needed to develop their reserves. Reserve estimation is a subjective process that involves estimating location and volumes based on a variety of assumptions and variables that cannot be directly measured. As such, the NOCs may provide us with inaccurate information in relation to their reserves that may result in cost overruns, delays, and project losses. In addition, NOCs often operate in countries with unsettled political conditions, war, civil unrest, or other types of community issues. These types of issues may also result in similar cost overruns, delay, and project losses.

A downward trend in estimates of production volumes or commodity prices or an upward trend in production costs could have a material adverse effect on our consolidated results of operations and result in impairment of or higher depletion rate on our oil and natural gas properties.

We have interests in oil and natural gas properties primarily in North America totaling approximately $180 million, net of accumulated depletion, which we account for under the successful efforts method. These oil and natural gas properties are assessed for impairment whenever changes in facts and circumstances indicate that the properties' carrying amounts may not be recoverable. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review.

A downward trend in estimates of production volumes or prices or an upward trend in production costs could have a material adverse effect on our consolidated results of operations and result in other impairment charges or a higher depletion rate on our oil and natural gas properties.

Some of our customers require us to enter into long-term, fixed-price contracts that may require us to assume additional risks associated with cost over-runs, operating cost inflation, labor availability and productivity, supplier and contractor pricing and performance, and potential claims for liquidated damages.

Our customers, primarily NOCs, may require integrated, long-term, fixed-price contracts that could require us to provide integrated project management services outside our normal discrete business to act as project managers as well as service providers. Providing services on an integrated basis may require us to assume additional risks associated with cost over-runs, operating cost inflation, labor availability and productivity, supplier and contractor pricing and performance, and potential claims for liquidated damages. For example, we generally rely on third-party subcontractors and equipment providers to assist us with the completion of our contracts. To the extent that we cannot engage subcontractors or acquire equipment or materials, our ability to complete a project in a timely fashion or at a profit may be impaired. If the amount we are required to pay for these goods and services exceeds the amount we have estimated in bidding for fixed-price work, we could experience losses in the performance of these contracts. These delays and additional costs may be substantial, and we may be required to compensate our customers for these delays. This may reduce the profit to be realized or result in a loss on a project.

Our acquisitions, dispositions, and investments may not result in the realization of savings, the creation of efficiencies, the generation of cash or income, or the reduction of risk, which may have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We continually seek opportunities to maximize efficiency and value through various transactions, including purchases or sales of assets, businesses, investments, or joint ventures. These transactions are intended to result in the realization of savings, the creation of efficiencies, the offering of new products or services, the generation of cash or income, or the reduction of risk. Acquisition transactions may be financed by additional borrowings or by the issuance of our common stock. These transactions may also affect our liquidity, consolidated results of operations, and consolidated financial condition.

These transactions also involve risks, and we cannot ensure that:

- any acquisitions would result in an increase in income;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence prior to an acquisition would uncover situations that could result in financial or legal exposure, including under the FCPA, or that we will appropriately quantify the exposure from known risks;
- any disposition would not result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions would not adversely affect our cash available for capital expenditures and other uses;
- any dispositions, investments, acquisitions, or integrations would not divert management resources; or
- any dispositions, investments, acquisitions, or integrations would not have a material adverse effect on our liquidity, consolidated results of operations, or consolidated financial condition.

Actions of and disputes with our joint venture partners could have a material adverse effect on the business and results of operations of our joint ventures and, in turn, our business and consolidated results of operations.

We conduct some operations through joint ventures, where control may be shared with unaffiliated third parties. As with any joint venture arrangement, differences in views among the joint venture participants may result in delayed decisions or in failures to agree on major issues. We also cannot control the actions of our joint venture partners, including any nonperformance, default, or bankruptcy of our joint venture partners. These factors could have a material adverse effect on the business and results of operations of our joint ventures and, in turn, our business and consolidated results of operations.

Failure on our part to comply with applicable environmental requirements could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Our business is subject to a variety of environmental laws, rules, and regulations in the United States and other countries, including those covering hazardous materials and requiring emission performance standards for facilities. For example, our well service operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. We also store, transport, and use radioactive and explosive materials in certain of our operations. Environmental requirements include, for example, those concerning:

- the containment and disposal of hazardous substances, oilfield waste, and other waste materials;
- the importation and use of radioactive materials;
- the use of underground storage tanks; and
- the use of underground injection wells.

Environmental and other similar requirements generally are becoming increasingly strict. Sanctions for failure to comply with these requirements, many of which may be applied retroactively, may include:

- administrative, civil, and criminal penalties;
- revocation of permits to conduct business; and
- corrective action orders, including orders to investigate and/or clean up contamination.

Failure on our part to comply with applicable environmental requirements could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition. We are also exposed to costs arising from environmental compliance, including compliance with changes in or expansion of environmental requirements, which could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change could have a negative impact on our business and may result in additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Changes in environmental requirements related to greenhouse gases and climate change may negatively impact demand for our services. For example, oil and natural gas exploration and production may decline as a result of environmental requirements (including land use policies responsive to environmental concerns). State, national, and international governments and agencies have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of greenhouse gases in areas in which we conduct business. Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to greenhouse gases 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 natural gas. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture, sequestration, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Changes in, compliance with, or our failure to comply with laws in the countries in which we conduct business may negatively impact our ability to provide services in, make sales of equipment to, and transfer personnel or equipment among, some of those countries and could have a material adverse affect on our consolidated results of operations.

In the countries in which we conduct business, we are subject to multiple and, at times, inconsistent regulatory regimes, including those that govern our use of radioactive materials, explosives, and chemicals in the course of our operations. Various national and international regulatory regimes govern the shipment of these items. Many countries, but not all, impose special controls upon the export and import of radioactive materials, explosives, and chemicals. Our ability to do business is subject to maintaining required licenses and complying with these multiple regulatory requirements applicable to these special products. In addition, the various laws governing import and export of both products and technology apply to a wide range of services and products we offer. In turn, this can affect our employment practices of hiring people of different nationalities because these laws may prohibit or limit access to some products or technology by employees of various nationalities. Changes in, compliance with, or our failure to comply with these laws may negatively impact our ability to provide services in, make sales of equipment to, and transfer personnel or equipment among some of the countries in which we operate and could have a material adverse effect on our business and consolidated results of operations.

Our failure to protect our proprietary information and any successful intellectual property challenges or infringement proceedings against us could materially and adversely affect our competitive position.

We rely on a variety of intellectual property rights that we use in our services and products. We may not be able to successfully preserve these intellectual property rights in the future, and these rights could be invalidated, circumvented, or challenged. In addition, the laws of some foreign countries in which our services and products may be sold do not protect intellectual property rights to the same extent as the laws of the United States. Our failure to protect our proprietary information and any successful intellectual property challenges or infringement proceedings against us could materially and adversely affect our competitive position.

If we are not able to design, develop, and produce commercially competitive products and to implement commercially competitive services in a timely manner in response to changes in technology, our business and consolidated results of operations could be materially and adversely affected, and the value of our intellectual property may be reduced.

The market for our services and products is characterized by continual technological developments to provide better and more reliable performance and services. If we are not able to design, develop, and produce commercially competitive products and to implement commercially competitive services in a timely manner in response to changes in technology, our business and revenue could be materially and adversely affected, and the value of our intellectual property may be reduced. Likewise, if our proprietary technologies, equipment and facilities, or work processes become obsolete, we may no longer be competitive, and our business and consolidated results of operations could be materially and adversely affected.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

Our ability to operate and our growth potential could be materially and adversely affected if we cannot employ and retain technical personnel at a competitive cost.

Many of the services that we provide and the products that we sell are complex and highly engineered and often must perform or be performed in harsh conditions. We believe that our success depends upon our ability to employ and retain technical personnel with the ability to design, utilize, and enhance these services and products. In addition, our ability to expand our operations depends in part on our ability to increase our skilled labor force. A significant increase in the wages paid by competing employers could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our cost structure could increase, our margins could decrease, and any growth potential could be impaired.

Our business could be materially and adversely affected by severe or unseasonable weather where we have operations.

Our business could be materially and adversely affected by severe weather, particularly in the Gulf of Mexico, Russia, and the North Sea where we have operations. Some experts believe global climate change could increase the frequency and severity of these extreme weather conditions. Repercussions of severe weather conditions may include:

- evacuation of personnel and curtailment of services;
- weather-related damage to offshore drilling rigs resulting in suspension of operations;
- weather-related damage to our facilities and project work sites;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of productivity.

Because demand for natural gas in the United States drives a significant amount of our business, warmer than normal winters in the United States are detrimental to the demand for our services to natural gas producers.

Item 1(b). Unresolved Staff Comments.

None.

Item 2. Properties.

We own or lease numerous properties in domestic and foreign locations. The following locations represent our major facilities and corporate offices.

Location	Owned/Leased	Description
Completion and Production segment:		
Arbroath, United Kingdom	Owned	Manufacturing facility
Johor, Malaysia	Leased	Manufacturing facility
Monterrey, Mexico	Leased	Manufacturing facility
Sao Jose dos Campos, Brazil	Leased	Manufacturing facility
Stavanger, Norway	Leased	Research and development laboratory
Drilling and Evaluation segment:		
Alvarado, Texas	Owned	Manufacturing facility
Nisku, Canada	Owned	Manufacturing facility
Singapore	Leased	Manufacturing and technology facility
The Woodlands, Texas	Leased	Manufacturing facility
Shared/corporate facilities:		
Carrollton, Texas	Owned	Manufacturing facility
Dubai, United Arab Emirates	Leased	Corporate executive offices and shared services
Duncan, Oklahoma	Owned	Manufacturing, technology, shared services, and campus facilities
Houston, Texas	Owned/Leased	Corporate executive offices, manufacturing, technology, and campus facilities
Pune, India	Leased	Technology facility

All of our owned properties are unencumbered.

In addition, we have 192 international and 111 United States field camps from which we deliver our services and products. We also have numerous small facilities that include sales, project, and support offices and bulk storage facilities throughout the world.

We believe all properties that we currently occupy are suitable for their intended use.

Item 3. Legal Proceedings.

The Gulf of Mexico/Macondo well incident

Overview. The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for the lease operator, BP Exploration & Production, Inc. (BP Exploration), an indirect wholly owned subsidiary of BP p.l.c. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. Crude oil flowing from the well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. Numerous attempts at estimating the volume of oil spilled have been made by various groups, and on August 2, 2010 the federal government published an estimate that approximately 4.9 million barrels of oil were discharged from the well. Efforts to contain the flow of hydrocarbons from the well were led by the United States government and by BP p.l.c., BP Exploration, and their affiliates (collectively, BP). The flow of hydrocarbons from the well ceased on July 15, 2010, and the well was permanently capped on September 19, 2010. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

We are currently unable to estimate the impact the Macondo well incident will have on us. The multi-district litigation (MDL) trial referred to below is scheduled to begin in late February 2012, and recently there have been and we expect there will continue to be orders and rulings of the court that impact the MDL. Moreover, as discussed below, BP has in the last nine months settled litigation with several other defendants in the MDL. We cannot predict the outcome of the many lawsuits and investigations relating to the Macondo well incident, including whether the MDL will proceed to trial, the results of any such trial, or whether we might settle with one or more of the parties to any lawsuit or investigation. Given the numerous potential future developments relating to the MDL and other lawsuits and investigations, we are unable to conclude whether we will incur a loss. As of December 31, 2011, we have not accrued any amounts related to this matter because we have not determined that a loss is probable and a reasonable estimate of a loss or range of loss related to this matter cannot be made. As a result of any future developments, some of which could occur as soon as within the next few months, we may adjust our liability assessment, and liabilities arising out of this matter could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Investigations and Regulatory Action. The United States Coast Guard, a component of the United States Department of Homeland Security, and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly known as the Minerals Management Service (MMS) and which was replaced effective October 1, 2011 by two new, independent bureaus – the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM)), a bureau of the United States Department of the Interior, shared jurisdiction over the investigation into the Macondo well incident and formed a joint investigation team that reviewed information and held hearings regarding the incident (Marine Board Investigation). We were named as one of the 16 parties-in-interest in the Marine Board Investigation. The Marine Board Investigation, as well as investigations of the incident that were conducted by The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) and the National Academy of Sciences, have been completed, and reports issued as a result of those investigations are discussed below. In addition, the Chemical Safety Board is conducting an investigation to examine the root causes of the accidental release of hydrocarbons from the Macondo well, including an examination of key technical factors, the safety cultures involved, and the effectiveness of relevant laws, regulations, and industry standards.

In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. The suspension was lifted in October 2010. Later, the Department of the Interior issued new guidance and regulations for drillers that intend to resume deepwater drilling activity and has proposed additional regulations. Despite the fact that the drilling suspension was lifted, the BOEMRE did not issue permits for the resumption of drilling for an extended period of time, and we experienced a significant reduction in our Gulf of Mexico operations. In the first quarter of 2011, the BOEMRE resumed the issuance of drilling permits, and activity has gradually recovered since that time, although there can be no assurance of future activity levels in the Gulf of Mexico. For additional information, see Part II, Item 1(a), "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations."

DOJ Investigations and Actions. On June 1, 2010, the United States Attorney General announced that the Department of Justice (DOJ) was launching civil and criminal investigations into the Macondo well incident to closely examine the actions of those involved, and that the DOJ was working with attorneys general of states affected by the Macondo well incident. The DOJ announced that it was reviewing, among other traditional criminal statutes, possible violations of and liabilities under The Clean Water Act (CWA), The Oil Pollution Act of 1990 (OPA), The Migratory Bird Treaty Act of 1918 (MBTA), and the Endangered Species Act of 1973 (ESA). As part of its criminal investigation, the DOJ is examining certain aspects of our conduct after the incident, including with respect to record-keeping, record retention, post-incident testing, securities filings, and public statements by us or our employees, to evaluate whether there has been any violation of federal law.

The CWA provides authority for civil and criminal penalties for discharges of oil into or upon navigable waters of the United States, adjoining shorelines, or in connection with the Outer Continental Shelf Lands Act (OCSLA) in quantities that are deemed harmful. A single discharge event may result in the assertion of numerous violations under the CWA. Criminal sanctions under the CWA can be assessed for negligent discharges (up to $50,000 per day per violation), for knowing discharges (up to $100,000 per day per violation), and for knowing endangerment (up to $2 million per violation), and federal agencies could be precluded from contracting with a company that is criminally sanctioned under the CWA. Civil proceedings under the CWA can be commenced against an "owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged" in violation of the CWA. The civil penalties that can be imposed against responsible parties range from up to $1,100 per barrel of oil discharged in the case of those found strictly liable to $4,300 per barrel of oil discharged in the case of those found to have been grossly negligent.

The OPA establishes liability for discharges of oil from vessels, onshore facilities, and offshore facilities into or upon the navigable waters of the United States. Under the OPA, the "responsible party" for the discharging vessel or facility is liable for removal and response costs as well as for damages, including recovery costs to contain and remove discharged oil and damages for injury to natural resources and real or personal property, lost revenues, lost profits, and lost earning capacity. The cap on liability under the OPA is the full cost of removal of the discharged oil plus up to $75 million for damages, except that the $75 million cap does not apply in the event the damage was proximately caused by gross negligence or the violation of certain federal safety, construction or operating standards. The OPA defines the set of responsible parties differently depending on whether the source of the discharge is a vessel or an offshore facility. Liability for vessels is imposed on owners and operators; liability for offshore facilities is imposed on the holder of the permit or lessee of the area in which the facility is located.

The MBTA and the ESA provide penalties for injury and death to wildlife and bird species. The MBTA provides that violators are strictly liable and such violations are misdemeanor crimes subject to fines of up to $15,000 per bird killed and imprisonment of up to six months. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation and, in the case of criminal penalties, up to $50,000 per violation.

In addition, federal law provides for a variety of fines and penalties, the most significant of which is the Alternative Fines Act. In lieu of the express amount of the criminal fines that may be imposed under some of the statutes described above, the Alternative Fines Act provides for a fine in the amount of twice the gross economic loss suffered by third parties, which amount, although difficult to estimate, is significant.

On December 15, 2010, the DOJ filed a civil action seeking damages and injunctive relief against BP Exploration, Anadarko Petroleum Corporation and Anadarko E&P Company LP (together, Anadarko), who had an approximate 25% interest in the Macondo well, certain subsidiaries of Transocean Ltd., and others for violations of the CWA and the OPA. The DOJ's complaint seeks an action declaring that the defendants are strictly liable under the CWA as a result of harmful discharges of oil into the Gulf of Mexico and upon United States shorelines as a result of the Macondo well incident. The complaint also seeks an action declaring that the defendants are strictly liable under the OPA for the discharge of oil that has resulted in, among other things, injury to, loss of, loss of use of, or destruction of natural resources and resource services in and around the Gulf of Mexico and the adjoining United States shorelines and resulting in removal costs and damages to the United States far exceeding $75 million. BP Exploration has been designated, and has accepted the designation, as a responsible party for the pollution under the CWA and the OPA. Others have also been named as responsible parties, and all responsible parties may be held jointly and severally liable for any damages under the OPA. A responsible party may make a claim for contribution against any other responsible party or against third parties it alleges contributed to or caused the oil spill. In connection with the proceedings discussed below under "Litigation," in April 2011 BP Exploration filed a claim against us for contribution with respect to liabilities incurred by BP Exploration under the OPA or another law and requested a judgment that the DOJ assert its claims for OPA financial liability directly against us.

We have not been named as a responsible party under the CWA or the OPA in the DOJ civil action, and we do not believe we are a responsible party under the CWA or the OPA. While we are not included in the DOJ's civil complaint, there can be no assurance that the DOJ or other federal or state governmental authorities will not bring an action, whether civil or criminal, against us under the CWA, the OPA, and/or other statutes or regulations. In connection with the DOJ's filing of the civil action, it announced that its criminal and civil investigations are continuing and that it will employ efforts to hold accountable those who are responsible for the incident.

A federal grand jury has been convened in Louisiana to investigate potential criminal conduct in connection with the Macondo well incident. We are cooperating fully with the DOJ's criminal investigation. As of February 16, 2012, the DOJ has not commenced any criminal proceedings against us. We cannot predict the status or outcome of the DOJ's criminal investigation or estimate the potential impact the investigation may have on us or our liability assessment, all of which may change as the investigation progresses.

In June 2010, we received a letter from the DOJ requesting thirty days advance notice of any event that may involve substantial transfers of cash or other corporate assets outside of the ordinary course of business. We conveyed our interest in briefing the DOJ on the services we provided on the Deepwater Horizon but indicated that we would not bind ourselves to the DOJ request.

We have had and expect to continue to have discussions with the DOJ regarding the Macondo well incident and associated pre-incident and post-incident conduct.

Investigative Reports. On September 8, 2010, an incident investigation team assembled by BP issued the Deepwater Horizon Accident Investigation Report (BP Report). The BP Report outlined eight key findings of BP related to the possible causes of the Macondo well incident, including failures of cement barriers, failures of equipment provided by other service companies and the drilling contractor, and failures of judgment by BP and the drilling contractor. With respect to the BP Report's assessment that the cement barrier did not prevent hydrocarbons from entering the wellbore after cement placement, the BP Report concluded that, among other things, there were "weaknesses in cement design and testing." According to the BP Report, the BP incident investigation team did not review its analyses or conclusions with us or any other entity or governmental agency conducting a separate or independent investigation of the incident. In addition, the BP incident investigation team did not conduct any testing using our cementing products.

On June 22, 2011, Transocean released its internal investigation report on the causes of the Macondo well incident. Transocean's report, among other things, alleges deficiencies with our cementing services on the Deepwater Horizon. Like the BP Report, the Transocean incident investigation team did not review its analyses or conclusions with us and did not conduct any testing using our cementing products.

On January 11, 2011, the National Commission released "Deep Water -- The Gulf Oil Disaster and the Future of Offshore Drilling," its investigation report (Investigation Report) to the President of the United States regarding, among other things, the National Commission's conclusions of the causes of the Macondo well incident. According to the Investigation Report, the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report stated that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report, however, acknowledges a fact widely accepted by the industry that cementing wells is a complex endeavor utilizing an inherently uncertain process in which failures are not uncommon and that, as a result, the industry utilizes the negative-pressure test and cement bond log test, among others, to identify cementing failures that require remediation before further work on a well is performed.

The Investigation Report also sets forth the National Commission's findings on certain missteps, oversights and other factors that may have caused, or contributed to the cause of, the incident, including BP's decision to use a long string casing instead of a liner casing, BP's decision to use only six centralizers, BP's failure to run a cement bond log, BP's reliance on the primary cement job as a barrier to a possible blowout, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, BP's temporary abandonment procedures, and the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, gas, or fluid into the well (known as a "kick") was occurring. With respect to the National Commission's finding that our surface data logging specialist failed to recognize a kick, the Investigation Report acknowledged that there were simultaneous activities and other monitoring responsibilities that may have prevented the surface data logging specialist from recognizing a kick.

The Investigation Report also identified two general root causes of the Macondo well incident: systemic failures by industry management, which the National Commission labeled "the most significant failure at Macondo," and failures in governmental and regulatory oversight. The National Commission cited examples of failures by industry management such as BP's lack of controls to adequately identify or address risks arising from changes to well design and procedures, the failure of BP's and our processes for cement testing, communication failures among BP, Transocean, and us, including with respect to the difficulty of our cement job, Transocean's failure to adequately communicate lessons from a recent near-blowout, and the lack of processes to adequately assess the risk of decisions in relation to the time and cost those decisions would save. With respect to failures of governmental and regulatory oversight, the National Commission concluded that applicable drilling regulations were inadequate, in part because of a lack of resources and political support of the MMS, and a lack of expertise and training of MMS personnel to enforce regulations that were in effect.

As a result of the factual and technical complexity of the Macondo well incident, the Chief Counsel of the National Commission issued a separate, more detailed report regarding the technical, managerial, and regulatory causes of the Macondo well incident in February 2011.

In March 2011, a third party retained by the BOEMRE to undertake a forensic examination and evaluation of the blowout preventer stack, its components and associated equipment, released a report detailing its findings. The forensic examination report found, among other things, that the blowout preventer stack failed primarily because the blind sheer rams did not fully close and seal the well due to a portion of drill pipe that had become trapped between the blocks and the pipe being outside the cutting surface of the ram blades. The forensic examination report recommended further examination, investigation, and testing, which found that the redundant operating pods of the blowout preventer may not have timely functioned the blind shear rams in the automatic mode function due to a depleted battery in one pod and a miswired solenoid in the other pod. We had no part in manufacturing or servicing the blowout preventer stack.

In September 2011, the BOEMRE released the final report of the Marine Board Investigation regarding the Macondo well incident (BOEMRE Report). A panel of investigators of the BOEMRE identified a number of causes of the Macondo well incident. According to the BOEMRE Report, "a central cause of the blowout was failure of a cement barrier in the production casing string." The panel was unable to identify the precise reasons for the failure but concluded that it was likely due to: "(1) swapping of cement and drilling mud in the shoe track (the section of casing near the bottom of the well); (2) contamination of the shoe track cement; or (3) pumping the cement past the target location in the well, leaving the shoe track with little or no cement." Generally, the panel concluded that the Macondo well incident was the result of, among other things, poor risk management, last-minute changes to drilling plans, failure to observe and respond to critical indicators, and inadequate well control response by the companies and individuals involved. In particular, the BOEMRE Report stated that BP made a series of decisions that complicated the cement job and may have contributed to the failure of the cement job, including the use of only one cement barrier, the location of the production casing, and the failure to follow industry-accepted recommendations.

The BOEMRE Report also stated, among other things, that BP failed to properly communicate well design and cementing decisions and risks to Transocean, that BP and Transocean failed to correctly interpret the negative-pressure test, and that we, BP, and Transocean failed to detect the influx of hydrocarbons into the well. According to the BOEMRE Report, the panel found evidence that we, among others, violated federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the well under control, and the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico. In October 2011, the BSEE issued a notification of INCs to us for violating those regulations and a federal regulation relating to the failure to protect health, safety, property, and the environment as a result of a failure to perform operations in a safe and workmanlike manner. According to the BSEE's notice, we did not ensure an adequate barrier to hydrocarbon flow after cementing the production casing and did not detect the influx of hydrocarbons until they were above the blowout preventer stack. We understand that the regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation. We have appealed the INCs to, and the appeal was accepted by, the Interior Board of Land Appeals (IBLA). In January 2012, the IBLA, in response to our and the BSEE's joint request, has suspended the appeal and has ordered us and the BSEE to file notice within 15 days after the conclusion of the MDL and, within 60 days after the MDL court issues a final decision, to file a proposal for further action in the appeal. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal has ended. The BSEE has stated that this is the first time the Department of the Interior has issued INCs directly to a contractor that was not the well's operator. We have not accrued any amounts related to the INCs.

In December 2011, the National Academy of Sciences released a pre-publication copy of its report examining the causes of the Macondo well incident and identifying measures for preventing similar incidents in the future (NAS Report). The NAS Report noted that it does not attempt to assign responsibility to specific individuals or entities or determine the extent that the parties involved complied with applicable regulations.

According to the NAS Report, the flow of hydrocarbons that led to the blowout began when drilling mud was displaced by seawater during the temporary abandonment process, which was commenced by the drilling team despite a failure to demonstrate the integrity of the cement job after multiple negative pressure tests and after incorrectly deciding that a negative pressure test indicated that the cement barriers were effective. In addition, the NAS Report found, among other things, that: the approach chosen for well completion failed to provide adequate safety margins considering the reservoir formation; the loss of well control was not noted until more than 50 minutes after hydrocarbon flow from the formation had started; the blowout preventer was not designed or tested for the dynamic conditions that most likely existed at the time attempts were made to recapture well control; and the entities involved did not provide an effective systems safety approach commensurate with the risks of the Macondo well. According to the NAS Report, a number of key decisions related to the design, construction, and testing of the barriers critical to the temporary abandonment process were flawed.

The NAS Report also found, among other things, that the heavier "tail" cement slurry, intended for placement in the Macondo well shoe track, was "gravitationally unstable" on top of the lighter foam cement slurry and that the heavier tail cement slurry probably fell into or perhaps through the lighter foam cement slurry during pumping into the well, which would have left a tail slurry containing foam cement in the shoe track. The NAS Report also found, among other things, that foam cement that may have been inadvertently left in the shoe track likely would not have had the strength to resist crushing when experiencing the differential pressures exerted on the cement during the negative pressure test. In addition, the NAS Report found, among other things, that evidence available before the blowout indicated that the flapper valves in the float collar probably failed to seal, but the evidence was not acted upon and, due to BP's choice of a long-string production casing and the lack of minimum circulation of the well prior to the cement job, the possibility of mud-filled channels or poor cement bonding existed.

The NAS Report also set forth the following observations, among others: (1) there were alternative completion techniques and operational processes available that could have safely prepared the well for temporary abandonment; (2) post-incident static tests on a foam cement slurry similar to the slurry pumped into the Macondo well were performed under laboratory conditions and exhibited the settling of cement and nitrogen breakout, although because the tests were not conducted at bottom hole conditions "it is impossible to say whether the foam was stable at the bottom of the well"; (3) the "cap" cement slurry was subject to contamination by the spacer or the drilling mud that was placed ahead of the cap cement slurry and, if the cap cement slurry was heavily contaminated, it would not reach the strength of uncontaminated cement; (4) the numerous companies involved and the division of technical expertise among those companies affected their ability to perform and maintain an integrated assessment of the margins of safety for the Macondo well; (5) the regulatory regime was ineffective in addressing the risks of the Macondo well; and (6) training of key personnel and decision makers in the industry and regulatory agencies has been inadequate relative to the risks and complexities of deepwater drilling.

The NAS Report recommended, among other things: that all primary cemented barriers to flow should be tested to verify quality, quantity, and location of cement; that the integrity of mechanical barriers should be verified by using the best available test procedures; that blowout preventer systems should be redesigned for the drilling environment to which they are being applied; and that operating companies should have ultimate responsibility and accountability for well integrity, well design, well construction, and the suitability of the rig and associated safety equipment.

The Cementing Job and Reaction to Reports. We disagree with the BP Report, the National Commission, Transocean's report, the BOEMRE Report, and the NAS Report regarding many of their findings and characterizations with respect to the cementing and surface data logging services, as applicable, on the Deepwater Horizon. We have provided information to the National Commission, its staff, and representatives of the joint investigation team for the Marine Board Investigation that we believe has been overlooked or selectively omitted from the Investigation Report and the BOEMRE Report, as applicable. We intend to continue to vigorously defend ourselves in any investigation relating to our involvement with the Macondo well that we believe inaccurately evaluates or depicts our services on the Deepwater Horizon.

The cement slurry on the Deepwater Horizon was designed and prepared pursuant to well condition data provided by BP. Regardless of whether alleged weaknesses in cement design and testing are or are not ultimately established, and regardless of whether the cement slurry was utilized in similar applications or was prepared consistent with industry standards, we believe that had BP and Transocean properly interpreted a negative-pressure test, this test would have revealed any problems with the cement. In addition, had BP designed the Macondo well to allow a full cement bond log test or if BP had conducted even a partial cement bond log test, the test likely would have revealed any problems with the cement. BP, however, elected not to conduct any cement bond log tests, and with Transocean misinterpreted the negative-pressure test, both of which could have resulted in remedial action, if appropriate, with respect to the cementing services.

At this time we cannot predict the impact of the Investigation Report, the BOEMRE Report, the NAS Report, or the conclusions of future reports of the Chemical Safety Board, Congressional committees, or any other governmental or private entity. We also cannot predict whether their investigations or any other report or investigation will have an influence on or result in us being named as a party in any action alleging liability or violation of a statute or regulation, whether federal or state and whether criminal or civil.

We intend to continue to cooperate fully with all governmental hearings, investigations, and requests for information relating to the Macondo well incident. We cannot predict the outcome of, or the costs to be incurred in connection with, any of these hearings or investigations, and therefore we cannot predict the potential impact they may have on us.

Litigation. Since April 21, 2010, plaintiffs have been filing lawsuits relating to the Macondo well incident. Generally, those lawsuits allege either (1) damages arising from the oil spill pollution and contamination (*e.g.*, diminution of property value, lost tax revenue, lost business revenue, lost tourist dollars, inability to engage in recreational or commercial activities) or (2) wrongful death or personal injuries. We are named along with other unaffiliated defendants in more than 400 complaints, most of which are alleged class actions, involving pollution damage claims and at least nine personal injury lawsuits involving four decedents and at least 21 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Plaintiffs originally filed the lawsuits described above in federal and state courts throughout the United States, including Alabama, Delaware, Florida, Georgia, Kentucky, Louisiana, Mississippi, South Carolina, Tennessee, Texas, and Virginia. Except for certain lawsuits not yet consolidated (including two lawsuits that are proceeding in Louisiana state court, one lawsuit that is proceeding in Louisiana federal court, two lawsuits that are proceeding in Texas state court, two lawsuits that are proceeding in Florida federal court, and four lawsuits in Florida state court for which we have not been served), the Judicial Panel on Multi-District Litigation ordered all of the lawsuits against us consolidated in the MDL proceeding before Judge Carl Barbier in the United States Eastern District of Louisiana. The pollution complaints generally allege, among other things, negligence and gross negligence, property damages, taking of protected species, and potential economic losses as a result of environmental pollution and generally seek awards of unspecified economic, compensatory, and punitive damages, as well as injunctive relief. Plaintiffs in these pollution cases have brought suit under various legal provisions, including the OPA, the CWA, the MBTA, the ESA, the OCSLA, the Longshoremen and Harbor Workers Compensation Act, general maritime law, state common law, and various state environmental and products liability statutes.

Furthermore, the pollution complaints include suits brought against us by governmental entities, including the State of Alabama, the State of Louisiana, Plaquemines Parish, the City of Greenville, and three Mexican states. Complaints brought against us by ten other parishes in Louisiana were dismissed with prejudice, and the dismissal is being appealed by those parishes. The wrongful death and other personal injury complaints generally allege negligence and gross negligence and seek awards of compensatory damages, including unspecified economic damages and punitive damages. We have retained counsel and are investigating and evaluating the claims, the theories of recovery, damages asserted, and our respective defenses to all of these claims.

Judge Barbier is also presiding over a separate proceeding filed by Transocean under the Limitation of Liability Act (Limitation Action). In the Limitation Action, Transocean seeks to limit its liability for claims arising out of the Macondo well incident to the value of the rig and its freight. Although the Limitation Action is not consolidated in the MDL, to this point the judge is effectively treating the two proceedings as associated cases. On February 18, 2011, Transocean tendered us, along with all other defendants, into the Limitation Action. As a result of the tender, we and all other defendants will be treated as direct defendants to the plaintiffs' claims as if the plaintiffs had sued each of us and the other defendants directly. In the Limitation Action, the judge intends to determine the allocation of liability among all defendants in the hundreds of lawsuits associated with the Macondo well incident, including those in the MDL proceeding that are pending in his court. Specifically, the judge will determine the liability, limitation, exoneration and fault allocation with regard to all of the defendants in a trial, which is scheduled to occur in three phases, that is set to begin in late February 2012. The three phases of this portion of the trial are scheduled to cover the liabilities associated with the blowout itself, the actions relating to the attempts to control the flow of hydrocarbons from the well, and the efforts to contain and clean-up the oil that was discharged from the Macondo well. We do not believe that a single apportionment of liability in the Limitation Action is properly applied, particularly with respect to gross negligence and punitive damages, to the hundreds of lawsuits pending in the MDL proceeding.

Damages for the cases tried in the MDL proceeding, including punitive damages, are expected to be tried following the three-phase portion of the trial described above. Under ordinary MDL procedures, such cases would, unless waived by the respective parties, be tried in the courts from which they were transferred into the MDL. It remains unclear, however, what impact the overlay of the Limitation Action will have on where these matters are tried. Document discovery and depositions among the parties to the MDL are ongoing. It is unclear how the judge will address the DOJ's civil action for alleged violations of the CWA and the OPA.

In April and May 2011, certain defendants in the proceedings described above filed numerous cross claims and third party claims against certain other defendants. BP Exploration and BP America Production Company filed claims against us seeking subrogation and contribution, including with respect to liabilities under the OPA, and direct damages, and alleging negligence, gross negligence, fraudulent conduct, and fraudulent concealment. Transocean filed claims against us seeking indemnification, and subrogation and contribution, including with respect to liabilities under the OPA and for the total loss of the Deepwater Horizon, and alleging comparative fault and breach of warranty of workmanlike performance. Anadarko filed claims against us seeking tort indemnity and contribution, and alleging negligence, gross negligence and willful misconduct, and MOEX Offshore 2007 LLC (MOEX), who has an approximate 10% interest in the Macondo well, filed a claim against us alleging negligence. Cameron International Corporation (Cameron) (the manufacturer and designer of the blowout preventer), M-I Swaco (provider of drilling fluids and services, among other things), Weatherford U.S. L.P. and Weatherford International, Inc. (together, Weatherford) (providers of casing components, including float equipment and centralizers, and services), and Dril-Quip, Inc. (Dril-Quip) (provider of wellhead systems), each filed claims against us seeking indemnification and contribution, including with respect to liabilities under the OPA in the case of Cameron, and alleging negligence. Additional civil lawsuits may be filed against us. In addition to the claims against us, generally the defendants in the proceedings described above filed claims, including for liabilities under the OPA and other claims similar to those described above, against the other defendants described above. BP has since announced that it has settled those claims between it and each of MOEX, Weatherford, Anadarko, and Cameron.

In April 2011, we filed claims against BP Exploration, BP p.l.c. and BP America Production Company (BP Defendants), M-I Swaco, Cameron, Anadarko, MOEX, Weatherford, Dril-Quip, and numerous entities involved in the post-blowout remediation and response efforts, in each case seeking contribution and indemnification and alleging negligence. Our claims also alleged gross negligence and willful misconduct on the part of the BP Defendants, Anadarko, and Weatherford. We also filed claims against M-I Swaco and Weatherford for contractual indemnification, and against Cameron, Weatherford and Dril-Quip for strict products liability, although the court has since issued orders dismissing all claims asserted against Dril-Quip and Weatherford in the MDL. We filed our answer to Transocean's Limitation petition denying Transocean's right to limit its liability, denying all claims and responsibility for the incident, seeking contribution and indemnification, and alleging negligence and gross negligence.

Judge Barbier has issued an order, among others, clarifying certain aspects of law applicable to the lawsuits pending in his court. The court ruled that: (1) general maritime law will apply and therefore dismissed all claims brought under state law causes of action; (2) general maritime law claims may be brought directly against defendants who are non-"responsible parties" under the OPA with the exception of pure economic loss claims by plaintiffs other than commercial fishermen; (3) all claims for damages, including pure economic loss claims, may be brought under the OPA directly against responsible parties; and (4) punitive damage claims can be brought against both non-responsible parties under general maritime law and responsible parties under the OPA. As discussed above, with respect to the ruling that claims for damages may be brought under the OPA against responsible parties, we have not been named as a responsible party under the OPA, but BP Exploration has filed a claim against us for contribution with respect to liabilities incurred by BP Exploration under the OPA.

In September 2011, we filed claims in Harris County, Texas against the BP Defendants seeking damages, including lost profits and exemplary damages, and alleging negligence, grossly negligent misrepresentation, defamation, common law libel, slander, and business disparagement. Our claims allege that the BP Defendants knew or should have known about an additional hydrocarbon zone in the well that the BP Defendants failed to disclose to us prior to our designing the cement program for the Macondo well. The location of the hydrocarbon zones is critical information required prior to performing cementing services and is necessary to achieve desired cement placement. We believe that had BP Defendants disclosed the hydrocarbon zone to us, we would not have proceeded with the cement program unless it was redesigned, which likely would have required a redesign of the production casing. In addition, we believe that the BP Defendants withheld this information from the BP Report and from the various investigations discussed above. In connection with the foregoing, we also moved to amend our claims against the BP Defendants in the MDL proceeding to include fraud. The BP Defendants have denied all of the allegations relating to the additional hydrocarbon zone and filed a motion to prevent us from adding our fraud claim in the MDL. In October 2011, our motion to add the fraud claim against the BP Defendants in the MDL proceeding was denied. The court's ruling does not, however, prevent us from using the underlying evidence in our pending claims against the BP Defendants.

In December 2011, BP filed a motion for sanctions against us alleging, among other things, that we destroyed evidence relating to post-incident testing of the foam cement slurry on the Deepwater Horizon and requesting adverse findings against us. A magistrate judge in the MDL proceeding denied BP's motion. BP appealed that ruling, and Judge Barbier affirmed the magistrate judge's decision.

We intend to vigorously defend any litigation, fines, and/or penalties relating to the Macondo well incident and to vigorously pursue any damages, remedies, or other rights available to us as a result of the Macondo well incident. We have incurred and expect to continue to incur significant legal fees and costs, some of which we expect to be covered by indemnity or insurance, as a result of the numerous investigations and lawsuits relating to the incident.

Macondo derivative case. In February 2011, a shareholder who had previously made a demand on our board of directors with respect to another derivative lawsuit filed a shareholder derivative lawsuit relating to the Macondo well incident. See "Shareholder derivative cases" below.

Indemnification and Insurance. Our contract with BP Exploration relating to the Macondo well generally provides for our indemnification by BP Exploration for certain potential claims and expenses relating to the Macondo well incident, including those resulting from pollution or contamination (other than claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment). Also, under our contract with BP Exploration, we have, among other things, generally agreed to indemnify BP Exploration and other contractors performing work on the well for claims for personal injury of our employees and subcontractors, as well as for damage to our property. In turn, we believe that BP Exploration was obligated to obtain agreement by other contractors performing work on the well to indemnify us for claims for personal injury of their employees or subcontractors, as well as for damages to their property. We have entered into separate indemnity agreements with Transocean and M-I Swaco, under which we have agreed to indemnify those parties for claims for personal injury of our employees and subcontractors and they have agreed to indemnify us for claims for personal injury of their employees and subcontractors.

In April 2011, we filed a lawsuit against BP Exploration in Harris County, Texas to enforce BP Exploration's contractual indemnity and alleging BP Exploration breached certain terms of the contractual indemnity provision. BP Exploration removed that lawsuit to federal court in the Southern District of Texas, Houston Division. We filed a motion to remand the case to Harris County, Texas, and the lawsuit was transferred to the MDL.

BP Exploration, in connection with filing its claims with respect to the MDL proceeding, asked that court to declare that it is not liable to us in contribution, indemnification, or otherwise with respect to liabilities arising from the Macondo well incident. Other defendants in the litigation discussed above have generally denied any obligation to contribute to any liabilities arising from the Macondo well incident.

In January 2012, the court in the MDL proceeding entered an order in response to our and BP's motions for summary judgment regarding certain indemnification matters. The court held that BP is required to indemnify us for third-party compensatory claims, or actual damages, that arise from pollution or contamination that did not originate from our property or equipment located above the surface of the land or water, even if we are found to be grossly negligent. The court did not express an opinion as to whether our conduct amounted to gross negligence, but we do not believe the performance of our services on the Deepwater Horizon constituted gross negligence. The court also held, however, that BP does not owe us indemnity for punitive damages or for civil penalties under the CWA, if any, and that fraud could void the indemnity on public policy grounds, although the court stated that it was mindful that mere failure to perform contractual obligations as promised does not constitute fraud. As discussed above, the DOJ is not seeking civil penalties from us under the CWA. The court in the MDL proceeding deferred ruling on whether our indemnification from BP covers penalties or fines under the OCSLA, whether our alleged breach of our contract with BP Exploration would invalidate the indemnity, and whether we committed an act that materially increased the risk to or prejudiced the rights of BP so as to invalidate the indemnity. We do not believe that we breached our contract with BP Exploration or committed an act that would otherwise invalidate the indemnity. The court's rulings will be subject to appeal at the appropriate time.

In responding to similar motions for summary judgment between Transocean and BP, the court also held that public policy would not bar Transocean's claim for indemnification of compensatory damages, even if Transocean was found to be grossly negligent. The court also held, among other things, that Transocean's contractual right to indemnity does not extend to punitive damages or civil penalties under the CWA.

The rulings in the MDL proceeding regarding the indemnities are based on maritime law and may not bind the determination of similar issues in lawsuits not comprising a part of the MDL proceedings. Accordingly it is possible that different conclusions with respect to indemnities will be reached by other courts.

Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. In addition, certain state laws, if deemed to apply, would not allow for enforcement of indemnification for gross negligence, and may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims.

Financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. BP's public filings indicate that BP has recognized in excess of $40 billion in pre-tax charges, excluding offsets for settlement payments received from certain defendants in the proceedings described above under "Litigation," as a result of the Macondo well incident. BP's public filings also indicate that the amount of, among other things, certain natural resource damages with respect to certain OPA claims, some of which may be included in such charges, cannot be reliably estimated as of the dates of those filings. We consider, however, the likelihood of a BP bankruptcy to be remote.

In addition to the contractual indemnities discussed above, we have a general liability insurance program of $600 million. Our insurance is designed to cover claims by businesses and individuals made against us in the event of property damage, injury or death and, among other things, claims relating to environmental damage, as well as legal fees incurred in defending against those claims. We have received and expect to continue to receive payments from our insurers with respect to covered legal fees incurred in connection with the Macondo well incident. Through January 2012, we have incurred legal fees and related expenses covered by our insurance program of approximately $76 million. To the extent we incur any losses beyond those covered by indemnification, there can be no assurance that our insurance policies will cover all potential claims and expenses relating to the Macondo well incident. In addition, we may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies. Insurance coverage can be the subject of uncertainties and, particularly in the event of large claims, potential disputes with insurance carriers, as well as other potential parties claiming insured status under our insurance policies.

Barracuda-Caratinga arbitration

We provided indemnification in favor of KBR under the master separation agreement for all out-of-pocket cash costs and expenses (except for legal fees and other expenses of the arbitration so long as KBR controls and directs it), or cash settlements or cash arbitration awards, KBR may incur after November 20, 2006 as a result of the replacement of certain subsea flowline bolts installed in connection with the Barracuda-Caratinga project. At Petrobras' direction, KBR replaced certain bolts located on the subsea flowlines that failed through mid-November 2005, and KBR informed us that additional bolts have failed thereafter, which were replaced by Petrobras. These failed bolts were identified by Petrobras when it conducted inspections of the bolts. In March 2006, Petrobras commenced arbitration against KBR claiming $220 million plus interest for the cost of monitoring and replacing the defective bolts and all related costs and expenses of the arbitration, including the cost of attorneys' fees. The arbitration panel held an evidentiary hearing in March 2008 to determine which party was responsible for the designation of the material used for the bolts. On May 13, 2009, the arbitration panel held that KBR and not Petrobras selected the material to be used for the bolts. Accordingly, the arbitration panel held that there is no implied warranty by Petrobras to KBR as to the suitability of the bolt material and that the parties' rights are to be governed by the express terms of their contract. The parties presented evidence and witnesses to the panel in May 2010, and final arguments were presented in August 2010. During the third quarter of 2011, the arbitration panel issued an award against KBR in the amount of $201 million, which is reflected as a liability and a component of loss from discontinued operations in our consolidated financial statements. KBR filed a motion to vacate the arbitration award with the United States District Court for the Southern District of New York.

Securities and related litigation

In June 2002, a class action lawsuit was filed against us in federal court alleging violations of the federal securities laws after the SEC initiated an investigation in connection with our change in accounting for revenue on long-term construction projects and related disclosures. In the weeks that followed, approximately twenty similar class actions were filed against us. Several of those lawsuits also named as defendants several of our present or former officers and directors. The class action cases were later consolidated, and the amended consolidated class action complaint, styled *Richard Moore, et al. v. Halliburton Company, et al.*, was filed and served upon us in April 2003. As a result of a substitution of lead plaintiffs, the case was styled *Archdiocese of Milwaukee Supporting Fund (AMSF) v. Halliburton Company, et al*. AMSF has changed its name to Erica P. John Fund, Inc. (the Fund). We settled with the SEC in the second quarter of 2004.

In June 2003, the lead plaintiffs filed a motion for leave to file a second amended consolidated complaint, which was granted by the court. In addition to restating the original accounting and disclosure claims, the second amended consolidated complaint included claims arising out of our 1998 acquisition of Dresser Industries, Inc., including that we failed to timely disclose the resulting asbestos liability exposure.

In April 2005, the court appointed new co-lead counsel and named the Fund the new lead plaintiff, directing that it file a third consolidated amended complaint and that we file our motion to dismiss. The court held oral arguments on that motion in August 2005. In March 2006, the court entered an order in which it granted the motion to dismiss with respect to claims arising prior to June 1999 and granted the motion with respect to certain other claims while permitting the Fund to re-plead some of those claims to correct deficiencies in its earlier complaint. In April 2006, the Fund filed its fourth amended consolidated complaint. We filed a motion to dismiss those portions of the complaint that had been re-pled. A hearing was held on that motion in July 2006, and in March 2007 the court ordered dismissal of the claims against all individual defendants other than our Chief Executive Officer (CEO). The court ordered that the case proceed against our CEO and us.

In September 2007, the Fund filed a motion for class certification, and our response was filed in November 2007. The district court held a hearing in March 2008, and issued an order November 3, 2008 denying the motion for class certification. The Fund appealed the district court's order to the Fifth Circuit Court of Appeals. The Fifth Circuit affirmed the district court's order denying class certification. On May 13, 2010, the Fund filed a writ of certiorari in the United States Supreme Court. In early January 2011, the Supreme Court granted the writ of certiorari and accepted the appeal. The Court heard oral arguments in April 2011 and issued its decision in June 2011, reversing the Fifth Circuit ruling that the Fund needed to prove loss causation in order to obtain class certification. The Court's ruling was limited to the Fifth Circuit's loss causation requirement, and the case was returned to the Fifth Circuit for further consideration of our other arguments for denying class certification. The Fifth Circuit returned the case to the district court, and in January 2012 the court issued an order certifying the class which we have appealed. The case is at an early stage, and we cannot predict the outcome or consequences thereof. We intend to vigorously defend this case.

Shareholder derivative cases

In May 2009, two shareholder derivative lawsuits involving us and KBR were filed in Harris County, Texas, naming as defendants various current and retired Halliburton directors and officers and current KBR directors. These cases allege that the individual Halliburton defendants violated their fiduciary duties of good faith and loyalty, to our detriment and the detriment of our shareholders, by failing to properly exercise oversight responsibilities and establish adequate internal controls. The District Court consolidated the two cases, and the plaintiffs filed a consolidated petition against only current and former Halliburton directors and officers containing various allegations of wrongdoing including violations of the FCPA, claimed KBR offenses while acting as a government contractor in Iraq, claimed KBR offenses and fraud under United States government contracts, Halliburton activity in Iran, and illegal kickbacks. Subsequently, a shareholder made a demand that the board take remedial action respecting the FCPA claims in the pending lawsuit. Our Board of Directors designated a special committee of independent and disinterested directors to oversee the investigation of the allegations made in the lawsuits and shareholder demand. Upon receipt of its special committee's findings and recommendations, the independent and disinterested members of the Board determined that the shareholder claims were without merit and not otherwise in the best interest of the company to pursue. The Board directed company counsel to report its determinations to the plaintiffs and demanding shareholder.

We have agreed in principle, subject to approval by the court, to settle the lawsuits. Under the terms of the proposed settlement, we have agreed to implement certain changes to our corporate governance policies and agreed to pay the plaintiffs' legal fees.

In February 2011, the same shareholder who had made the demand on our board of directors in connection with one of the derivative lawsuits discussed above filed a shareholder derivative lawsuit in Harris County, Texas naming us as a nominal defendant and certain of our directors and officers as defendants. This case alleges that these defendants, among other things, breached fiduciary duties of good faith and loyalty by failing to properly exercise oversight responsibilities and establish adequate internal controls, including controls and procedures related to cement testing and the communication of test results, as they relate to the Macondo well incident. Our Board of Directors designated a special committee of independent and disinterested directors to oversee the investigation of the allegations made in the lawsuit and shareholder demand. Upon receipt of its special committee's findings and recommendations, the independent and disinterested members of the Board determined that the shareholder claims were without merit and not otherwise in the best interest of the company to pursue. The Board directed company counsel to report its determinations to the plaintiffs and demanding shareholder.

Angola Investigations

We are conducting an internal investigation of certain areas of our operations in Angola, focusing on compliance with certain company policies, including our Code of Business Conduct (COBC), and the FCPA and other applicable laws. In December 2010, we received an anonymous e-mail alleging that certain current and former personnel violated our COBC and the FCPA, principally through the use of an Angolan vendor. The e-mail also alleges conflicts of interest, self-dealing and the failure to act on alleged violations of our COBC and the FCPA. We contacted the DOJ to advise them that we were initiating an internal investigation with the assistance of outside counsel and independent forensic accountants.

During the third quarter of 2011, we met with the DOJ and the SEC to brief them on the status of our investigation and provided them documents. We are currently responding to a subpoena from the SEC regarding this matter and are producing all relevant documents. We understand that one of our employees has also received a subpoena from the SEC regarding this matter.

We expect to continue to have discussions with the DOJ and the SEC, and we intend to continue to cooperate with their inquiries and requests as they investigate this matter. Because these investigations are at an early stage, we cannot predict their outcome or the consequences thereof.

Environmental

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. In the United States, these laws and regulations include, among others:

- the Comprehensive Environmental Response, Compensation, and Liability Act;
- the Resource Conservation and Recovery Act;
- the Clean Air Act;
- the Federal Water Pollution Control Act;
- the Toxic Substances Control Act; and
- the Oil Pollution Act of 1990.

In addition to the federal laws and regulations, states and other countries where we do business often have numerous environmental, legal, and regulatory requirements by which we must abide. We evaluate and address the environmental impact of our operations by assessing and remediating contaminated properties in order to avoid future liabilities and comply with environmental, legal, and regulatory requirements. Our Health, Safety and Environment group has several programs in place to maintain environmental leadership and to help prevent the occurrence of environmental contamination. On occasion, in addition to the matters relating to the Macondo well incident described above and the Duncan, Oklahoma matter described below, we are involved in other environmental litigation and claims, including the remediation of properties we own or have operated, as well as efforts to meet or correct compliance-related matters. We do not expect costs related to those remediation requirements to have a material adverse effect on our consolidated financial position or our results of operations.

Between 1965 and 1991, a former Halliburton unit known as the Halliburton Industrial Services Division (HISD) performed work for the U.S. Department of Defense cleaning solid fuel from missile casings at a semi-rural facility on the north side of Duncan, Oklahoma. We closed our site in coordination with the Oklahoma Department of Environmental Quality (DEQ) in the mid-1990s, but continued to monitor the groundwater at DEQ's request. A principal component of the missile fuel was ammonium perchlorate, a salt that is highly soluble in water, which has been discovered in the soil and groundwater on our site and in certain residential water wells near our property.

Commencing in October 2011, a number of lawsuits were filed against us, including a putative class action case in federal court in the Western District of Oklahoma and other lawsuits filed in Oklahoma state courts. The lawsuits generally allege, among other things, that operations at our Duncan facility caused releases of pollutants, including ammonium perchlorate and, in the case of the federal lawsuit, nuclear or radioactive waste, into the groundwater, and that we knew about those releases and did not take corrective actions to address them. It is also alleged that the plaintiffs have suffered from certain health conditions, including hypothyroidism, a condition that has been associated with exposure to perchlorate at sufficiently high doses over time. These cases seek, among other things, damages, including punitive damages, and the establishment of a fund for future medical monitoring. The cases allege, among other things, strict liability, trespass, private nuisance, public nuisance, and negligence and, in the case of the federal lawsuit, violations of the U.S. Resource Conservation and Recovery Act, resulting in personal injuries, property damage, and diminution of property value.

The lawsuits generally allege that the cleaning of the missile casings at the Duncan facility contaminated the surrounding soils and groundwater, including certain water wells used in a number of residential homes, through the migration of, among other things, ammonium perchlorate. The federal lawsuit also alleges that our processing of radioactive waste from a nuclear power plant over 25 years ago resulted in the release of "nuclear/radioactive" waste into the environment.

We and the DEQ have recently conducted soil and groundwater sampling relating to the allegations discussed above that has confirmed that the alleged nuclear or radioactive material is confined to the soil in a discrete area of the onsite operations and is not present in the groundwater onsite or in any areas offsite. The radiological impacts from this discrete area are not believed to present any health risk for offsite exposure. With respect to ammonium perchlorate, we have made arrangements to supply affected residents with bottled drinking water and, if needed, with a temporary water supply system, at no cost to the residents. We have worked with the City of Duncan and the DEQ to expedite expansion of the city water supply to the relevant areas.

The lawsuits described above are at an early stage, and additional lawsuits and proceedings may be brought against us. We cannot predict their outcome or the consequences thereof. As of December 31, 2011, we had accrued $35 million related to our initial estimate of response efforts, third-party property damage, and remediation related to the Duncan, Oklahoma matter. We intend to vigorously defend the lawsuits and do not believe that these lawsuits will have a material adverse effect on our liquidity, consolidated results of operations, or consolidated financial condition.

Additionally, we have subsidiaries that have been named as potentially responsible parties along with other third parties for nine federal and state superfund sites for which we have established reserves. As of December 31, 2011, those nine sites accounted for approximately $7 million of our $81 million total environmental reserve. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. Despite attempts to resolve these superfund matters, the relevant regulatory agency may at any time bring suit against us for amounts in excess of the amount accrued. With respect to some superfund sites, we have been named a potentially responsible party by a regulatory agency; however, in each of those cases, we do not believe we have any material liability. We also could be subject to third-party claims with respect to environmental matters for which we have been named as a potentially responsible party.

Item 4. Mine Safety Disclosures.

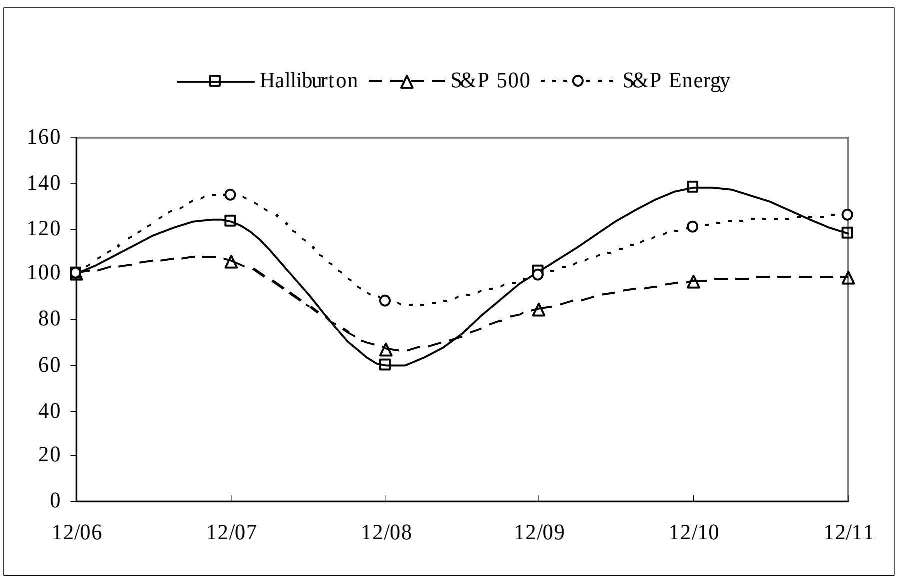
Our barite and bentonite mining operations, in support of our fluid services business, are subject to regulation by the federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act). Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this annual report.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities.

Halliburton Company's common stock is traded on the New York Stock Exchange. Information related to the high and low market prices of our common stock and quarterly dividend payments is included under the caption "Quarterly Data and Market Price Information" on page 118 of this annual report. Cash dividends on our common stock in the amount of $0.09 per share were paid in March, June, September, and December of 2011 and 2010. Our Board of Directors intends to consider the payment of quarterly dividends on the outstanding shares of our common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board of Directors and will depend on, among other things, future earnings, general financial condition and liquidity, success in business activities, capital requirements, and general business conditions.

The following graph and table compare total shareholder return on our common stock for the five-year period ended December 31, 2011, with the Standard & Poor's 500 Stock Index and the Standard & Poor's Energy Composite Index over the same period. This comparison assumes the investment of $100 on December 31, 2006, and the reinvestment of all dividends. The shareholder return set forth is not necessarily indicative of future performance.



	December 31					
	2006	2007	2008	2009	2010	2011
Halliburton	$100.00	$123.33	$59.86	$100.71	$138.27	$117.83
Standard & Poor's 500 Stock Index	100.00	105.49	66.46	84.05	96.71	98.75
Standard & Poor's Energy Composite Index	100.00	134.40	87.54	99.64	120.02	125.69

At February 10, 2012, there were 16,355 shareholders of record. In calculating the number of shareholders, we consider clearing agencies and security position listings as one shareholder for each agency or listing.

The following table is a summary of repurchases of our common stock during the three-month period ended December 31, 2011.

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that may yet be Purchased Under the Program (b)
October 1-31	42,457	$ 33.75	–	$ –
November 1-30	23,243	$ 37.19	–	$ –
December 1-31	118,128	$ 35.15	–	$ –
Total	183,828	$ 35.08	–	$ 1,731,208,803

(a) All of the 183,828 shares purchased during the three-month period ended December 31, 2011 were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting in restricted stock grants. These shares were not part of a publicly announced program to purchase common shares.

(b) Our Board of Directors has authorized a plan to repurchase our common stock from time to time. During the fourth quarter of 2011, we did not repurchase shares of our common stock pursuant to that plan. We have authorization remaining to repurchase up to a total of approximately $1.7 billion of our common stock.

Item 6. Selected Financial Data.

Information related to selected financial data is included on page 117 of this annual report.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Information related to Management's Discussion and Analysis of Financial Condition and Results of Operations is included on pages 43 through 68 of this annual report.

Item 7(a). Quantitative and Qualitative Disclosures About Market Risk.

Information related to market risk is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Instrument Market Risk" on page 66 of this annual report.

Item 8. Financial Statements and Supplementary Data.

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

None.

Item 9(a). Controls and Procedures.

In accordance with the Securities Exchange Act of 1934 Rules 13a-15 and 15d-15, 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 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 recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

See page 69 for Management's Report on Internal Control Over Financial Reporting and page 70 for Report of Independent Registered Public Accounting Firm on its assessment of our internal control over financial reporting.

Item 9(b). Other Information.

None.

HALLIBURTON COMPANY
Management's Discussion and Analysis of Financial Condition and Results of Operations

EXECUTIVE OVERVIEW

Financial results

During 2011, we produced revenue of $24.8 billion and operating income of $4.7 billion, reflecting an operating margin of 19%. Revenue increased $6.9 billion, or 38%, from 2010, while operating income increased $1.7 billion, or 57%, from 2010. Overall, these increases were due to our customers' higher capital spending throughout 2011, led by increased drilling activity in unconventional oil and natural gas basins and pricing improvements in North America.

Business outlook

We continue to believe in the strength of the long-term fundamentals of our business. Despite concerns about the global economy, energy demand is expected to continue to increase driven by growth in emerging countries. Furthermore, development of new resources is expected to be more complex resulting in increasing service intensity.

In North America, the United States land rig count and horizontal drilling activity has been growing, led by a shift to oil and liquids-rich shale basins. We believe that natural gas drilling activity will be under pressure until a natural gas oversupply situation is corrected; however, any reduction in natural gas drilling may be offset by an increase in liquids-directed activity. Our 2011 Gulf of Mexico business improved compared to 2010 due to the lifting of the deepwater drilling suspension in the fourth quarter of 2010 and a higher level of drilling permits issued in the second half of 2011. In the fourth quarter of 2011, we saw revenue exceed levels experienced prior to the drilling suspension for the first time. Margins in the Gulf of Mexico, while improving, are not expected to recover to pre-drilling suspension levels until the second half of 2012, as our customers adapt to new regulations. See "Business Environment and Results of Operations," Note 8 to the consolidated financial statements, Item 3. "Legal Proceedings," and Item 1(a), "Risk Factors."

Outside of North America, revenue for 2011 increased from the prior year, while our operating income declined due to highly competitive service pricing in several markets. In the second half of 2011, our operations in Egypt recovered from the turmoil experienced in the first quarter of 2011. Although we have resumed some activity in Libya, any meaningful recovery depends on our customers' ability to reestablish operations. Despite the events that have transpired in the Middle East and North Africa and the impact of lower service pricing negotiated during the worldwide recession, we expect gradual margin improvement outside of North America during 2012 as activity continues to increase and new technologies are introduced.

We have carried out several key initiatives in 2011. These initiatives involve increasing manufacturing production in the Eastern Hemisphere and reinventing our service delivery platform to lower our delivery costs.

Our operating performance and business outlook are described in more detail in "Business Environment and Results of Operations."

Financial markets, liquidity, and capital resources

Since mid-2008, the global financial markets have been somewhat volatile. While this has created additional risks for our business, we believe we have invested our cash balances conservatively and secured sufficient financing to help mitigate any near-term negative impact on our operations. For additional information, see "Liquidity and Capital Resources" and "Business Environment and Results of Operations."

LIQUIDITY AND CAPITAL RESOURCES

We ended 2011 with cash and equivalents of $2.7 billion compared to $1.4 billion at December 31, 2010. As of December 31, 2011, $502 million of the $2.7 billion of cash and equivalents was held by our foreign subsidiaries that would be subject to tax if repatriated. If these funds are needed for our operations in the United States, we would be required to accrue and pay United States taxes to repatriate these funds. However, our intent is to permanently reinvest these funds outside of the United States and our current plans do not demonstrate a need to repatriate them to fund our United States operations. We also held $150 million of short-term, United States Treasury securities classified as marketable securities at December 31, 2011 compared to $653 million of short-term, United States Treasury securities at December 31, 2010.

Significant sources of cash

Cash flows from operating activities contributed $3.7 billion to cash in 2011.

In November 2011, we issued $500 million aggregate principal amount of 3.25% senior notes due 2021 and $500 million aggregate principal amount of 4.5% senior notes due 2041.

During 2011, we sold approximately $1.0 billion of short-term marketable securities.

*Further available sources of cash***.** On February 22, 2011, we entered into an unsecured $2.0 billion five-year revolving credit facility that replaced our then existing $1.2 billion unsecured credit facility established in July 2007. The purpose of the facility is to provide general working capital and credit for other corporate purposes. The full amount of the revolving credit facility was available as of December 31, 2011.

Significant uses of cash

Capital expenditures were $3.0 billion in 2011 and were predominantly made in Halliburton Production Enhancement, Sperry Drilling, Cementing, and Wireline and Perforating. We have also invested additional working capital to support the growth of our business.

During 2011, we purchased $501 million of short-term marketable securities.

We paid $330 million in dividends to our shareholders in 2011.

In October 2011, we completed the acquisition of Multi-Chem Group, LLC (Multi-Chem) in an all cash transaction. Multi-Chem is the fourth-largest provider of production chemicals in North America, delivering specialty chemicals, services and solutions. We paid approximately $880 million for Multi-Chem and other acquisitions in 2011.

Future uses of cash. Capital spending for 2012 is currently expected to be between $3.5 and $4.0 billion. The capital expenditures plan for 2012 is primarily directed toward Halliburton Production Enhancement, Sperry Drilling, Cementing, Completion Tools, and Wireline and Perforating.

We are continuing to explore opportunities for acquisitions that will enhance or augment our current portfolio of services and products, including those with unique technologies or distribution networks in areas where we do not already have large operations.

Subject to Board of Directors approval, we expect to pay quarterly dividends of approximately $83 million during 2012. We also have approximately $1.7 billion remaining available under our share repurchase authorization, which may be used for open market share purchases.

The following table summarizes our significant contractual obligations and other long-term liabilities as of December 31, 2011:

	Payments Due						
Millions of dollars	2012	2013	2014	2015	2016	Thereafter	Total
Long-term debt	$ –	$ –	$ –	$ –	$ –	$ 4,820	$ 4,820
Interest on debt (a)	277	279	281	285	291	5,733	7,146
Operating leases	207	166	112	87	64	164	800
Purchase obligations (b)	2,363	262	284	173	153	173	3,408
Pension funding obligations (c)	22	–	–	–	–	–	22
Other long-term liabilities	12	12	3	3	3	8	41
Total	$ 2,881	$ 719	$ 680	$ 548	$ 511	$ 10,898	$ 16,237

(a) Interest on debt includes 85 years of interest on $300 million of debentures at 7.6% interest that become due in 2096.

(b) Primarily represents certain purchase orders for goods and services utilized in the ordinary course of our business.

(c) Includes international plans and is based on assumptions that are subject to change. We are currently not able to reasonably estimate our contributions for years after 2012. See Note 13 to the consolidated financial statements for further information regarding pension contributions.

We had $274 million of gross unrecognized tax benefits at December 31, 2011, of which we estimate $120 million may require a cash payment. We estimate that $89 million of the cash payment will not be settled within the next 12 months. We are not able to reasonably estimate in which future periods this amount will ultimately be settled and paid.

Other factors affecting liquidity

Financial position in current market. We have $2.7 billion of cash and equivalents and $150 million in investments in marketable securities as of December 31, 2011 and a total of $2.0 billion of available committed bank credit under our revolving credit facility. Furthermore, we have no financial covenants or material adverse change provisions in our bank agreements and our debt maturities extend over a long period of time. Although a portion of earnings from our foreign subsidiaries is reinvested outside the United States indefinitely, we do not consider this to have a significant impact on our liquidity. We currently believe that our capital expenditures, working capital investments, and dividends, if any, in 2012 can be fully funded through cash from operations.

As a result, we believe we have a reasonable amount of liquidity and, if necessary, additional financing flexibility given the current market environment to fund our potential contingent liabilities, if any. However, as discussed above in Item 3, "Legal Proceedings," there are numerous future developments that may arise as a result of the Macondo well incident that could have a material adverse effect on our liquidity.

Guarantee agreements. In the normal course of business, we have agreements with financial institutions under which approximately $1.7 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2011, including $292 million of surety bonds related to Venezuela. See "Business Environment and Results of Operations – International Operations" for further discussion related to Venezuela. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Credit ratings. Credit ratings for our long-term debt remain A2 with Moody's Investors Service and A with Standard & Poor's. The credit ratings on our short-term debt remain P-1 with Moody's Investors Service and A-1 with Standard & Poor's.

Customer receivables. In line with industry practice, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures to pay our invoices due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. For example, we continue to see delays in receiving payment on our receivables from one of our primary customers in Venezuela. If our customers delay paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

BUSINESS ENVIRONMENT AND RESULTS OF OPERATIONS

We operate in approximately 80 countries throughout the world to provide a comprehensive range of discrete and integrated services and products to the energy industry. The majority of our consolidated revenue is derived from the sale of services and products to major, national, and independent oil and natural gas companies worldwide. We serve the upstream oil and natural gas industry throughout the lifecycle of the reservoir, from locating hydrocarbons and managing geological data, to drilling and formation evaluation, well construction and completion, and optimizing production throughout the life of the field. Our two business segments are the Completion and Production segment and the Drilling and Evaluation segment. The industry we serve is highly competitive with many substantial competitors in each segment. In 2011, based upon the location of the services provided and products sold, 55% of our consolidated revenue was from the United States. In 2010, 46% of our consolidated revenue was from the United States. No other country accounted for more than 10% of our revenue during these periods.

Operations in some countries may be adversely affected by unsettled political conditions, acts of terrorism, civil unrest, force majeure, war or other armed conflict, expropriation or other governmental actions, inflation, foreign currency exchange restrictions, and highly inflationary currencies. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country, other than the United States, would be materially adverse to our consolidated results of operations.

Activity levels within our business segments are significantly impacted by spending on upstream exploration, development, and production programs by major, national, and independent oil and natural gas companies. Also impacting our activity is the status of the global economy, which impacts oil and natural gas consumption.

Some of the more significant measures of current and future spending levels of oil and natural gas companies are oil and natural gas prices, the world economy, the availability of credit, government regulation, and global stability, which together drive worldwide drilling activity. Our financial performance is significantly affected by oil and natural gas prices and worldwide rig activity, which are summarized in the following tables.

This table shows the average oil and natural gas prices for West Texas Intermediate (WTI), United Kingdom Brent crude oil, and Henry Hub natural gas:

Average Oil Prices (dollars per barrel)	2011	2010	2009
West Texas Intermediate	$ 95.13	$ 79.36	$ 61.65
United Kingdom Brent	$111.53	$ 79.66	$ 61.49
Average United States Natural Gas Prices (dollars per thousand cubic feet, or Mcf)			
Henry Hub	$ 4.09	$ 4.52	$ 4.06

The historical yearly average rig counts based on the Baker Hughes Incorporated rig count information were as follows:

Land vs. Offshore	2011	2010	2009
United States:			
Land	1,843	1,509	1,042
Offshore (incl. Gulf of Mexico)	32	32	44
Total	1,875	1,541	1,086
Canada:			
Land	422	349	220
Offshore	1	2	1
Total	423	351	221
International (excluding Canada):			
Land	863	789	722
Offshore	304	305	275
Total	1,167	1,094	997
Worldwide total	3,465	2,986	2,304
Land total	3,128	2,647	1,984
Offshore total	337	339	320

Oil vs. Natural Gas	2011	2010	2009
United States (incl. Gulf of Mexico):			
Oil	984	593	282
Natural Gas	891	948	804
Total	1,875	1,541	1,086
Canada:			
Oil	282	201	102
Natural Gas	141	150	119
Total	423	351	221
International (excluding Canada):			
Oil	918	840	776
Natural Gas	249	254	221
Total	1,167	1,094	997
Worldwide total	3,465	2,986	2,304
Oil total	2,184	1,634	1,160
Natural Gas total	1,281	1,352	1,144

Drilling Type	2011	2010	2009
United States (incl. Gulf of Mexico):			
Horizontal	1,074	822	456
Vertical	571	501	433
Directional	230	218	197
Total	1,875	1,541	1,086

Our customers' cash flows, in most instances, depend upon the revenue they generate from the sale of oil and natural gas. Lower oil and natural gas prices usually translate into lower exploration and production budgets. The opposite is true for higher oil and natural gas prices.

WTI oil prices, which generally influence customer spending in North America, have fluctuated throughout 2011, ranging from a high of $113.39 per barrel in April to a low of $75.40 per barrel in October. Outside of North America, customer spending is heavily influenced by Brent oil prices, which have fluctuated during 2011 from a low of $93.52 per barrel in January to a high of $126.64 per barrel in May. The outlook for world petroleum demand for 2012 is mixed, with the International Energy Agency's (IEA) January 2012 "Oil Market Report" forecasting a 1% increase in petroleum demand from 2011 levels. The IEA expects modest declines in mature economies to be more than offset by relatively strong growth in emerging markets.

Henry Hub natural gas prices were relatively stable in the first half of 2011, but declined significantly in the second half, primarily due to an oversupply caused by strong drilling activity in the United States land region and increased pipeline capacity. Natural gas prices during 2011 ranged from a high of $4.92 per Mcf in June to a low of $2.84 per Mcf in November. According to the United States Energy Information Administration (EIA), this trend has continued into the beginning of 2012, with a warmer than expected winter lowering demand and contributing to record-high natural gas inventories. This in turn has caused prices to decline further to the mid-$2.00 range at the end of January of 2012. The EIA's January 2012 "Short Term Energy Outlook" forecast expects United States natural gas demand to increase 2% from 2011 levels as more electricity generation shifts from coal to natural gas.

The outlook thus faces uncertainties as the global recovery continues to remain somewhat fragile. However, we believe that, over the long-term, hydrocarbon demand will generally increase, and this, combined with the underlying trends of smaller and more complex reservoirs, high depletion rates, and the need for continual reserve replacement, should drive the long-term need for our services and products.

North America operations

Volatility in oil and natural gas prices can impact our customers' drilling and production activities. The shift to oil and liquids-rich shale basins that began in 2010 has helped to drive increased service intensity, not only in terms of horsepower required per job, but also in fluid chemistry and other technologies required for these complex reservoirs. This trend has continued in 2011, with horizontal oil-directed drilling activity representing the fastest growing segment of the market. As of December 31, 2011, horizontal-directed rig activity represented approximately 58% of the total rigs in the United States, about 85% higher than peak levels in 2008. These trends have led to increased demand and improved pricing for most of our services and products in our United States land operations.

Going forward, we believe the market conditions are supportive of an increase in overall activity in the United States land market; however, some of our customers began shifting their resources from natural gas to oil and liquids-rich basins in the fourth quarter of 2011. In order to meet our customers' needs, we are redeploying equipment to these oil and liquids-rich basins and making adjustments to our supply chain. Our customer mix also continues to shift towards independent and national oil companies and large independents, which tend to have more stable spending patterns and more sophisticated supply chain management. These factors are reinforcing our belief that revenue for North America can be sustainable; however, growing cost pressure and logistical challenges could moderate our margin levels in 2012.

Deepwater drilling activity in the Gulf of Mexico is continuing to recover due to the issuance of a number of drilling permits. We believe we will see an increase in the level of permit approvals in 2012 leading to additional deepwater rigs arriving over the next several quarters in 2012. Our business in the Gulf of Mexico represented approximately 16% of our North America revenue in 2009, approximately 9% in 2010, and approximately 6% in 2011. In addition, the Gulf of Mexico represented approximately 6% of our consolidated revenue in 2009, approximately 4% in 2010, and approximately 3% in 2011. Longer term, we do not know the extent to which the Macondo well incident or resulting drilling regulations will impact revenue or earnings, as they are dependent on, among other things, governmental approvals for permits, our customers' actions, and the potential movement of deepwater rigs to or from other markets.

International operations

During 2011, revenue outside North America increased 14%, while operating income outside of North America decreased 16% from the prior year, reflecting competitive pricing internationally, especially on larger projects. Latin America revenue increased 34% and operating income increased 60% from the prior year. However, these increases were more than offset by civil unrest and sanctions in North Africa and the continued impact of over capacity leading to pricing pressure. Although some minor work has been performed recently in Libya, we are still awaiting well-defined operational plans from our customers. We do not expect activity levels in Libya to recover to pre-2011 levels until late 2012 or 2013. Our first quarter of 2011 results were impacted by a $59 million, pre-tax, charge in Libya, to reserve for certain doubtful accounts receivable and inventory. Additionally, the second quarter of 2011 results were impacted by a $11 million, pre-tax, charge for employee separation costs, primarily related to our Europe/Africa/CIS regional operations. The third quarter of 2011 results were impacted by a $25 million, pre-tax, impairment charge on an asset held for sale in our Europe/Africa/CIS region. During 2011, we took action to improve the profitability of our Europe/Africa/CIS regional operations, such as our previously disclosed restructuring efforts. We have made substantial progress in our restructuring efforts and believe we are now well positioned to deliver improved profitability in this region in 2012.

The pace of international recovery is lagging that of previous cycles at this stage, despite international rig counts exceeding the prior peak reached in September of 2008. One of the contributing factors for the difference is the decline in offshore rig counts that we have seen with the current cycle. Given the service intensity of offshore work, we believe this resulted in a more extensive impact on the industry's revenues, a more significant capacity overhang, and consequently, a more pronounced drop off in pricing. However, we are anticipating that the industry will experience steady volume increases through 2012 as macroeconomic trends support a more favorable operator spending outlook and new rigs are scheduled to enter the market, which we believe will eventually lead to meaningful absorption of equipment supply and result in the ability to begin to improve pricing for our services. We also believe that international unconventional oil and natural gas projects will contribute to activity improvements, and we plan to leverage our extensive experience in North America to optimize these opportunities. We continue to believe in the long-term prospects of the international market and will align our business accordingly. Consistent with our long-term strategy to grow our operations outside of North America, we also expect to continue to invest capital in our international operations.

Venezuela. In December 2010, the Venezuelan government set the fixed exchange rate at 4.3 Bolívar Fuerte to one United States dollar effective January 1, 2011, eliminating the dual exchange rate scheme implemented in early 2010. This change had no impact on us because we have applied the 4.3 Bolívar Fuerte fixed exchange rate since the previously disclosed January 2010 devaluation.

On May 24, 2011, the United States government imposed sanctions on the state-owned oil company of Venezuela. The sanctions do not, however, apply to that company's subsidiaries and do not prohibit the export of crude oil to the United States. We do not expect these sanctions to have a material impact on our operations in Venezuela.

As of December 31, 2011, our total net investment in Venezuela was approximately $194 million. In addition to this amount, we have $292 million of surety bond guarantees outstanding relating to our Venezuelan operations.

Initiatives and recent contract awards

Following is a brief discussion of some of our recent and current initiatives:

- increasing our market share in the more economic, unconventional plays and deepwater markets by leveraging our broad technology offerings to provide value to our customers through integrated solutions and the ability to more efficiently drill and complete their wells;
- exploring opportunities for acquisitions that will enhance or augment our current portfolio of services and products, including those with unique technologies or distribution networks in areas where we do not already have large operations;
- making key investments in technology and capital to accelerate growth opportunities. To that end, we are continuing to push our technology and manufacturing development, as well as our supply chain, closer to our customers in the Eastern Hemisphere, and we are building a new, world class technology center in Houston, Texas;
- improving working capital, and managing our balance sheet to maximize our financial flexibility. In 2011, we launched a project in North America to redesign our service delivery platform for services through the rollout of improved equipment designs and improved field procedures to reduce cost and improve efficiency;
- expanding capabilities in mature fields to expand our service and consulting capabilities;
- continuing to seek ways to be one of the most cost efficient service providers in the industry by using our scale and breadth of operations; and
- expanding our business with national oil companies.

Contract wins positioning us to grow our operations over the long term include:

- a three-year contract award by Chevron, with extension opportunities, to provide integrated services for shale natural gas exploration in Poland. Under this contract, we will provide drilling services, mud logging, cementing, coiled tubing, slickline services, well testing, completion and hydraulic fracturing, and project management services;
- contract awards by Statoil, with the potential to exceed more than $200 million in value, to provide directional drilling, logging-while-drilling, cementing, drilling fluids, and completion equipment and services for two high-pressure and high-temperature (HP/HT) fields offshore Norway;
- contract awards for equipment and services on two offshore blocks in the South China Sea as part of the first ultra-HP/HT oil and gas drilling project in Asia. Under these contracts, we will provide several-HP/HT technologies for drilling, completions, cementing, and testing, including two industry-first technologies;
- a three-year contract extension by Chevron Thailand, which includes provisions for directional drilling, logging- and measurement- while-drilling services for the ongoing offshore developments in the Gulf of Thailand;
- a contract by Exxon Mobil Iraq Limited to provide drilling services for 15 wells in the West Qurna (Phase I) oil field located in southern Iraq. This is in addition to work awarded in this field by the same customer in 2010. Under this contract, we will provide a complete range of well construction services, utilizing three drilling rigs to deliver the wells; and
- a contract by Statoil to provide integrated drilling and well services in offshore Norway with options up to eight years in duration with extended scope and activity. We will provide directional drilling services, logging- and measurement-while-drilling services, surface data logging, drill bits, hole enlargement and coring services, cementing and pumping services, drilling and completion fluids, completion services, and project management.

RESULTS OF OPERATIONS IN 2011 COMPARED TO 2010

REVENUE: *Millions of dollars*	2011	2010	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 15,143	$ 9,997	$ 5,146	51%
Drilling and Evaluation	9,686	7,976	1,710	21
Total revenue	$ 24,829	$ 17,973	$ 6,856	38%
By geographic region:				
Completion and Production:				
North America	$ 10,907	$ 6,183	$ 4,724	76%
Latin America	1,117	839	278	33
Europe/Africa/CIS	1,746	1,797	(51)	(3)
Middle East/Asia	1,373	1,178	195	17
Total	15,143	9,997	5,146	51
Drilling and Evaluation:				
North America	3,506	2,644	862	33
Latin America	1,865	1,390	475	34
Europe/Africa/CIS	2,210	2,117	93	4
Middle East/Asia	2,105	1,825	280	15
Total	9,686	7,976	1,710	21
Total revenue by region:				
North America	14,413	8,827	5,586	63
Latin America	2,982	2,229	753	34
Europe/Africa/CIS	3,956	3,914	42	1
Middle East/Asia	3,478	3,003	475	16

OPERATING INCOME: *Millions of dollars*	2011	2010	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 3,733	$ 2,032	$ 1,701	84%
Drilling and Evaluation	1,403	1,213	190	16
Corporate and other	(399)	(236)	(163)	69
Total operating income	$ 4,737	$ 3,009	$ 1,728	57%

By geographic region:				
Completion and Production:				
North America	$ 3,341	$ 1,423	$ 1,918	135%
Latin America	159	115	44	38
Europe/Africa/CIS	48	301	(253)	(84)
Middle East/Asia	185	193	(8)	(4)
Total	3,733	2,032	1,701	84
Drilling and Evaluation:				
North America	641	453	188	42
Latin America	305	175	130	74
Europe/Africa/CIS	191	283	(92)	(33)
Middle East/Asia	266	302	(36)	(12)
Total	1,403	1,213	190	16
Total operating income by region (excluding Corporate and other):				
North America	3,982	1,876	2,106	112
Latin America	464	290	174	60
Europe/Africa/CIS	239	584	(345)	(59)
Middle East/Asia	451	495	(44)	(9)

The 38% increase in consolidated revenue in 2011 compared to 2010 was primarily due to higher rig count and increased demand for our services and products in North America. We experienced a 63% increase in North America revenue compared to an approximate 21% increase in average North America rig count during 2011 compared to 2010. Revenue outside of North America was 42% of consolidated revenue in 2011 and 51% of consolidated revenue in 2010.

The 57% increase in consolidated operating income compared to 2010 was mainly due to improved pricing and increased demand in North America, particularly in our Completion and Production division. Operating income in 2011 was adversely impacted by a $25 million, pre-tax, impairment charge on an asset held for sale in the Europe/Africa/CIS region during the third quarter of 2011, $11 million, pre-tax, of employee separation costs in the Eastern Hemisphere during the second quarter of 2011, and a $59 million, pre-tax, charge in Libya, to reserve for certain doubtful accounts receivable and inventory during the first quarter of 2011. Operating income in 2010 was adversely impacted by a $50 million non-cash impairment charge for an oil and natural gas property in Bangladesh in the third quarter of 2010.

Following is a discussion of our results of operations by reportable segment.

Completion and Production increase in revenue compared to 2010 was primarily a result of higher activity in North America. North America revenue rose 76%, primarily due to increased cementing services and higher activity in production enhancement from an increased demand for hydraulic fracturing in the United States. Latin America revenue increased 33% due to improved activity in all product service lines across the region. Europe/Africa/CIS revenue decreased 3%, as less activity in North Africa and lower vessel utilization in the North Sea and Nigeria was partially offset by higher activity in our Boots & Coots product service line in Angola and Norway. Middle East/Asia revenue grew 17% due to higher activity in all product service lines in Australia, Malaysia, and Indonesia, partially offset by lower completion tools sales in China. Revenue outside of North America was 28% of total segment revenue in 2011 and 38% of total segment revenue in 2010.

The Completion and Production segment operating income increase compared to 2010 was primarily due to the North America region, where operating income grew $1.9 billion on higher demand for production enhancement services in unconventional basins located in the United States land market. Latin America operating income increased 38% due to higher demand for cementing services in Colombia, Brazil, and Argentina, partially offset by higher costs and pricing adjustments in Mexico. Europe/Africa/CIS operating income declined 84% due to an impairment charge on an asset held for sale in the third quarter of 2011 and activity disruptions in North Africa, including the Libya-related reserve for certain account receivables and inventory recognized in the first quarter of 2011. Middle East/Asia operating income decreased 4% due to higher costs across most of the region and higher start-up costs associated with the commencement of work in Iraq, which were partially offset by higher activity levels in Australia, Malaysia, and Indonesia.

Drilling and Evaluation revenue increased 21% compared to 2010 as drilling activity improved across all regions, especially North America and Latin America. North America revenue grew 33% on substantial activity increases in the United States land market. Latin America revenue increased 34% due to higher demand in most product services lines in Brazil, Mexico, Venezuela, and Colombia. Europe/Africa/CIS revenue increased 4% due to improved drilling service in Angola, Nigeria, and Norway and increased fluid demand in Egypt, partially offset by lower activity in Libya. Middle East/Asia revenue rose 15% primarily due to the commencement of work in Iraq, increased fluid demand in Southeast Asia, and higher wireline direct sales. Revenue outside North America was 64% of total segment revenue in 2011 and 67% of total segment revenue in 2010.

Segment operating income compared to 2010 increased 16% due to increased activity in North America and Latin America, partially offset by lower activity associated with the disruptions in North Africa and less favorable pricing in the Eastern Hemisphere. North America operating income increased 42% from improved pricing and increased demand for most of our services and products. Latin America operating income grew 74% as a result of activity increases in Mexico, Venezuela, and Brazil. The Europe/Africa/CIS region operating income fell 33% due to costs associated with activity disruptions in North Africa, including the reserve charge for certain account receivables and inventory recognized in the first quarter of 2011, partially offset by improved drilling service in Norway and Nigeria and higher fluid demand in Angola. Middle East/Asia operating income decreased 12% mainly due to start-up costs associated with the commencement of work in Iraq and higher costs in Saudi Arabia. Operating income in 2010 was adversely impacted by a $50 million non-cash impairment charge for an oil and natural gas property in Bangladesh.

Corporate and other expenses were $399 million, including a $37 million environmental-related matter in 2011, compared to $236 million in 2010. The 69% increase was primarily due to higher legal and environmental costs and additional expenses associated with strategic investments in our operating model and creating competitive advantages by repositioning our technology, supply chain, and manufacturing infrastructure.

NONOPERATING ITEMS

Interest expense, net of interest income decreased $34 million in 2011 compared to 2010 primarily due to less interest expense as a result of the retirement of $750 million principal amount of our 5.5% senior notes in October 2010 and lower interest rates on a portion of our debt as a result of our interest rate swaps. This was partially offset by higher interest costs incurred in the fourth quarter of 2011 resulting from our issuance of $1.0 billion of senior notes.

Other, net decreased $32 million from 2010 due to a $31 million loss on foreign currency exchange recognized in 2010 as a result of the devaluation of the Venezuelan Bolívar Fuerte.

Income (loss) from discontinued operations, net increased $206 million in 2011 compared to 2010 primarily due to a $163 million charge, after-tax, recognized in 2011 related to a ruling in an arbitration proceeding between Barracuda & Caratinga Leasing Company B.V. and our former subsidiary, KBR, whom we agreed to indemnify.

RESULTS OF OPERATIONS IN 2010 COMPARED TO 2009

REVENUE: *Millions of dollars*	2010	2009	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 9,997	$ 7,419	$ 2,578	35%
Drilling and Evaluation	7,976	7,256	720	10
Total revenue	$ 17,973	$ 14,675	$ 3,298	22%
By geographic region:				
Completion and Production:				
North America	$ 6,183	$ 3,589	$ 2,594	72%
Latin America	839	887	(48)	(5)
Europe/Africa/CIS	1,797	1,771	26	1
Middle East/Asia	1,178	1,172	6	1
Total	9,997	7,419	2,578	35
Drilling and Evaluation:				
North America	2,644	2,073	571	28
Latin America	1,390	1,294	96	7
Europe/Africa/CIS	2,117	2,177	(60)	(3)
Middle East/Asia	1,825	1,712	113	7
Total	7,976	7,256	720	10
Total revenue by region:				
North America	8,827	5,662	3,165	56
Latin America	2,229	2,181	48	2
Europe/Africa/CIS	3,914	3,948	(34)	(1)
Middle East/Asia	3,003	2,884	119	4

OPERATING INCOME: *Millions of dollars*	2010	2009	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 2,032	$ 1,016	$ 1,016	100%
Drilling and Evaluation	1,213	1,183	30	3
Corporate and other	(236)	(205)	(31)	15
Total operating income	$ 3,009	$ 1,994	$ 1,015	51%
By geographic region:				
Completion and Production:				
North America	$ 1,423	$ 272	$ 1,151	423%
Latin America	115	172	(57)	(33)
Europe/Africa/CIS	301	315	(14)	(4)
Middle East/Asia	193	257	(64)	(25)
Total	2,032	1,016	1,016	100
Drilling and Evaluation:				
North America	453	178	275	154
Latin America	175	187	(12)	(6)
Europe/Africa/CIS	283	380	(97)	(26)
Middle East/Asia	302	438	(136)	(31)
Total	1,213	1,183	30	3
Total operating income by region (excluding Corporate and other):				
North America	1,876	450	1,426	317
Latin America	290	359	(69)	(19)
Europe/Africa/CIS	584	695	(111)	(16)
Middle East/Asia	495	695	(200)	(29)

The 22% increase in consolidated revenue in 2010 compared to 2009 was primarily due to higher rig count and increased demand for our products and services in North America. As a result of an approximate 45% increase in average North America rig count during 2010 compared to 2009, we experienced a 56% increase in North America revenue. Revenue outside of North America was 51% of consolidated revenue in 2010 and 61% of consolidated revenue in 2009.

The 51% increase in consolidated operating income compared to 2009 primarily stemmed from improved pricing and increased demand in North America, particularly in our Completion and Production division. Operating income in 2010 was adversely impacted by a $50 million non-cash impairment charge for an oil and gas property in Bangladesh. Operating income in 2009 was unfavorably impacted by a $73 million charge associated with employee separation costs and a $15 million charge related to the settlement of a customer receivable in Venezuela.

Following is a discussion of our results of operations by reportable segment.

Completion and Production increase in revenue compared to 2009 was primarily a result of higher activity in North America. North America revenue increased 72%, primarily due to increased activity in the United States in cementing services and production enhancement. Latin America revenue decreased 5% due to declines in all product service lines from reduced activity in Mexico and Venezuela, partially offset by increased activity in Argentina and Colombia. Europe/Africa/CIS revenue was flat, as price discounts in the United Kingdom and decreased demand for production enhancement services in Europe and the Caspian partially offset higher activity levels across Africa. Middle East/Asia revenue was also flat, as job delays and a decrease in demand for production enhancement services in the Middle East partially offset increased demand for production enhancement services in Southeast Asia. Revenue outside of North America was 38% of total segment revenue in 2010 and 52% of total segment revenue in 2009.

The Completion and Production segment operating income increase compared to 2009 was primarily due to the North America region, where operating income grew by $1.2 billion, largely due to increases in demand for production enhancement and cementing services which benefitted from increased rig count associated with higher horizontal drilling activity and improved pricing. Latin America operating income fell 33%, primarily due to lower activity across all product services lines in Mexico. Europe/Africa/CIS operating income declined 4% from declines in Europe in completion tools and production enhancement services. Middle East/Asia operating income decreased 25% due to activity declines throughout the region.

Drilling and Evaluation revenue increased compared to 2009 primarily as a result of increased activity in North America, where revenue grew 28%. Latin America revenue grew 7% as increased demand for all products and services in Brazil and Colombia was offset by lower activity in Venezuela and lower demand for wireline and perforating services in Mexico. Europe/Africa/CIS revenue was relatively flat for the period, as higher drilling activity and increased demand for drilling fluid services in Norway and the Commonwealth of Independent States (CIS) was offset by lower drilling activity and decreased demand for drilling fluid services throughout Africa. Middle East/Asia revenue rose 7% as increased demand for drilling fluid services in Southeast Asia and the commencement of activity in Iraq offset decreased demand for drilling services throughout most of the region. Revenue outside North America was 67% of total segment revenue in 2010 and 71% of total segment revenue in 2009.

Segment operating income compared to 2009 was relatively flat due to increased activity in North America being offset by lower activity internationally. North America operating income increased $275 million from improved pricing and increased demand for nearly all products and services. Latin America operating income fell 6%, primarily due to lower drilling activity in Mexico. The Europe/Africa/CIS region operating income fell 26% as decreased demand and higher costs for drilling services, wireline and perforating services, and drilling fluid services in Africa offset increased demand for drilling fluid services in Norway. Middle East/Asia operating income decreased 31% due to a $50 million non-cash impairment charge to an oil and gas property in Bangladesh, higher costs throughout most of the region, lower drilling services in Saudi Arabia, and decreased demand for drilling services and wireline and perforating services in most of Asia Pacific.

Corporate and other expenses were $236 million in 2010 compared to $205 million in 2009. The 2009 results included $5 million in employee separation costs. The 15% increase was primarily related to higher legal costs.

NONOPERATING ITEMS

Interest expense, net of interest income increased $12 million in 2010 compared to 2009 primarily due to the issuance of $2 billion in senior notes in March of 2009.

Other, net in 2010 included a $31 million loss on foreign currency exchange associated with the devaluation of the Venezuelan Bolívar Fuerte.

Income (loss) from discontinued operations, net in 2010 included $62 million of income primarily related to the finalization of a United States tax matter with the Internal Revenue Service and a charge of $17 million, after-tax, related to an indemnity payment on behalf of KBR for a settlement agreement reached with the Federal Government of Nigeria.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the use of judgments and estimates. Our critical accounting policies are described below to provide a better understanding of how we develop our assumptions and judgments about future events and related estimations and how they can impact our financial statements. A critical accounting estimate is one that requires our most difficult, subjective, or complex judgments and assessments and is fundamental to our results of operations. We identified our most critical accounting estimates to be:

- forecasting our effective income tax rate, including our future ability to utilize foreign tax credits and the realizability of deferred tax assets, and providing for uncertain tax positions;
- legal, environmental, and investigation matters;
- valuations of indemnities;
- valuations of long-lived assets, including intangible assets and goodwill;
- purchase price allocation for acquired businesses;
- pensions;
- allowance for bad debts; and
- percentage-of-completion accounting for long-term, construction-type contracts.

We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to the current facts and circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We believe the following are the critical accounting policies used in the preparation of our consolidated financial statements, as well as the significant estimates and judgments affecting the application of these policies. This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this report.

We have discussed the development and selection of these critical accounting policies and estimates with the Audit Committee of our Board of Directors, and the Audit Committee has reviewed the disclosure presented below.

Income tax accounting

We recognize the amount of taxes payable or refundable for the current year and use an asset and liability approach in recognizing the amount of deferred tax liabilities and assets for the future tax consequences of events that have been recognized in our financial statements or tax returns. We apply the following basic principles in accounting for our income taxes:

- a current tax liability or asset is recognized for the estimated taxes payable or refundable on tax returns for the current year;
- a deferred tax liability or asset is recognized for the estimated future tax effects attributable to temporary differences and carryforwards;
- the measurement of current and deferred tax liabilities and assets is based on provisions of the enacted tax law, and the effects of potential future changes in tax laws or rates are not considered; and
- the value of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that, based on available evidence, are not expected to be realized.

We determine deferred taxes separately for each tax-paying component (an entity or a group of entities that is consolidated for tax purposes) in each tax jurisdiction. That determination includes the following procedures:

- identifying the types and amounts of existing temporary differences;
- measuring the total deferred tax liability for taxable temporary differences using the applicable tax rate;
- measuring the total deferred tax asset for deductible temporary differences and operating loss carryforwards using the applicable tax rate;
- measuring the deferred tax assets for each type of tax credit carryforward; and
- reducing the deferred tax assets by a valuation allowance if, based on available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Our methodology for recording income taxes requires a significant amount of judgment in the use of assumptions and estimates. Additionally, we use forecasts of certain tax elements, such as taxable income and foreign tax credit utilization, as well as evaluate the feasibility of implementing tax planning strategies. Given the inherent uncertainty involved with the use of such variables, there can be significant variation between anticipated and actual results. Unforeseen events may significantly impact these variables, and changes to these variables could have a material impact on our income tax accounts related to both continuing and discontinued operations.

We have operations in approximately 80 countries other than the United States. Consequently, we are subject to the jurisdiction of a significant number of taxing authorities. No single jurisdiction has a disproportionately low tax rate. The income earned in these various jurisdictions is taxed on differing bases, including income actually earned, income deemed earned, and revenue-based tax withholding. The final determination of our income tax liabilities involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction. Changes in the operating environment, including changes in tax law and currency/repatriation controls, could impact the determination of our income tax liabilities for a tax year.

Tax filings of our subsidiaries, unconsolidated affiliates, and related entities are routinely examined in the normal course of business by tax authorities. These examinations may result in assessments of additional taxes, which we work to resolve with the tax authorities and through the judicial process. Predicting the outcome of disputed assessments involves some uncertainty. Factors such as the availability of settlement procedures, willingness of tax authorities to negotiate, and the operation and impartiality of judicial systems vary across the different tax jurisdictions and may significantly influence the ultimate outcome. We review the facts for each assessment, and then utilize assumptions and estimates to determine the most likely outcome and provide taxes, interest, and penalties as needed based on this outcome. We provide for uncertain tax positions pursuant to current accounting standards, which prescribe a minimum recognition threshold and measurement methodology that a tax position taken or expected to be taken in a tax return is required to meet before being recognized in the financial statements. The standards also provide guidance for derecognition classification, interest and penalties, accounting in interim periods, disclosure, and transition.

Legal, environmental, and investigation matters

As discussed in Note 8 of our consolidated financial statements, as of December 31, 2011, we have accrued an estimate of the probable and estimable costs for the resolution of some of these legal, environmental, and investigation matters. For other matters for which the liability is not probable and reasonably estimable, we have not accrued any amounts. Attorneys in our legal department monitor and manage all claims filed against us and review all pending investigations. Generally, the estimate of probable costs related to these matters is developed in consultation with internal and outside legal counsel representing us. Our estimates are based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. The accuracy of these estimates is impacted by, among other things, the complexity of the issues and the amount of due diligence we have been able to perform. We attempt to resolve these matters through settlements, mediation, and arbitration proceedings when possible. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected. We have in the past recorded significant adjustments to our initial estimates of these types of contingencies.

Indemnity valuations

We provided indemnification in favor of KBR for a contingent liability related to the Barracuda-Caratinga bolts matter. See Notes 7 and 8 to the consolidated financial statements for further information. Accounting standards require recognition of a third-party indemnity at its inception. Therefore, we recorded our estimate of the fair value of this indemnity as of the date of KBR's separation. The initial amount recorded for the Barracuda-Caratinga indemnity was based upon analysis conducted by a third-party valuation expert. The valuation model employed a probability-weighted cost analysis, with certain assumptions based upon the accumulation of data and knowledge of the relevant issues. The accounting standards state that the subsequent measurement of the liability should not necessarily be based on fair value. The standards reference accounting for subsequent adjustments to this type of liability as you would under the current accounting guidance for contingent liabilities. As such, subsequent adjustments to the indemnity provided to KBR upon separation have been recorded when the loss is both probable and estimable.

Value of long-lived assets, including intangible assets and goodwill

We carry a variety of long-lived assets on our balance sheet including property, plant and equipment, goodwill, and other intangibles. We conduct impairment tests on long-lived assets whenever events or changes in circumstances indicate that the carrying value may not be recoverable and on intangible assets quarterly. Impairment is the condition that exists when the carrying amount of a long-lived asset exceeds its fair value, and any impairment charge that we record reduces our earnings. We review the carrying value of these assets based upon estimated future cash flows while taking into consideration assumptions and estimates including the future use of the asset, remaining useful life of the asset, and service potential of the asset.

Goodwill is the excess of the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed. We test goodwill for impairment annually, during the third quarter, or if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. For purposes of performing the goodwill impairment test our reporting units are the same as our reportable segments, the Completion and Production division and the Drilling and Evaluation division. In September 2011, the Financial Accounting Standards Board (FASB) issued an update to existing guidance on the assessment of goodwill impairment to allow companies the option to perform a qualitative assessment to determine whether further goodwill impairment testing is necessary. The impairment test consists of a two-step process. The first step compares the fair value of a reporting unit with its carrying amount, including goodwill, and utilizes a future cash flow analysis based on the estimates and assumptions of our forecasted long-term growth model. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. If the carrying amount of a reporting unit exceeds its fair value, we perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. Any impairment charge that we record reduces our earnings. Our goodwill impairment assessment indicated the fair value of each of our reporting units exceeded its carrying amount by a significant margin for 2011, 2010, and 2009. See Note 1 to the consolidated financial statements for accounting policies related to long-lived assets and intangible assets.

Acquisitions-purchase price allocation

We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. We use all available information to estimate fair values including quoted market prices, the carrying value of acquired assets, and widely accepted valuation techniques such as discounted cash flows. We engage third-party appraisal firms to assist in fair value determination of inventories, identifiable intangible assets, and any other significant assets or liabilities when appropriate. The judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can materially impact our results of operations.

Pensions

Our pension benefit obligations and expenses are calculated using actuarial models and methods. Two of the more critical assumptions and estimates used in the actuarial calculations are the discount rate for determining the current value of benefit obligations and the expected long-term rate of return on plan assets used in determining net periodic benefit cost. Other critical assumptions and estimates used in determining benefit obligations and cost, including demographic factors such as retirement age, mortality, and turnover, are also evaluated periodically and updated accordingly to reflect our actual experience.

Discount rates are determined annually and are based on the prevailing market rate of a portfolio of high-quality debt instruments with maturities matching the expected timing of the payment of the benefit obligations. Expected long-term rates of return on plan assets are determined annually and are based on an evaluation of our plan assets and historical trends and experience, taking into account current and expected market conditions. Plan assets are comprised primarily of equity and debt securities. As we have both domestic and international plans, these assumptions differ based on varying factors specific to each particular country or economic environment.

The weighted-average discount rate utilized in 2011 to determine the projected benefit obligation at the measurement date for our United Kingdom pension plan, which constituted 74% of our international plans' pension obligations, was 4.9%, compared to a discount rate of 5.5% utilized in 2010. The expected long-term rate of return assumption used for our United Kingdom pension plan expense was 6.7% in 2011 and 2010. The following table illustrates the sensitivity to changes in certain assumptions, holding all other assumptions constant, for our United Kingdom pension plan.

	Effect on	
Millions of dollars	Pretax Pension Expense in 2011	Pension Benefit Obligation at December 31, 2011
25-basis-point decrease in discount rate	$ 1	$ 37
25-basis-point increase in discount rate	$ (1)	$ (35)
25-basis-point decrease in expected long-term rate of return	$ 2	NA
25-basis-point increase in expected long-term rate of return	$ (2)	NA

Our international defined benefit plans reduced pretax income by $27 million in 2011, $28 million in 2010, and $32 million in 2009. Included in these amounts was income from expected pension returns of $47 million in 2011, $43 million in 2010, and $38 million in 2009. Actual returns on international plan assets totaled $13 million in 2011, compared to $72 million in 2010. Our net actuarial loss, net of tax, related to international pension plans at December 31, 2011 was $184 million. In our international plans where employees continue to earn additional benefits for continued service, actuarial gains and losses are being recognized in operating income over a period of 12 to 17 years, which represents the estimated average remaining service of the participant group expected to receive benefits. In our international plans where benefits are not accrued for continued service, actuarial gains and losses are being recognized in operating income over a period of one to 35 years, which represents the estimated average remaining lifetime of the benefit obligations. The broad range of one to 35 years reflects varying maturity levels among these plans.

During 2011, we made contributions of $26 million to fund our international defined benefit plans. We expect to make contributions of approximately $11 million to our international defined benefit plans in 2012.

The actuarial assumptions used in determining our pension benefit obligations may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, and longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations. See Note 13 to the consolidated financial statements for further information related to defined benefit and other postretirement benefit plans.

Allowance for bad debts

We evaluate our accounts receivable through a continuous process of assessing our portfolio on an individual customer and overall basis. This process consists of a thorough review of historical collection experience, current aging status of the customer accounts, financial condition of our customers, and whether the receivables involve retainages. We also consider the economic environment of our customers, both from a marketplace and geographic perspective, in evaluating the need for an allowance. Based on our review of these factors, we establish or adjust allowances for specific customers and the accounts receivable portfolio as a whole. This process involves a high degree of judgment and estimation, and frequently involves significant dollar amounts. Accordingly, our results of operations can be affected by adjustments to the allowance due to actual write-offs that differ from estimated amounts. Our estimates of allowances for bad debts have historically been accurate. Over the last five years, our estimates of allowances for bad debts, as a percentage of notes and accounts receivable before the allowance, have ranged from 1.6% to 3.0%. At December 31, 2011, allowance for bad debts totaled $137 million, or 2.7% of notes and accounts receivable before the allowance, and at December 31, 2010, allowance for bad debts totaled $91 million, or 2.3% of notes and accounts receivable before the allowance. A hypothetical 100 basis point change in our estimate of the collectability of our notes and accounts receivable balance as of December 31, 2011 would have resulted in a $52 million adjustment to 2011 total operating costs and expenses. See Note 3 to the consolidated financial statements for further information.

Percentage of completion

Revenue from certain long-term, integrated project management contracts to provide well construction and completion services is reported on the percentage-of-completion method of accounting. Progress is generally based upon physical progress related to contractually defined units of work. At the outset of each contract, we prepare a detailed analysis of our estimated cost to complete the project. Risks related to service delivery, usage, productivity, and other factors are considered in the estimation process. The recording of profits and losses on long-term contracts requires an estimate of the total profit or loss over the life of each contract. This estimate requires consideration of total contract value, change orders, and claims, less costs incurred and estimated costs to complete. Anticipated losses on contracts are recorded in full in the period in which they become evident. Profits are recorded based upon the total estimated contract profit times the current percentage complete for the contract.

At least quarterly, significant projects are reviewed in detail by senior management. There are many factors that impact future costs, including but not limited to weather, inflation, labor and community disruptions, timely availability of materials, productivity, and other factors as outlined in our Item 1(a), “Risk Factors.” These factors can affect the accuracy of our estimates and materially impact our future reported earnings. Currently, long-term contracts accounted for under the percentage-of-completion method of accounting do not comprise a significant portion of our business. See Note 1 to the consolidated financial statements for further information.

OFF BALANCE SHEET ARRANGEMENTS

At December 31, 2011, we had no material off balance sheet arrangements, except for operating leases. For information on our contractual obligations related to operating leases, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Future uses of cash.”

FINANCIAL INSTRUMENT MARKET RISK

We are exposed to market risk from changes in foreign currency exchange rates and interest rates. We selectively manage these exposures through the use of derivative instruments, including forward exchange contracts and interest rate swaps. The objective of our risk management strategy is to minimize the volatility from fluctuations in foreign currency and interest rates. We do not use derivative instruments for trading purposes. The counterparties to our forward exchange contracts and interest rate swaps are global commercial and investment banks.

There are certain limitations inherent in the sensitivity analyses presented, primarily due to the assumption that interest rates and exchange rates change instantaneously in an equally adverse fashion. In addition, the analyses are unable to reflect the complex market reactions that normally would arise from the market shifts modeled. While this is our best estimate of the impact of the various scenarios, these estimates should not be viewed as forecasts.

Foreign currency exchange risk

We have operations in many international locations and are involved in transactions denominated in currencies other than the United States dollar, our functional currency, which exposes us to foreign currency exchange rate risk. Techniques in managing foreign currency exchange risk include, but are not limited to, foreign currency borrowing and investing and the use of currency derivative instruments. We attempt to selectively manage significant exposures to potential foreign currency exchange losses based on current market conditions, future operating activities, and the associated cost in relation to the perceived risk of loss. The purpose of our foreign currency risk management activities is to minimize the risk that our cash flows from the sale and purchase of services and products in foreign currencies will be adversely affected by changes in exchange rates.

We use forward exchange contracts to manage our exposure to fluctuations in the currencies of the countries in which we do the majority of our international business. These forward exchange contracts are not treated as hedges for accounting purposes, generally have an expiration date of one year or less, and are not exchange traded. While forward exchange contracts are subject to fluctuations in value, the fluctuations are generally offset by the value of the underlying exposures being managed. The use of some of these contracts may limit our ability to benefit from favorable fluctuations in foreign currency exchange rates.

Forward exchange contracts are not utilized to manage exposures in some currencies due primarily to the lack of available markets or cost considerations (non-traded currencies). We attempt to manage our working capital position to minimize foreign currency exposure in non-traded currencies and recognize that pricing for the services and products offered in these countries should account for the cost of exchange rate devaluations. We have historically incurred transaction losses in non-traded currencies.

The notional amounts of open forward exchange contracts were $268 million at December 31, 2011 and $356 million at December 31, 2010. The notional amounts of our forward exchange contracts do not generally represent amounts exchanged by the parties, and thus are not a measure of our exposure or of the cash requirements related to these contracts. As such, cash flows related to these contracts are typically not material. The amounts exchanged are calculated by reference to the notional amounts and by other terms of the contracts, such as exchange rates.

We use a sensitivity analysis model to measure the impact of a 10% adverse movement of foreign currency exchange rates against the United States dollar. A hypothetical 10% adverse change in the value of all our foreign currency positions relative to the United States dollar as of December 31, 2011 would result in a $61 million pre-tax loss for our net monetary assets denominated in currencies other than United States dollars.

Interest rate risk

We are subject to interest rate risk on our long-term debt. Our marketable securities and short-term borrowings do not give rise to significant interest rate risk due to their short-term nature. We had fixed rate long-term debt totaling $4.8 billion at December 31, 2011 and fixed rate long-term debt totaling $3.8 billion at December 31, 2010 with none maturing before May 2017.

During the second quarter of 2011, we entered into a series of interest rate swaps relating to two of our debt instruments with a total notional amount of $1.0 billion at a weighted-average, LIBOR-based, floating rate of 3.57% as of December 31, 2011. We use interest rate swaps to manage the economic effect of fixed rate obligations associated with certain senior notes so that the interest payable on the senior notes effectively becomes linked to variable rates. These interest rate swaps, which expire when the underlying debt matures, are designated as fair value hedges of the underlying debt and are determined to be highly effective.

After consideration of the impact from the interest rate swaps, a hypothetical 100 basis point increase in the LIBOR rate would result in approximately an additional $7 million of interest charges for the year ended December 31, 2011.

Credit risk

Financial instruments that potentially subject us to concentrations of credit risk are primarily cash equivalents, investments in marketable securities, and trade receivables. It is our practice to place our cash equivalents and investments in marketable securities in high quality investments with various institutions. We derive the majority of our revenue from selling products and providing services to the energy industry. Within the energy industry, our trade receivables are generated from a broad and diverse group of customers, although a significant amount of our trade receivables are generated in the United States. We maintain an allowance for losses based upon the expected collectability of all trade accounts receivable.

We do not have any significant concentrations of credit risk with any individual counterparty to our derivative contracts. We select counterparties to those contracts based on our belief that each counterparty's profitability, balance sheet, and capacity for timely payment of financial commitments is unlikely to be materially adversely affected by foreseeable events.

ENVIRONMENTAL MATTERS

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. For information related to environmental matters, see Note 8 to the consolidated financial statements, Item 1(a), "Risk Factors," and Item 3, "Legal Proceedings—Environmental."

NEW ACCOUNTING PRONOUNCEMENTS

In June 2011, the Financial Accounting Standards Board (FASB) issued an update to existing guidance on the presentation of comprehensive income. This update will require the presentation of the components of net income and other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In addition, companies are also required to present reclassification adjustments for items that are reclassified from other comprehensive income to net income on the face of the financial statements. In December 2011, the FASB issued an accounting update to defer the effective date for presentation of reclassification of items out of accumulated other comprehensive income to net income. These updates are effective for fiscal years and interim periods beginning after December 15, 2011. We will adopt the new disclosure requirements for comprehensive income beginning January 1, 2012.

FORWARD-LOOKING INFORMATION

The Private Securities Litigation Reform Act of 1995 provides safe harbor provisions for forward-looking information. Forward-looking information is based on projections and estimates, not historical information. Some statements in this Form 10-K are forward-looking and use words like “may,” “may not,” “believes,” “do not believe,” “plans,” “estimates,” “intends,” “expects,” “do not expect,” “anticipates,” “do not anticipate,” “should,” “likely,” and other expressions. We may also provide oral or written forward-looking information in other materials we release to the public. Forward-looking information involves risk and uncertainties and reflects our best judgment based on current information. Our results of operations can be affected by inaccurate assumptions we make or by known or unknown risks and uncertainties. In addition, other factors may affect the accuracy of our forward-looking information. As a result, no forward-looking information can be guaranteed. Actual events and the results of operations may vary materially.

We do not assume any responsibility to publicly update any of our forward-looking statements regardless of whether factors change as a result of new information, future events, or for any other reason. You should review any additional disclosures we make in our press releases and Forms 10-K, 10-Q, and 8-K filed with or furnished to the SEC. We also suggest that you listen to our quarterly earnings release conference calls with financial analysts.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Halliburton Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in the Securities Exchange Act Rule 13a-15(f).

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation to assess the effectiveness of our internal control over financial reporting as of December 31, 2011 based upon criteria set forth in the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2011, our internal control over financial reporting is effective.

The effectiveness of Halliburton's internal control over financial reporting as of December 31, 2011 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report that is included herein.

HALLIBURTON COMPANY

by

/s/ David J. Lesar	/s/ Mark A. McCollum
David J. Lesar	Mark A. McCollum
Chairman of the Board,	Executive Vice President and
President, and Chief Executive Officer	Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Halliburton Company:

We have audited the accompanying consolidated balance sheets of Halliburton Company and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Halliburton Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Halliburton Company'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 (COSO), and our report dated February 16, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 16, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Halliburton Company:

We have audited Halliburton Company’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 (COSO). Halliburton Company's 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Halliburton Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Halliburton Company and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 16, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 16, 2012

HALLIBURTON COMPANY
Consolidated Statements of Operations

Millions of dollars and shares except per share data	Year Ended December 31 2011	2010	2009
Revenue:			
Services	$ 19,692	$ 13,779	$ 10,832
Product sales	5,137	4,194	3,843
Total revenue	24,829	17,973	14,675
Operating costs and expenses:			
Cost of services	15,432	11,227	9,219
Cost of sales	4,379	3,508	3,255
General and administrative	281	229	207
Total operating costs and expenses	20,092	14,964	12,681
Operating income	4,737	3,009	1,994
Interest expense, net of interest income of $5, $11, and $12	(263)	(297)	(285)
Other, net	(25)	(57)	(27)
Income from continuing operations before income taxes	4,449	2,655	1,682
Provision for income taxes	(1,439)	(853)	(518)
Income from continuing operations	3,010	1,802	1,164
Income (loss) from discontinued operations, net of income tax (provision) benefit of $(18), $75, and $5	(166)	40	(9)
Net income	$ 2,844	$ 1,842	$ 1,155
Noncontrolling interest in net income of subsidiaries	(5)	(7)	(10)
Net income attributable to company	$ 2,839	$ 1,835	$ 1,145
Amounts attributable to company shareholders:			
Income from continuing operations	$ 3,005	$ 1,795	$ 1,154
Income (loss) from discontinued operations, net	(166)	40	(9)
Net income attributable to company	$ 2,839	$ 1,835	$ 1,145
Basic income per share attributable to company shareholders:			
Income from continuing operations	$ 3.27	$ 1.98	$ 1.28
Income (loss) from discontinued operations, net	(0.18)	0.04	(0.01)
Net income per share	$ 3.09	$ 2.02	$ 1.27
Diluted income per share attributable to company shareholders:			
Income from continuing operations	$ 3.26	$ 1.97	$ 1.28
Income (loss) from discontinued operations, net	(0.18)	0.04	(0.01)
Net income per share	$ 3.08	$ 2.01	$ 1.27
Basic weighted average common shares outstanding	918	908	900
Diluted weighted average common shares outstanding	922	911	902

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Balance Sheets

Millions of dollars and shares except per share data	December 31 2011	December 31 2010
Assets		
Current assets:		
Cash and equivalents	$ 2,698	$ 1,398
Receivables (less allowance for bad debts of $137 and $91)	5,084	3,924
Inventories	2,570	1,940
Investments in marketable securities	150	653
Current deferred income taxes	321	257
Other current assets	754	714
Total current assets	11,577	8,886
Property, plant, and equipment (net of accumulated depreciation of $7,096 and $6,064)	8,492	6,842
Goodwill	1,776	1,315
Other assets	1,832	1,254
Total assets	$ 23,677	$ 18,297
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 1,826	$ 1,139
Accrued employee compensation and benefits	862	716
Deferred revenue	309	266
Other current liabilities	1,124	636
Total current liabilities	4,121	2,757
Long-term debt	4,820	3,824
Employee compensation and benefits	534	487
Other liabilities	986	842
Total liabilities	10,461	7,910
Shareholders' equity:		
Common shares, par value $2.50 per share – authorized 2,000 shares, issued 1,073 shares and 1,069 shares	2,683	2,674
Paid-in capital in excess of par value	455	339
Accumulated other comprehensive loss	(273)	(240)
Retained earnings	14,880	12,371
Treasury stock, at cost – 152 and 159 shares	(4,547)	(4,771)
Company shareholders' equity	13,198	10,373
Noncontrolling interest in consolidated subsidiaries	18	14
Total shareholders' equity	13,216	10,387
Total liabilities and shareholders' equity	$ 23,677	$ 18,297

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Shareholders' Equity

Millions of dollars	2011	2010	2009
Balance at January 1	$ 10,387	$ 8,757	$ 7,744
Dividends and other transactions with shareholders	19	(287)	(144)
Treasury shares issued for acquisition	–	103	–
Comprehensive income:			
Net income	2,844	1,842	1,155
Defined benefit and other postretirement plans adjustments	(34)	(27)	2
Other	–	(1)	–
Total comprehensive income	2,810	1,814	1,157
Balance at December 31	$ 13,216	$10,387	$ 8,757

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Cash Flows

Millions of dollars	Year Ended December 31 2011	2010	2009
Cash flows from operating activities:			
Net income	$ 2,844	$ 1,842	$ 1,155
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation, depletion, and amortization	1,359	1,119	931
Payments related to KBR TSKJ matters	(6)	(177)	(417)
(Benefit) provision for deferred income taxes, continuing operations	(30)	124	274
(Income) loss from discontinued operations	166	(40)	9
Other changes:			
Receivables	(1,218)	(902)	869
Inventories	(564)	(331)	232
Accounts payable	649	330	(118)
Other	484	247	(529)
Total cash flows from operating activities	3,684	2,212	2,406
Cash flows from investing activities:			
Capital expenditures	(2,953)	(2,069)	(1,864)
Sales of marketable securities	1,001	1,925	300
Purchases of marketable securities	(501)	(1,282)	(1,620)
Acquisitions of business assets, net of cash acquired	(880)	(523)	(55)
Other investing activities	143	194	154
Total cash flows from investing activities	(3,190)	(1,755)	(3,085)
Cash flows from financing activities:			
Proceeds from long-term borrowings, net of offering costs	978	–	1,975
Payments on long-term borrowings	–	(790)	(31)
Dividends to shareholders	(330)	(327)	(324)
Proceeds from exercises of stock options	160	102	74
Payments to reacquire common stock	(43)	(141)	(17)
Other financing activities	68	42	(7)
Total cash flows from financing activities	833	(1,114)	1,670
Effect of exchange rate changes on cash	(27)	(27)	(33)
Increase (decrease) in cash and equivalents	1,300	(684)	958
Cash and equivalents at beginning of year	1,398	2,082	1,124
Cash and equivalents at end of year	$ 2,698	$ 1,398	$ 2,082
Supplemental disclosure of cash flow information:			
Cash payments during the year for:			
Interest	$ 261	$ 310	$ 251
Income taxes	$ 1,285	$ 804	$ 485

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Notes to Consolidated Financial Statements

Note 1. Description of Company and Significant Accounting Policies

Description of Company

Halliburton Company's predecessor was established in 1919 and incorporated under the laws of the State of Delaware in 1924. We are one of the world's largest oilfield services companies. Our two business segments are the Completion and Production segment and the Drilling and Evaluation segment. We provide a comprehensive range of services and products for the exploration, development, and production of oil and natural gas around the world.

Use of estimates

Our financial statements are prepared in conformity with United States generally accepted accounting principles, requiring us to make estimates and assumptions that affect:

- the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements; and
- the reported amounts of revenue and expenses during the reporting period.

We believe the most significant estimates and assumptions are associated with the forecasting of our effective income tax rate and the valuation of deferred taxes, legal and environmental reserves, indemnity valuations, long-lived asset valuations, purchase price allocations, pensions, allowance for bad debts, and percentage-of-completion accounting for long-term contracts. Ultimate results could differ from our estimates.

Basis of presentation

The consolidated financial statements include the accounts of our company and all of our subsidiaries that we control or variable interest entities for which we have determined that we are the primary beneficiary. All material intercompany accounts and transactions are eliminated. Investments in companies in which we have significant influence are accounted for using the equity method of accounting. If we do not have significant influence, we use the cost method of accounting.

In 2011, we adopted the provisions of new accounting standards. See Note 14 for further information. All periods presented reflect these changes.

Revenue recognition

Overall. Our services and products are generally sold based upon purchase orders or contracts with our customers that include fixed or determinable prices but do not include right of return provisions or other significant post-delivery obligations. Our products are produced in a standard manufacturing operation, even if produced to our customer's specifications. We recognize revenue from product sales when title passes to the customer, the customer assumes risks and rewards of ownership, collectability is reasonably assured, and delivery occurs as directed by our customer. Service revenue, including training and consulting services, is recognized when the services are rendered and collectability is reasonably assured. Rates for services are typically priced on a per day, per meter, per man-hour, or similar basis.

Software sales. Sales of perpetual software licenses, net of any deferred maintenance and support fees, are recognized as revenue upon shipment. Sales of time-based licenses are recognized as revenue over the license period. Maintenance and support fees are recognized as revenue ratably over the contract period, usually a one-year duration.

Percentage of completion. Revenue from certain long-term, integrated project management contracts to provide well construction and completion services is reported on the percentage-of-completion method of accounting. Progress is generally based upon physical progress related to contractually defined units of work. Physical percent complete is determined as a combination of input and output measures as deemed appropriate by the circumstances. All known or anticipated losses on contracts are provided for when they become evident. Cost adjustments that are in the process of being negotiated with customers for extra work or changes in the scope of work are included in revenue when collection is deemed probable.

Research and development

Research and development costs are expensed as incurred. Research and development costs were $401 million in 2011, $366 million in 2010, and $325 million in 2009.

Cash equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Inventories

Inventories are stated at the lower of cost or market. Cost represents invoice or production cost for new items and original cost less allowance for condition for used material returned to stock. Production cost includes material, labor, and manufacturing overhead. Some domestic manufacturing and field service finished products and parts inventories for drill bits, completion products, and bulk materials are recorded using the last-in, first-out method. The remaining inventory is recorded on the average cost method. We regularly review inventory quantities on hand and record provisions for excess or obsolete inventory based primarily on historical usage, estimated product demand, and technological developments.

Allowance for bad debts

We establish an allowance for bad debts through a review of several factors, including historical collection experience, current aging status of the customer accounts, and financial condition of our customers. Our policy is to write off bad debts when the customer accounts are determined to be uncollectible.

Property, plant, and equipment

Other than those assets that have been written down to their fair values due to impairment, property, plant, and equipment are reported at cost less accumulated depreciation, which is generally provided on the straight-line method over the estimated useful lives of the assets. Accelerated depreciation methods are also used for tax purposes, wherever permitted. Upon sale or retirement of an asset, the related costs and accumulated depreciation are removed from the accounts and any gain or loss is recognized. Planned major maintenance costs are generally expensed as incurred. Expenditures for additions, modifications, and conversions are capitalized when they increase the value or extend the useful life of the asset.

Goodwill and other intangible assets

We record as goodwill the excess purchase price over the fair value of the tangible and identifiable intangible assets acquired. During 2011, we recorded an additional $424 million in goodwill arising from 2011 acquisitions, of which $411 million related to the Completion and Production segment and $13 million related to the Drilling and Evaluation segment. The reported amounts of goodwill for each reporting unit are reviewed for impairment on an annual basis, during the third quarter, and more frequently when negative conditions such as significant current or projected operating losses exist. In September 2011, the Financial Accounting Standards Board (FASB) issued an update to existing guidance on the assessment of goodwill impairment to allow companies the option to perform a qualitative assessment to determine whether further goodwill impairment testing is necessary. The annual impairment test for goodwill is a two-step process and involves comparing the estimated fair value of each reporting unit to the reporting unit's carrying value, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired, and the second step of the impairment test is unnecessary. If the carrying amount of a reporting unit exceeds its fair value, the second step of the goodwill impairment test would be performed to measure the amount of impairment loss to be recorded, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. Our goodwill impairment assessment indicated the fair value of each of our reporting units exceeded its carrying amount by a significant margin for 2011, 2010, and 2009. In addition, there were no triggering events that occurred in 2011, 2010, or 2009 requiring us to perform additional impairment reviews.

We amortize other identifiable intangible assets with a finite life on a straight-line basis over the period which the asset is expected to contribute to our future cash flows, ranging from three to 20 years. The components of these other intangible assets generally consist of patents, license agreements, non-compete agreements, trademarks, and customer lists and contracts.

Evaluating impairment of long-lived assets

When events or changes in circumstances indicate that long-lived assets other than goodwill may be impaired, an evaluation is performed. For an asset classified as held for use, the estimated future undiscounted cash flows associated with the asset are compared to the asset's carrying amount to determine if a write-down to fair value is required. When an asset is classified as held for sale, the asset's book value is evaluated and adjusted to the lower of its carrying amount or fair value less cost to sell. In addition, depreciation and amortization is ceased while it is classified as held for sale.

Income taxes

We recognize the amount of taxes payable or refundable for the year. In addition, deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in the financial statements or tax returns. A valuation allowance is provided for deferred tax assets if it is more likely than not that these items will not be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences, net of the existing valuation allowances.

We recognize interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations in our consolidated statements of operations.

We generally do not provide income taxes on the undistributed earnings of non-United States subsidiaries because such earnings are intended to be reinvested indefinitely to finance foreign activities. These additional foreign earnings could be subject to additional tax if remitted, or deemed remitted, as a dividend; however, it is not practicable to estimate the additional amount, if any, of taxes payable. Taxes are provided as necessary with respect to earnings that are not permanently reinvested.

Derivative instruments

At times, we enter into derivative financial transactions to hedge existing or projected exposures to changing foreign currency exchange rates and interest rates. We do not enter into derivative transactions for speculative or trading purposes. We recognize all derivatives on the balance sheet at fair value. Derivatives that are not hedges are adjusted to fair value and reflected through the results of operations. If the derivative is designated as a hedge, depending on the nature of the hedge, changes in the fair value of derivatives are either offset against:

- the change in fair value of the hedged assets, liabilities, or firm commitments through earnings; or
- recognized in other comprehensive income until the hedged item is recognized in earnings.

The ineffective portion of a derivative's change in fair value is recognized in earnings. Recognized gains or losses on derivatives entered into to manage foreign currency exchange risk are included in "Other, net" on the consolidated statements of operations. Gains or losses on interest rate derivatives are included in "Interest expense, net."

Foreign currency translation

Foreign entities whose functional currency is the United States dollar translate monetary assets and liabilities at year-end exchange rates, and nonmonetary items are translated at historical rates. Income and expense accounts are translated at the average rates in effect during the year, except for depreciation, cost of product sales and revenue, and expenses associated with nonmonetary balance sheet accounts, which are translated at historical rates. Gains or losses from changes in exchange rates are recognized in our consolidated statements of operations in "Other, net" in the year of occurrence.

Stock-based compensation

Stock-based compensation cost is measured at the date of grant, based on the calculated fair value of the award, and is recognized as expense over the employee's service period, which is generally the vesting period of the equity grant. Additionally, compensation cost is recognized based on awards ultimately expected to vest, therefore, we have reduced the cost for estimated forfeitures based on historical forfeiture rates. Forfeitures are estimated at the time of grant and revised in subsequent periods to reflect actual forfeitures. See Note 10 for additional information related to stock-based compensation.

Note 2. Business Segment and Geographic Information

We operate under two divisions, which form the basis for the two operating segments we report: the Completion and Production segment and the Drilling and Evaluation segment.

Completion and Production delivers cementing, stimulation, intervention, pressure control, specialty chemicals, artificial lift, and completion services. The segment consists of Halliburton Production Enhancement, Cementing, Completion Tools, Boots & Coots, and Multi-Chem.

Halliburton Production Enhancement services include stimulation services and sand control services. Stimulation services optimize oil and natural gas reservoir production through a variety of pressure pumping services, nitrogen services, and chemical processes, commonly known as hydraulic fracturing and acidizing. Sand control services include fluid and chemical systems and pumping services for the prevention of formation sand production.

Cementing services involve bonding the well and well casing while isolating fluid zones and maximizing wellbore stability. Our cementing service line also provides casing equipment.

Completion Tools includes subsurface safety valves and flow control equipment, surface safety systems, packers and specialty completion equipment, intelligent completion systems, expandable liner hanger systems, sand control systems, well servicing tools, and reservoir performance services. Reservoir performance services include testing tools, real-time reservoir analysis, and data acquisition services.

Boots & Coots includes well intervention services, pressure control, equipment rental tools and services, and pipeline and process services.

Multi-Chem includes oilfield production and completion chemicals and services that address production, processing, and transportation challenges.

Drilling and Evaluation provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, and optimize their well construction activities. The segment consists of Halliburton Drill Bits and Services, Wireline & Perforating, Testing and Subsea, Baroid, Sperry Drilling, Landmark Software and Services, and Halliburton Consulting and Project Management.

Halliburton Drill Bits and Services provides roller cone rock bits, fixed cutter bits, hole enlargement, and related downhole tools and services used in drilling oil and natural gas wells. In addition, coring equipment and services are provided to acquire cores of the formation drilled for evaluation.

Wireline and Perforating services include open-hole wireline services that provide information on formation evaluation, including resistivity, porosity, density, rock mechanics, and fluid sampling. Also offered are cased-hole and slickline services, which provide cement bond evaluation, reservoir monitoring, pipe evaluation, pipe recovery, mechanical services, well intervention, perforating, and borehole seismic services. Perforating services include tubing-conveyed perforating services and products. Borehole seismic services include fracture analysis and mapping.

Testing and Subsea services provide acquisition and analysis of dynamic reservoir information and reservoir optimization solutions to the oil and natural gas industry utilizing downhole test tools, data acquisition services using telemetry and electronic memory recording, fluid sampling, surface well testing, subsea safety systems, and reservoir engineering services.

Baroid provides drilling fluid systems, performance additives, completion fluids, solids control, specialized testing equipment, and waste management services for oil and natural gas drilling, completion, and workover operations.

Sperry Drilling provides drilling systems and services. These services include directional and horizontal drilling, measurement-while-drilling, logging-while-drilling, surface data logging, multilateral systems, underbalanced applications, and rig site information systems. Our drilling systems offer directional control for precise wellbore placement while providing important measurements about the characteristics of the drill string and geological formations while drilling wells. Real-time operating capabilities enable the monitoring of well progress and aid decision-making processes.

Landmark Software and Services is a supplier of integrated exploration, drilling, and production software information systems, as well as consulting and data management services for the upstream oil and natural gas industry.

Halliburton Consulting and Project Management provides oilfield project management and integrated solutions to independent, integrated, and national oil companies. These offerings make use of all of our oilfield services, products, technologies, and project management capabilities to assist our customers in optimizing the value of their oil and natural gas assets.

Corporate and other includes expenses related to support functions and corporate executives. Also included are certain gains and losses that are not attributable to a particular business segment. "Corporate and other" also represents assets not included in a business segment and is primarily composed of cash and equivalents, deferred tax assets, and marketable securities.

Intersegment revenue and revenue between geographic areas are immaterial. Our equity in earnings and losses of unconsolidated affiliates that are accounted for under the equity method of accounting is included in revenue and operating income of the applicable segment.

The following tables present information on our business segments.

Operations by business segment

	Year Ended December 31		
Millions of dollars	2011	2010	2009
Revenue:			
Completion and Production	$ 15,143	$ 9,997	$ 7,419
Drilling and Evaluation	9,686	7,976	7,256
Total revenue	$ 24,829	$ 17,973	$ 14,675
Operating income:			
Completion and Production	$ 3,733	$ 2,032	$ 1,016
Drilling and Evaluation	1,403	1,213	1,183
Total operations	5,136	3,245	2,199
Corporate and other	(399)	(236)	(205)
Total operating income	$ 4,737	$ 3,009	$ 1,994
Interest expense, net of interest income	$ (263)	$ (297)	$ (285)
Other, net	(25)	(57)	(27)
Income from continuing operations before income taxes	$ 4,449	$ 2,655	$ 1,682
Capital expenditures:			
Completion and Production	$ 1,669	$ 1,010	$ 900
Drilling and Evaluation	1,231	1,058	959
Corporate and other	53	1	5
Total	$ 2,953	$ 2,069	$ 1,864
Depreciation, depletion, and amortization:			
Completion and Production	$ 680	$ 537	$ 437
Drilling and Evaluation	676	578	490
Corporate and other	3	4	4
Total	$ 1,359	$ 1,119	$ 931

Millions of dollars	December 31 2011	2010
Total assets:		
Completion and Production	$ 10,953	$ 7,815
Drilling and Evaluation	8,212	7,088
Shared assets	1,249	942
Corporate and other	3,263	2,452
Total	$ 23,677	$ 18,297

Not all assets are associated with specific segments. Those assets specific to segments include receivables, inventories, certain identified property, plant, and equipment (including field service equipment), equity in and advances to related companies, and goodwill. The remaining assets, such as cash, are considered to be shared among the segments.

Revenue by country is determined based on the location of services provided and products sold.

Operations by geographic area

Millions of dollars	Year Ended December 31 2011	2010	2009
Revenue:			
United States	$ 13,548	$ 8,209	$ 5,248
Other countries	11,281	9,764	9,427
Total	$ 24,829	$ 17,973	$ 14,675

Millions of dollars	December 31 2011	2010
Long-lived assets:		
United States	$ 6,692	$ 5,389
Other countries	5,189	3,821
Total	$ 11,881	$ 9,210

Note 3. Receivables

Our trade receivables are generally not collateralized. At December 31, 2011, 45% of our gross trade receivables were from customers in the United States. At December 31, 2010, 36% of our gross trade receivables were from customers in the United States. No other country or single customer accounted for more than 10% of our gross trade receivables at these dates.

The following table presents a rollforward of our allowance for bad debts for 2009, 2010, and 2011.

Millions of dollars Allowance for bad debts	Balance at Beginning of Period	Charged to Costs and Expenses	Write-Offs	Balance at End of Period
Year ended December 31, 2009:	$ 60	$ 37	$ (7)	$ 90
Year ended December 31, 2010:	90	5	(4)	91
Year ended December 31, 2011:	91	53	(7)	137

Note 4. Inventories

Inventories are stated at the lower of cost or market. In the United States, we manufacture certain finished products and parts inventories for drill bits, completion products, bulk materials, and other tools that are recorded using the last-in, first-out method, which totaled $160 million at December 31, 2011 and $108 million at December 31, 2010. If the average cost method had been used, total inventories would have been $36 million higher than reported at December 31, 2011 and $34 million higher than reported at December 31, 2010. The cost of the remaining inventory was recorded on the average cost method. Inventories consisted of the following:

	December 31	
Millions of dollars	2011	2010
Finished products and parts	$ 1,801	$ 1,369
Raw materials and supplies	673	496
Work in process	96	75
Total	$ 2,570	$ 1,940

Finished products and parts are reported net of obsolescence reserves of $108 million at December 31, 2011 and $88 million at December 31, 2010.

Note 5. Property, Plant, and Equipment

Property, plant, and equipment were composed of the following:

	December 31	
Millions of dollars	2011	2010
Land	$ 123	$ 105
Buildings and property improvements	1,609	1,438
Machinery, equipment, and other	13,856	11,363
Total	15,588	12,906
Less accumulated depreciation	7,096	6,064
Net property, plant, and equipment	$ 8,492	$ 6,842

Classes of assets, excluding oil and natural gas investments, are depreciated over the following useful lives:

	Buildings and Property Improvements	
	2011	2010
1 – 10 years	13%	13%
11 – 20 years	47%	46%
21 – 30 years	13%	13%
31 – 40 years	27%	28%

	Machinery, Equipment, and Other	
	2011	2010
1 – 5 years	19%	19%
6 – 10 years	75%	74%
11 – 20 years	6%	7%

Note 6. Debt

Long-term debt consisted of the following:

Millions of dollars	December 31 2011	2010
6.15% senior notes due September 2019	$ 997	$ 997
7.45% senior notes due September 2039	995	995
6.7% senior notes due September 2038	800	800
3.25% senior notes due November 2021	498	–
4.5% senior notes due November 2041	498	–
5.9% senior notes due September 2018	400	400
7.6% senior debentures due August 2096	293	293
8.75% senior debentures due February 2021	184	184
Other	155	155
Total long-term debt (due 2017 and thereafter)	$ 4,820	$ 3,824

Senior debt

All of our senior notes and debentures rank equally with our existing and future senior unsecured indebtedness, have semiannual interest payments, and no sinking fund requirements. We may redeem all of our senior notes from time to time or all of the notes of each series at any time at the applicable redemption prices, plus accrued and unpaid interest. Our 7.6% and 8.75% senior debentures may not be redeemed prior to maturity.

Revolving credit facilities

In February 2011, we entered into a new unsecured $2.0 billion five-year revolving credit facility that replaced our then existing $1.2 billion unsecured credit facility established in July 2007. The purpose of the facility is to provide general working capital and credit for other corporate purposes. The full amount of the revolving credit facility was available as of December 31, 2011.

Note 7. KBR Separation

During 2007, we completed the separation of KBR, Inc. (KBR) from us by exchanging KBR common stock owned by us for our common stock. In addition, we recorded a liability reflecting the estimated fair value of the indemnities provided to KBR as described below. Since the separation, we have recorded adjustments to reflect changes to our estimation of our remaining obligation. All such adjustments are recorded in "Income (loss) from discontinued operations, net of income tax (provision) benefit."

We entered into various agreements relating to the separation of KBR, including, among others, a master separation agreement and a tax sharing agreement. We agreed to provide indemnification in favor of KBR under the master separation agreement for all out-of-pocket cash costs and expenses, or cash settlements or cash arbitration awards in lieu thereof, KBR may incur after the effective date of the master separation agreement as a result of the replacement of the subsea flowline bolts installed in connection with the Barracuda-Caratinga project. During the third quarter of 2011, an arbitration award of $201 million was issued against KBR. Also, under the master separation agreement, we have indemnified KBR for certain losses arising from investigations and charges brought under the United States Foreign Corrupt Practices Act (FCPA) or similar foreign statutes, laws, rules, or regulations in each case related to the construction of a natural gas liquefaction complex and related facilities at Bonny Island in Rivers State, Nigeria by a consortium of engineering firms comprised of Technip SA of France, Snamprogetti Netherlands B.V., JGC Corporation of Japan, and Kellogg Brown & Root LLC (TSKJ), each of which had an approximate 25% beneficial interest in the venture. Part of KBR's ownership in TSKJ was held through M.W. Kellogg Limited, a United Kingdom joint venture and subcontractor on the Bonny Island project in which KBR beneficially owned a 55% interest at the time of the execution of the master separation agreement. The TSKJ investigations and charges have been resolved. At this time, no other claims by governmental authorities in any jurisdictions have been asserted against the indemnified parties.

The tax sharing agreement provides for allocations of United States and certain other jurisdiction tax liabilities between us and KBR. The tax sharing agreement is complex, and finalization of amounts owed between KBR and us under the tax sharing agreement can occur only after income tax audits are completed by the taxing authorities and both parties have had time to analyze the results. Substantially all income tax audits are now complete, and we are in the process of providing relevant documents to KBR and discussing the amounts due under the agreement. There can be no guarantee that the parties will agree on the allocations of tax liabilities, and the process may take several quarters or more to complete.

Amounts accrued relating to our remaining KBR liabilities are primarily included in "Other liabilities" on the consolidated balance sheets and totaled $201 million as of December 31, 2011 and $63 million as of December 31, 2010. See Note 8 for further discussion of the Barracuda-Caratinga matter.

Note 8. Commitments and Contingencies

The Gulf of Mexico/Macondo well incident

Overview. The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for the lease operator, BP Exploration & Production, Inc. (BP Exploration), an indirect wholly owned subsidiary of BP p.l.c. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. Crude oil flowing from the well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. Numerous attempts at estimating the volume of oil spilled have been made by various groups, and on August 2, 2010 the federal government published an estimate that approximately 4.9 million barrels of oil were discharged from the well. Efforts to contain the flow of hydrocarbons from the well were led by the United States government and by BP p.l.c., BP Exploration, and their affiliates (collectively, BP). The flow of hydrocarbons from the well ceased on July 15, 2010, and the well was permanently capped on September 19, 2010. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

We are currently unable to estimate the impact the Macondo well incident will have on us. The multi-district litigation (MDL) trial referred to below is scheduled to begin in late February 2012, and recently there have been and we expect there will continue to be orders and rulings of the court that impact the MDL. Moreover, as discussed below, BP has in the last nine months settled litigation with several other defendants in the MDL. We cannot predict the outcome of the many lawsuits and investigations relating to the Macondo well incident, including whether the MDL will proceed to trial, the results of any such trial, or whether we might settle with one or more of the parties to any lawsuit or investigation. Given the numerous potential future developments relating to the MDL and other lawsuits and investigations, we are unable to conclude whether we will incur a loss. As of December 31, 2011, we have not accrued any amounts related to this matter because we have not determined that a loss is probable and a reasonable estimate of a loss or range of loss related to this matter cannot be made. As a result of any future developments, some of which could occur as soon as within the next few months, we may adjust our liability assessment, and liabilities arising out of this matter could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Investigations and Regulatory Action. The United States Coast Guard, a component of the United States Department of Homeland Security, and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly known as the Minerals Management Service (MMS) and which was replaced effective October 1, 2011 by two new, independent bureaus – the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM)), a bureau of the United States Department of the Interior, shared jurisdiction over the investigation into the Macondo well incident and formed a joint investigation team that reviewed information and held hearings regarding the incident (Marine Board Investigation). We were named as one of the 16 parties-in-interest in the Marine Board Investigation. The Marine Board Investigation, as well as investigations of the incident that were conducted by The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) and the National Academy of Sciences, have been completed, and reports issued as a result of those investigations are discussed below. In addition, the Chemical Safety Board is conducting an investigation to examine the root causes of the accidental release of hydrocarbons from the Macondo well, including an examination of key technical factors, the safety cultures involved, and the effectiveness of relevant laws, regulations, and industry standards.

In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. The suspension was lifted in October 2010. Later, the Department of the Interior issued new guidance and regulations for drillers that intend to resume deepwater drilling activity and has proposed additional regulations. Despite the fact that the drilling suspension was lifted, the BOEMRE did not issue permits for the resumption of drilling for an extended period of time, and we experienced a significant reduction in our Gulf of Mexico operations. In the first quarter of 2011, the BOEMRE resumed the issuance of drilling permits, and activity has gradually recovered since that time, although there can be no assurance of future activity levels in the Gulf of Mexico. For additional information, see Part II, Item 1(a), "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations."

DOJ Investigations and Actions. On June 1, 2010, the United States Attorney General announced that the Department of Justice (DOJ) was launching civil and criminal investigations into the Macondo well incident to closely examine the actions of those involved, and that the DOJ was working with attorneys general of states affected by the Macondo well incident. The DOJ announced that it was reviewing, among other traditional criminal statutes, possible violations of and liabilities under The Clean Water Act (CWA), The Oil Pollution Act of 1990 (OPA), The Migratory Bird Treaty Act of 1918 (MBTA), and the Endangered Species Act of 1973 (ESA). As part of its criminal investigation, the DOJ is examining certain aspects of our conduct after the incident, including with respect to record-keeping, record retention, post-incident testing, securities filings, and public statements by us or our employees, to evaluate whether there has been any violation of federal law.

The CWA provides authority for civil and criminal penalties for discharges of oil into or upon navigable waters of the United States, adjoining shorelines, or in connection with the Outer Continental Shelf Lands Act (OCSLA) in quantities that are deemed harmful. A single discharge event may result in the assertion of numerous violations under the CWA. Criminal sanctions under the CWA can be assessed for negligent discharges (up to $50,000 per day per violation), for knowing discharges (up to $100,000 per day per violation), and for knowing endangerment (up to $2 million per violation), and federal agencies could be precluded from contracting with a company that is criminally sanctioned under the CWA. Civil proceedings under the CWA can be commenced against an "owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged" in violation of the CWA. The civil penalties that can be imposed against responsible parties range from up to $1,100 per barrel of oil discharged in the case of those found strictly liable to $4,300 per barrel of oil discharged in the case of those found to have been grossly negligent.

The OPA establishes liability for discharges of oil from vessels, onshore facilities, and offshore facilities into or upon the navigable waters of the United States. Under the OPA, the "responsible party" for the discharging vessel or facility is liable for removal and response costs as well as for damages, including recovery costs to contain and remove discharged oil and damages for injury to natural resources and real or personal property, lost revenues, lost profits, and lost earning capacity. The cap on liability under the OPA is the full cost of removal of the discharged oil plus up to $75 million for damages, except that the $75 million cap does not apply in the event the damage was proximately caused by gross negligence or the violation of certain federal safety, construction or operating standards. The OPA defines the set of responsible parties differently depending on whether the source of the discharge is a vessel or an offshore facility. Liability for vessels is imposed on owners and operators; liability for offshore facilities is imposed on the holder of the permit or lessee of the area in which the facility is located.

The MBTA and the ESA provide penalties for injury and death to wildlife and bird species. The MBTA provides that violators are strictly liable and such violations are misdemeanor crimes subject to fines of up to $15,000 per bird killed and imprisonment of up to six months. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation and, in the case of criminal penalties, up to $50,000 per violation.

In addition, federal law provides for a variety of fines and penalties, the most significant of which is the Alternative Fines Act. In lieu of the express amount of the criminal fines that may be imposed under some of the statutes described above, the Alternative Fines Act provides for a fine in the amount of twice the gross economic loss suffered by third parties, which amount, although difficult to estimate, is significant.

On December 15, 2010, the DOJ filed a civil action seeking damages and injunctive relief against BP Exploration, Anadarko Petroleum Corporation and Anadarko E&P Company LP (together, Anadarko), who had an approximate 25% interest in the Macondo well, certain subsidiaries of Transocean Ltd., and others for violations of the CWA and the OPA. The DOJ's complaint seeks an action declaring that the defendants are strictly liable under the CWA as a result of harmful discharges of oil into the Gulf of Mexico and upon United States shorelines as a result of the Macondo well incident. The complaint also seeks an action declaring that the defendants are strictly liable under the OPA for the discharge of oil that has resulted in, among other things, injury to, loss of, loss of use of, or destruction of natural resources and resource services in and around the Gulf of Mexico and the adjoining United States shorelines and resulting in removal costs and damages to the United States far exceeding $75 million. BP Exploration has been designated, and has accepted the designation, as a responsible party for the pollution under the CWA and the OPA. Others have also been named as responsible parties, and all responsible parties may be held jointly and severally liable for any damages under the OPA. A responsible party may make a claim for contribution against any other responsible party or against third parties it alleges contributed to or caused the oil spill. In connection with the proceedings discussed below under "Litigation," in April 2011 BP Exploration filed a claim against us for contribution with respect to liabilities incurred by BP Exploration under the OPA or another law and requested a judgment that the DOJ assert its claims for OPA financial liability directly against us.

We have not been named as a responsible party under the CWA or the OPA in the DOJ civil action, and we do not believe we are a responsible party under the CWA or the OPA. While we are not included in the DOJ's civil complaint, there can be no assurance that the DOJ or other federal or state governmental authorities will not bring an action, whether civil or criminal, against us under the CWA, the OPA, and/or other statutes or regulations. In connection with the DOJ's filing of the civil action, it announced that its criminal and civil investigations are continuing and that it will employ efforts to hold accountable those who are responsible for the incident.

A federal grand jury has been convened in Louisiana to investigate potential criminal conduct in connection with the Macondo well incident. We are cooperating fully with the DOJ's criminal investigation. As of February 16, 2012, the DOJ has not commenced any criminal proceedings against us. We cannot predict the status or outcome of the DOJ's criminal investigation or estimate the potential impact the investigation may have on us or our liability assessment, all of which may change as the investigation progresses.

In June 2010, we received a letter from the DOJ requesting thirty days advance notice of any event that may involve substantial transfers of cash or other corporate assets outside of the ordinary course of business. We conveyed our interest in briefing the DOJ on the services we provided on the Deepwater Horizon but indicated that we would not bind ourselves to the DOJ request.

We have had and expect to continue to have discussions with the DOJ regarding the Macondo well incident and associated pre-incident and post-incident conduct.

Investigative Reports. On September 8, 2010, an incident investigation team assembled by BP issued the Deepwater Horizon Accident Investigation Report (BP Report). The BP Report outlined eight key findings of BP related to the possible causes of the Macondo well incident, including failures of cement barriers, failures of equipment provided by other service companies and the drilling contractor, and failures of judgment by BP and the drilling contractor. With respect to the BP Report's assessment that the cement barrier did not prevent hydrocarbons from entering the wellbore after cement placement, the BP Report concluded that, among other things, there were "weaknesses in cement design and testing." According to the BP Report, the BP incident investigation team did not review its analyses or conclusions with us or any other entity or governmental agency conducting a separate or independent investigation of the incident. In addition, the BP incident investigation team did not conduct any testing using our cementing products.

On June 22, 2011, Transocean released its internal investigation report on the causes of the Macondo well incident. Transocean's report, among other things, alleges deficiencies with our cementing services on the Deepwater Horizon. Like the BP Report, the Transocean incident investigation team did not review its analyses or conclusions with us and did not conduct any testing using our cementing products.

On January 11, 2011, the National Commission released "Deep Water -- The Gulf Oil Disaster and the Future of Offshore Drilling," its investigation report (Investigation Report) to the President of the United States regarding, among other things, the National Commission's conclusions of the causes of the Macondo well incident. According to the Investigation Report, the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report stated that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report, however, acknowledges a fact widely accepted by the industry that cementing wells is a complex endeavor utilizing an inherently uncertain process in which failures are not uncommon and that, as a result, the industry utilizes the negative-pressure test and cement bond log test, among others, to identify cementing failures that require remediation before further work on a well is performed.

The Investigation Report also sets forth the National Commission's findings on certain missteps, oversights and other factors that may have caused, or contributed to the cause of, the incident, including BP's decision to use a long string casing instead of a liner casing, BP's decision to use only six centralizers, BP's failure to run a cement bond log, BP's reliance on the primary cement job as a barrier to a possible blowout, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, BP's temporary abandonment procedures, and the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, gas, or fluid into the well (known as a "kick") was occurring. With respect to the National Commission's finding that our surface data logging specialist failed to recognize a kick, the Investigation Report acknowledged that there were simultaneous activities and other monitoring responsibilities that may have prevented the surface data logging specialist from recognizing a kick.

The Investigation Report also identified two general root causes of the Macondo well incident: systemic failures by industry management, which the National Commission labeled “the most significant failure at Macondo,” and failures in governmental and regulatory oversight. The National Commission cited examples of failures by industry management such as BP’s lack of controls to adequately identify or address risks arising from changes to well design and procedures, the failure of BP’s and our processes for cement testing, communication failures among BP, Transocean, and us, including with respect to the difficulty of our cement job, Transocean’s failure to adequately communicate lessons from a recent near-blowout, and the lack of processes to adequately assess the risk of decisions in relation to the time and cost those decisions would save. With respect to failures of governmental and regulatory oversight, the National Commission concluded that applicable drilling regulations were inadequate, in part because of a lack of resources and political support of the MMS, and a lack of expertise and training of MMS personnel to enforce regulations that were in effect.

As a result of the factual and technical complexity of the Macondo well incident, the Chief Counsel of the National Commission issued a separate, more detailed report regarding the technical, managerial, and regulatory causes of the Macondo well incident in February 2011.

In March 2011, a third party retained by the BOEMRE to undertake a forensic examination and evaluation of the blowout preventer stack, its components and associated equipment, released a report detailing its findings. The forensic examination report found, among other things, that the blowout preventer stack failed primarily because the blind sheer rams did not fully close and seal the well due to a portion of drill pipe that had become trapped between the blocks and the pipe being outside the cutting surface of the ram blades. The forensic examination report recommended further examination, investigation, and testing, which found that the redundant operating pods of the blowout preventer may not have timely functioned the blind shear rams in the automatic mode function due to a depleted battery in one pod and a miswired solenoid in the other pod. We had no part in manufacturing or servicing the blowout preventer stack.

In September 2011, the BOEMRE released the final report of the Marine Board Investigation regarding the Macondo well incident (BOEMRE Report). A panel of investigators of the BOEMRE identified a number of causes of the Macondo well incident. According to the BOEMRE Report, “a central cause of the blowout was failure of a cement barrier in the production casing string.” The panel was unable to identify the precise reasons for the failure but concluded that it was likely due to: “(1) swapping of cement and drilling mud in the shoe track (the section of casing near the bottom of the well); (2) contamination of the shoe track cement; or (3) pumping the cement past the target location in the well, leaving the shoe track with little or no cement.” Generally, the panel concluded that the Macondo well incident was the result of, among other things, poor risk management, last-minute changes to drilling plans, failure to observe and respond to critical indicators, and inadequate well control response by the companies and individuals involved. In particular, the BOEMRE Report stated that BP made a series of decisions that complicated the cement job and may have contributed to the failure of the cement job, including the use of only one cement barrier, the location of the production casing, and the failure to follow industry-accepted recommendations.

The BOEMRE Report also stated, among other things, that BP failed to properly communicate well design and cementing decisions and risks to Transocean, that BP and Transocean failed to correctly interpret the negative-pressure test, and that we, BP, and Transocean failed to detect the influx of hydrocarbons into the well. According to the BOEMRE Report, the panel found evidence that we, among others, violated federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the well under control, and the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico. In October 2011, the BSEE issued a notification of Incidents of Noncompliance (INCs) to us for violating those regulations and a federal regulation relating to the failure to protect health, safety, property, and the environment as a result of a failure to perform operations in a safe and workmanlike manner. According to the BSEE's notice, we did not ensure an adequate barrier to hydrocarbon flow after cementing the production casing and did not detect the influx of hydrocarbons until they were above the blowout preventer stack. We understand that the regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation. We have appealed the INCs to, and the appeal was accepted by, the Interior Board of Land Appeals (IBLA). In January 2012, the IBLA, in response to our and the BSEE's joint request, has suspended the appeal and has ordered us and the BSEE to file notice within 15 days after the conclusion of the MDL and, within 60 days after the MDL court issues a final decision, to file a proposal for further action in the appeal. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal has ended. The BSEE has stated that this is the first time the Department of the Interior has issued INCs directly to a contractor that was not the well's operator. We have not accrued any amounts related to the INCs.

In December 2011, the National Academy of Sciences released a pre-publication copy of its report examining the causes of the Macondo well incident and identifying measures for preventing similar incidents in the future (NAS Report). The NAS Report noted that it does not attempt to assign responsibility to specific individuals or entities or determine the extent that the parties involved complied with applicable regulations.

According to the NAS Report, the flow of hydrocarbons that led to the blowout began when drilling mud was displaced by seawater during the temporary abandonment process, which was commenced by the drilling team despite a failure to demonstrate the integrity of the cement job after multiple negative pressure tests and after incorrectly deciding that a negative pressure test indicated that the cement barriers were effective. In addition, the NAS Report found, among other things, that: the approach chosen for well completion failed to provide adequate safety margins considering the reservoir formation; the loss of well control was not noted until more than 50 minutes after hydrocarbon flow from the formation had started; the blowout preventer was not designed or tested for the dynamic conditions that most likely existed at the time attempts were made to recapture well control; and the entities involved did not provide an effective systems safety approach commensurate with the risks of the Macondo well. According to the NAS Report, a number of key decisions related to the design, construction, and testing of the barriers critical to the temporary abandonment process were flawed.

The NAS Report also found, among other things, that the heavier "tail" cement slurry, intended for placement in the Macondo well shoe track, was "gravitationally unstable" on top of the lighter foam cement slurry and that the heavier tail cement slurry probably fell into or perhaps through the lighter foam cement slurry during pumping into the well, which would have left a tail slurry containing foam cement in the shoe track. The NAS Report also found, among other things, that foam cement that may have been inadvertently left in the shoe track likely would not have had the strength to resist crushing when experiencing the differential pressures exerted on the cement during the negative pressure test. In addition, the NAS Report found, among other things, that evidence available before the blowout indicated that the flapper valves in the float collar probably failed to seal, but the evidence was not acted upon and, due to BP's choice of a long-string production casing and the lack of minimum circulation of the well prior to the cement job, the possibility of mud-filled channels or poor cement bonding existed.

The NAS Report also set forth the following observations, among others: (1) there were alternative completion techniques and operational processes available that could have safely prepared the well for temporary abandonment; (2) post-incident static tests on a foam cement slurry similar to the slurry pumped into the Macondo well were performed under laboratory conditions and exhibited the settling of cement and nitrogen breakout, although because the tests were not conducted at bottom hole conditions "it is impossible to say whether the foam was stable at the bottom of the well"; (3) the "cap" cement slurry was subject to contamination by the spacer or the drilling mud that was placed ahead of the cap cement slurry and, if the cap cement slurry was heavily contaminated, it would not reach the strength of uncontaminated cement; (4) the numerous companies involved and the division of technical expertise among those companies affected their ability to perform and maintain an integrated assessment of the margins of safety for the Macondo well; (5) the regulatory regime was ineffective in addressing the risks of the Macondo well; and (6) training of key personnel and decision makers in the industry and regulatory agencies has been inadequate relative to the risks and complexities of deepwater drilling.

The NAS Report recommended, among other things: that all primary cemented barriers to flow should be tested to verify quality, quantity, and location of cement; that the integrity of mechanical barriers should be verified by using the best available test procedures; that blowout preventer systems should be redesigned for the drilling environment to which they are being applied; and that operating companies should have ultimate responsibility and accountability for well integrity, well design, well construction, and the suitability of the rig and associated safety equipment.

The Cementing Job and Reaction to Reports. We disagree with the BP Report, the National Commission, Transocean's report, the BOEMRE Report, and the NAS Report regarding many of their findings and characterizations with respect to the cementing and surface data logging services, as applicable, on the Deepwater Horizon. We have provided information to the National Commission, its staff, and representatives of the joint investigation team for the Marine Board Investigation that we believe has been overlooked or selectively omitted from the Investigation Report and the BOEMRE Report, as applicable. We intend to continue to vigorously defend ourselves in any investigation relating to our involvement with the Macondo well that we believe inaccurately evaluates or depicts our services on the Deepwater Horizon.

The cement slurry on the Deepwater Horizon was designed and prepared pursuant to well condition data provided by BP. Regardless of whether alleged weaknesses in cement design and testing are or are not ultimately established, and regardless of whether the cement slurry was utilized in similar applications or was prepared consistent with industry standards, we believe that had BP and Transocean properly interpreted a negative-pressure test, this test would have revealed any problems with the cement. In addition, had BP designed the Macondo well to allow a full cement bond log test or if BP had conducted even a partial cement bond log test, the test likely would have revealed any problems with the cement. BP, however, elected not to conduct any cement bond log tests, and with Transocean misinterpreted the negative-pressure test, both of which could have resulted in remedial action, if appropriate, with respect to the cementing services.

At this time we cannot predict the impact of the Investigation Report, the BOEMRE Report, the NAS Report, or the conclusions of future reports of the Chemical Safety Board, Congressional committees, or any other governmental or private entity. We also cannot predict whether their investigations or any other report or investigation will have an influence on or result in us being named as a party in any action alleging liability or violation of a statute or regulation, whether federal or state and whether criminal or civil.

We intend to continue to cooperate fully with all governmental hearings, investigations, and requests for information relating to the Macondo well incident. We cannot predict the outcome of, or the costs to be incurred in connection with, any of these hearings or investigations, and therefore we cannot predict the potential impact they may have on us.

Litigation. Since April 21, 2010, plaintiffs have been filing lawsuits relating to the Macondo well incident. Generally, those lawsuits allege either (1) damages arising from the oil spill pollution and contamination (*e.g.*, diminution of property value, lost tax revenue, lost business revenue, lost tourist dollars, inability to engage in recreational or commercial activities) or (2) wrongful death or personal injuries. We are named along with other unaffiliated defendants in more than 400 complaints, most of which are alleged class actions, involving pollution damage claims and at least nine personal injury lawsuits involving four decedents and at least 21 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Plaintiffs originally filed the lawsuits described above in federal and state courts throughout the United States, including Alabama, Delaware, Florida, Georgia, Kentucky, Louisiana, Mississippi, South Carolina, Tennessee, Texas, and Virginia. Except for certain lawsuits not yet consolidated (including two lawsuits that are proceeding in Louisiana state court, one lawsuit that is proceeding in Louisiana federal court, two lawsuits that are proceeding in Texas state court, two lawsuits that are proceeding in Florida federal court, and four lawsuits in Florida state court for which we have not been served), the Judicial Panel on Multi-District Litigation ordered all of the lawsuits against us consolidated in the MDL proceeding before Judge Carl Barbier in the United States Eastern District of Louisiana. The pollution complaints generally allege, among other things, negligence and gross negligence, property damages, taking of protected species, and potential economic losses as a result of environmental pollution and generally seek awards of unspecified economic, compensatory, and punitive damages, as well as injunctive relief. Plaintiffs in these pollution cases have brought suit under various legal provisions, including the OPA, the CWA, the MBTA, the ESA, the OCSLA, the Longshoremen and Harbor Workers Compensation Act, general maritime law, state common law, and various state environmental and products liability statutes.

Furthermore, the pollution complaints include suits brought against us by governmental entities, including the State of Alabama, the State of Louisiana, Plaquemines Parish, the City of Greenville, and three Mexican states. Complaints brought against us by ten other parishes in Louisiana were dismissed with prejudice, and the dismissal is being appealed by those parishes. The wrongful death and other personal injury complaints generally allege negligence and gross negligence and seek awards of compensatory damages, including unspecified economic damages and punitive damages. We have retained counsel and are investigating and evaluating the claims, the theories of recovery, damages asserted, and our respective defenses to all of these claims.

Judge Barbier is also presiding over a separate proceeding filed by Transocean under the Limitation of Liability Act (Limitation Action). In the Limitation Action, Transocean seeks to limit its liability for claims arising out of the Macondo well incident to the value of the rig and its freight. Although the Limitation Action is not consolidated in the MDL, to this point the judge is effectively treating the two proceedings as associated cases. On February 18, 2011, Transocean tendered us, along with all other defendants, into the Limitation Action. As a result of the tender, we and all other defendants will be treated as direct defendants to the plaintiffs' claims as if the plaintiffs had sued each of us and the other defendants directly. In the Limitation Action, the judge intends to determine the allocation of liability among all defendants in the hundreds of lawsuits associated with the Macondo well incident, including those in the MDL proceeding that are pending in his court. Specifically, the judge will determine the liability, limitation, exoneration and fault allocation with regard to all of the defendants in a trial, which is scheduled to occur in three phases, that is set to begin in late February 2012. The three phases of this portion of the trial are scheduled to cover the liabilities associated with the blowout itself, the actions relating to the attempts to control the flow of hydrocarbons from the well, and the efforts to contain and clean-up the oil that was discharged from the Macondo well. We do not believe that a single apportionment of liability in the Limitation Action is properly applied, particularly with respect to gross negligence and punitive damages, to the hundreds of lawsuits pending in the MDL proceeding.

Damages for the cases tried in the MDL proceeding, including punitive damages, are expected to be tried following the three-phase portion of the trial described above. Under ordinary MDL procedures, such cases would, unless waived by the respective parties, be tried in the courts from which they were transferred into the MDL. It remains unclear, however, what impact the overlay of the Limitation Action will have on where these matters are tried. Document discovery and depositions among the parties to the MDL are ongoing. It is unclear how the judge will address the DOJ's civil action for alleged violations of the CWA and the OPA.

In April and May 2011, certain defendants in the proceedings described above filed numerous cross claims and third party claims against certain other defendants. BP Exploration and BP America Production Company filed claims against us seeking subrogation and contribution, including with respect to liabilities under the OPA, and direct damages, and alleging negligence, gross negligence, fraudulent conduct, and fraudulent concealment. Transocean filed claims against us seeking indemnification, and subrogation and contribution, including with respect to liabilities under the OPA and for the total loss of the Deepwater Horizon, and alleging comparative fault and breach of warranty of workmanlike performance. Anadarko filed claims against us seeking tort indemnity and contribution, and alleging negligence, gross negligence and willful misconduct, and MOEX Offshore 2007 LLC (MOEX), who has an approximate 10% interest in the Macondo well, filed a claim against us alleging negligence. Cameron International Corporation (Cameron) (the manufacturer and designer of the blowout preventer), M-I Swaco (provider of drilling fluids and services, among other things), Weatherford U.S. L.P. and Weatherford International, Inc. (together, Weatherford) (providers of casing components, including float equipment and centralizers, and services), and Dril-Quip, Inc. (Dril-Quip) (provider of wellhead systems), each filed claims against us seeking indemnification and contribution, including with respect to liabilities under the OPA in the case of Cameron, and alleging negligence. Additional civil lawsuits may be filed against us. In addition to the claims against us, generally the defendants in the proceedings described above filed claims, including for liabilities under the OPA and other claims similar to those described above, against the other defendants described above. BP has since announced that it has settled those claims between it and each of MOEX, Weatherford, Anadarko, and Cameron.

In April 2011, we filed claims against BP Exploration, BP p.l.c. and BP America Production Company (BP Defendants), M-I Swaco, Cameron, Anadarko, MOEX, Weatherford, Dril-Quip, and numerous entities involved in the post-blowout remediation and response efforts, in each case seeking contribution and indemnification and alleging negligence. Our claims also alleged gross negligence and willful misconduct on the part of the BP Defendants, Anadarko, and Weatherford. We also filed claims against M-I Swaco and Weatherford for contractual indemnification, and against Cameron, Weatherford and Dril-Quip for strict products liability, although the court has since issued orders dismissing all claims asserted against Dril-Quip and Weatherford in the MDL. We filed our answer to Transocean's Limitation petition denying Transocean's right to limit its liability, denying all claims and responsibility for the incident, seeking contribution and indemnification, and alleging negligence and gross negligence.

Judge Barbier has issued an order, among others, clarifying certain aspects of law applicable to the lawsuits pending in his court. The court ruled that: (1) general maritime law will apply and therefore dismissed all claims brought under state law causes of action; (2) general maritime law claims may be brought directly against defendants who are non-"responsible parties" under the OPA with the exception of pure economic loss claims by plaintiffs other than commercial fishermen; (3) all claims for damages, including pure economic loss claims, may be brought under the OPA directly against responsible parties; and (4) punitive damage claims can be brought against both non-responsible parties under general maritime law and responsible parties under the OPA. As discussed above, with respect to the ruling that claims for damages may be brought under the OPA against responsible parties, we have not been named as a responsible party under the OPA, but BP Exploration has filed a claim against us for contribution with respect to liabilities incurred by BP Exploration under the OPA.

In September 2011, we filed claims in Harris County, Texas against the BP Defendants seeking damages, including lost profits and exemplary damages, and alleging negligence, grossly negligent misrepresentation, defamation, common law libel, slander, and business disparagement. Our claims allege that the BP Defendants knew or should have known about an additional hydrocarbon zone in the well that the BP Defendants failed to disclose to us prior to our designing the cement program for the Macondo well. The location of the hydrocarbon zones is critical information required prior to performing cementing services and is necessary to achieve desired cement placement. We believe that had BP Defendants disclosed the hydrocarbon zone to us, we would not have proceeded with the cement program unless it was redesigned, which likely would have required a redesign of the production casing. In addition, we believe that the BP Defendants withheld this information from the BP Report and from the various investigations discussed above. In connection with the foregoing, we also moved to amend our claims against the BP Defendants in the MDL proceeding to include fraud. The BP Defendants have denied all of the allegations relating to the additional hydrocarbon zone and filed a motion to prevent us from adding our fraud claim in the MDL. In October 2011, our motion to add the fraud claim against the BP Defendants in the MDL proceeding was denied. The court's ruling does not, however, prevent us from using the underlying evidence in our pending claims against the BP Defendants.

In December 2011, BP filed a motion for sanctions against us alleging, among other things, that we destroyed evidence relating to post-incident testing of the foam cement slurry on the Deepwater Horizon and requesting adverse findings against us. A magistrate judge in the MDL proceeding denied BP's motion. BP appealed that ruling, and Judge Barbier affirmed the magistrate judge's decision.

We intend to vigorously defend any litigation, fines, and/or penalties relating to the Macondo well incident and to vigorously pursue any damages, remedies, or other rights available to us as a result of the Macondo well incident. We have incurred and expect to continue to incur significant legal fees and costs, some of which we expect to be covered by indemnity or insurance, as a result of the numerous investigations and lawsuits relating to the incident.

Macondo derivative case. In February 2011, a shareholder who had previously made a demand on our board of directors with respect to another derivative lawsuit filed a shareholder derivative lawsuit relating to the Macondo well incident. See "Shareholder derivative cases" below.

Indemnification and Insurance. Our contract with BP Exploration relating to the Macondo well generally provides for our indemnification by BP Exploration for certain potential claims and expenses relating to the Macondo well incident, including those resulting from pollution or contamination (other than claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment). Also, under our contract with BP Exploration, we have, among other things, generally agreed to indemnify BP Exploration and other contractors performing work on the well for claims for personal injury of our employees and subcontractors, as well as for damage to our property. In turn, we believe that BP Exploration was obligated to obtain agreement by other contractors performing work on the well to indemnify us for claims for personal injury of their employees or subcontractors, as well as for damages to their property. We have entered into separate indemnity agreements with Transocean and M-I Swaco, under which we have agreed to indemnify those parties for claims for personal injury of our employees and subcontractors and they have agreed to indemnify us for claims for personal injury of their employees and subcontractors.

In April 2011, we filed a lawsuit against BP Exploration in Harris County, Texas to enforce BP Exploration's contractual indemnity and alleging BP Exploration breached certain terms of the contractual indemnity provision. BP Exploration removed that lawsuit to federal court in the Southern District of Texas, Houston Division. We filed a motion to remand the case to Harris County, Texas, and the lawsuit was transferred to the MDL.

BP Exploration, in connection with filing its claims with respect to the MDL proceeding, asked that court to declare that it is not liable to us in contribution, indemnification, or otherwise with respect to liabilities arising from the Macondo well incident. Other defendants in the litigation discussed above have generally denied any obligation to contribute to any liabilities arising from the Macondo well incident.

In January 2012, the court in the MDL proceeding entered an order in response to our and BP's motions for summary judgment regarding certain indemnification matters. The court held that BP is required to indemnify us for third-party compensatory claims, or actual damages, that arise from pollution or contamination that did not originate from our property or equipment located above the surface of the land or water, even if we are found to be grossly negligent. The court did not express an opinion as to whether our conduct amounted to gross negligence, but we do not believe the performance of our services on the Deepwater Horizon constituted gross negligence. The court also held, however, that BP does not owe us indemnity for punitive damages or for civil penalties under the CWA, if any, and that fraud could void the indemnity on public policy grounds, although the court stated that it was mindful that mere failure to perform contractual obligations as promised does not constitute fraud. As discussed above, the DOJ is not seeking civil penalties from us under the CWA. The court in the MDL proceeding deferred ruling on whether our indemnification from BP covers penalties or fines under the OCSLA, whether our alleged breach of our contract with BP Exploration would invalidate the indemnity, and whether we committed an act that materially increased the risk to or prejudiced the rights of BP so as to invalidate the indemnity. We do not believe that we breached our contract with BP Exploration or committed an act that would otherwise invalidate the indemnity. The court's rulings will be subject to appeal at the appropriate time.

In responding to similar motions for summary judgment between Transocean and BP, the court also held that public policy would not bar Transocean's claim for indemnification of compensatory damages, even if Transocean was found to be grossly negligent. The court also held, among other things, that Transocean's contractual right to indemnity does not extend to punitive damages or civil penalties under the CWA.

The rulings in the MDL proceeding regarding the indemnities are based on maritime law and may not bind the determination of similar issues in lawsuits not comprising a part of the MDL proceedings. Accordingly it is possible that different conclusions with respect to indemnities will be reached by other courts.

Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. In addition, certain state laws, if deemed to apply, would not allow for enforcement of indemnification for gross negligence, and may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims.

Financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. BP's public filings indicate that BP has recognized in excess of $40 billion in pre-tax charges, excluding offsets for settlement payments received from certain defendants in the proceedings described above under "Litigation," as a result of the Macondo well incident. BP's public filings also indicate that the amount of, among other things, certain natural resource damages with respect to certain OPA claims, some of which may be included in such charges, cannot be reliably estimated as of the dates of those filings. We consider, however, the likelihood of a BP bankruptcy to be remote.

In addition to the contractual indemnities discussed above, we have a general liability insurance program of $600 million. Our insurance is designed to cover claims by businesses and individuals made against us in the event of property damage, injury or death and, among other things, claims relating to environmental damage, as well as legal fees incurred in defending against those claims. We have received and expect to continue to receive payments from our insurers with respect to covered legal fees incurred in connection with the Macondo well incident. Through January 2012, we have incurred legal fees and related expenses covered by our insurance program of approximately $76 million. To the extent we incur any losses beyond those covered by indemnification, there can be no assurance that our insurance policies will cover all potential claims and expenses relating to the Macondo well incident. In addition, we may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies. Insurance coverage can be the subject of uncertainties and, particularly in the event of large claims, potential disputes with insurance carriers, as well as other potential parties claiming insured status under our insurance policies.

Barracuda-Caratinga arbitration

We provided indemnification in favor of KBR under the master separation agreement for all out-of-pocket cash costs and expenses (except for legal fees and other expenses of the arbitration so long as KBR controls and directs it), or cash settlements or cash arbitration awards, KBR may incur after November 20, 2006 as a result of the replacement of certain subsea flowline bolts installed in connection with the Barracuda-Caratinga project. At Petrobras' direction, KBR replaced certain bolts located on the subsea flowlines that failed through mid-November 2005, and KBR informed us that additional bolts have failed thereafter, which were replaced by Petrobras. These failed bolts were identified by Petrobras when it conducted inspections of the bolts. In March 2006, Petrobras commenced arbitration against KBR claiming $220 million plus interest for the cost of monitoring and replacing the defective bolts and all related costs and expenses of the arbitration, including the cost of attorneys' fees. The arbitration panel held an evidentiary hearing in March 2008 to determine which party was responsible for the designation of the material used for the bolts. On May 13, 2009, the arbitration panel held that KBR and not Petrobras selected the material to be used for the bolts. Accordingly, the arbitration panel held that there is no implied warranty by Petrobras to KBR as to the suitability of the bolt material and that the parties' rights are to be governed by the express terms of their contract. The parties presented evidence and witnesses to the panel in May 2010, and final arguments were presented in August 2010. During the third quarter of 2011, the arbitration panel issued an award against KBR in the amount of $201 million, which is reflected as a liability and a component of loss from discontinued operations in our consolidated financial statements. KBR filed a motion to vacate the arbitration award with the United States District Court for the Southern District of New York. See Note 7 for additional information regarding the KBR indemnification.

Securities and related litigation

In June 2002, a class action lawsuit was filed against us in federal court alleging violations of the federal securities laws after the Securities and Exchange Commission (SEC) initiated an investigation in connection with our change in accounting for revenue on long-term construction projects and related disclosures. In the weeks that followed, approximately twenty similar class actions were filed against us. Several of those lawsuits also named as defendants several of our present or former officers and directors. The class action cases were later consolidated, and the amended consolidated class action complaint, styled *Richard Moore, et al. v. Halliburton Company, et al.*, was filed and served upon us in April 2003. As a result of a substitution of lead plaintiffs, the case was styled *Archdiocese of Milwaukee Supporting Fund (AMSF) v. Halliburton Company, et al*. AMSF has changed its name to Erica P. John Fund, Inc. (the Fund). We settled with the SEC in the second quarter of 2004.

In June 2003, the lead plaintiffs filed a motion for leave to file a second amended consolidated complaint, which was granted by the court. In addition to restating the original accounting and disclosure claims, the second amended consolidated complaint included claims arising out of our 1998 acquisition of Dresser Industries, Inc., including that we failed to timely disclose the resulting asbestos liability exposure.

In April 2005, the court appointed new co-lead counsel and named the Fund the new lead plaintiff, directing that it file a third consolidated amended complaint and that we file our motion to dismiss. The court held oral arguments on that motion in August 2005. In March 2006, the court entered an order in which it granted the motion to dismiss with respect to claims arising prior to June 1999 and granted the motion with respect to certain other claims while permitting the Fund to re-plead some of those claims to correct deficiencies in its earlier complaint. In April 2006, the Fund filed its fourth amended consolidated complaint. We filed a motion to dismiss those portions of the complaint that had been re-pled. A hearing was held on that motion in July 2006, and in March 2007 the court ordered dismissal of the claims against all individual defendants other than our Chief Executive Officer (CEO). The court ordered that the case proceed against our CEO and us.

In September 2007, the Fund filed a motion for class certification, and our response was filed in November 2007. The district court held a hearing in March 2008, and issued an order November 3, 2008 denying the motion for class certification. The Fund appealed the district court's order to the Fifth Circuit Court of Appeals. The Fifth Circuit affirmed the district court's order denying class certification. On May 13, 2010, the Fund filed a writ of certiorari in the United States Supreme Court. In early January 2011, the Supreme Court granted the writ of certiorari and accepted the appeal. The Court heard oral arguments in April 2011 and issued its decision in June 2011, reversing the Fifth Circuit ruling that the Fund needed to prove loss causation in order to obtain class certification. The Court's ruling was limited to the Fifth Circuit's loss causation requirement, and the case was returned to the Fifth Circuit for further consideration of our other arguments for denying class certification. The Fifth Circuit returned the case to the district court, and in January 2012 the court issued an order certifying the class which we have appealed. The case is at an early stage, and we cannot predict the outcome or consequences thereof. As of December 31, 2011, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. Further, an estimate of possible loss or range of loss related to this matter cannot be made. We intend to vigorously defend this case.

Shareholder derivative cases

In May 2009, two shareholder derivative lawsuits involving us and KBR were filed in Harris County, Texas, naming as defendants various current and retired Halliburton directors and officers and current KBR directors. These cases allege that the individual Halliburton defendants violated their fiduciary duties of good faith and loyalty, to our detriment and the detriment of our shareholders, by failing to properly exercise oversight responsibilities and establish adequate internal controls. The District Court consolidated the two cases, and the plaintiffs filed a consolidated petition against only current and former Halliburton directors and officers containing various allegations of wrongdoing including violations of the FCPA, claimed KBR offenses while acting as a government contractor in Iraq, claimed KBR offenses and fraud under United States government contracts, Halliburton activity in Iran, and illegal kickbacks. Subsequently, a shareholder made a demand that the board take remedial action respecting the FCPA claims in the pending lawsuit. Our Board of Directors designated a special committee of independent and disinterested directors to oversee the investigation of the allegations made in the lawsuits and shareholder demand. Upon receipt of its special committee's findings and recommendations, the independent and disinterested members of the Board determined that the shareholder claims were without merit and not otherwise in the best interest of the company to pursue. The Board directed company counsel to report its determinations to the plaintiffs and demanding shareholder. As of December 31, 2011, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. Further, an estimate of possible loss or range of loss related to this matter cannot be made.

We have agreed in principle, subject to approval by the court, to settle the lawsuits. Under the terms of the proposed settlement, we have agreed to implement certain changes to our corporate governance policies and agreed to pay the plaintiffs' legal fees.

In February 2011, the same shareholder who had made the demand on our board of directors in connection with one of the derivative lawsuits discussed above filed a shareholder derivative lawsuit in Harris County, Texas naming us as a nominal defendant and certain of our directors and officers as defendants. This case alleges that these defendants, among other things, breached fiduciary duties of good faith and loyalty by failing to properly exercise oversight responsibilities and establish adequate internal controls, including controls and procedures related to cement testing and the communication of test results, as they relate to the Macondo well incident. Our Board of Directors designated a special committee of independent and disinterested directors to oversee the investigation of the allegations made in the lawsuit and shareholder demand. Upon receipt of its special committee's findings and recommendations, the independent and disinterested members of the Board determined that the shareholder claims were without merit and not otherwise in the best interest of the company to pursue. The Board directed company counsel to report its determinations to the plaintiffs and demanding shareholder. As of December 31, 2011, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. Further, an estimate of possible loss or range of loss related to this matter cannot be made.

Angola Investigations

We are conducting an internal investigation of certain areas of our operations in Angola, focusing on compliance with certain company policies, including our Code of Business Conduct (COBC), and the FCPA and other applicable laws. In December 2010, we received an anonymous e-mail alleging that certain current and former personnel violated our COBC and the FCPA, principally through the use of an Angolan vendor. The e-mail also alleges conflicts of interest, self-dealing and the failure to act on alleged violations of our COBC and the FCPA. We contacted the DOJ to advise them that we were initiating an internal investigation with the assistance of outside counsel and independent forensic accountants.

During the third quarter of 2011, we met with the DOJ and the SEC to brief them on the status of our investigation and provided them documents. We are currently responding to a subpoena from the SEC regarding this matter and are producing all relevant documents. We understand that one of our employees has also received a subpoena from the SEC regarding this matter.

We expect to continue to have discussions with the DOJ and the SEC, and we intend to continue to cooperate with their inquiries and requests as they investigate this matter. Because these investigations are at an early stage, we cannot predict their outcome or the consequences thereof.

Environmental

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. In the United States, these laws and regulations include, among others:

- the Comprehensive Environmental Response, Compensation, and Liability Act;
- the Resource Conservation and Recovery Act;
- the Clean Air Act;
- the Federal Water Pollution Control Act;
- the Toxic Substances Control Act; and
- the Oil Pollution Act of 1990.

In addition to the federal laws and regulations, states and other countries where we do business often have numerous environmental, legal, and regulatory requirements by which we must abide. We evaluate and address the environmental impact of our operations by assessing and remediating contaminated properties in order to avoid future liabilities and comply with environmental, legal, and regulatory requirements. Our Health, Safety and Environment group has several programs in place to maintain environmental leadership and to help prevent the occurrence of environmental contamination. On occasion, in addition to the matters relating to the Macondo well incident described above and the Duncan, Oklahoma matter described below, we are involved in other environmental litigation and claims, including the remediation of properties we own or have operated, as well as efforts to meet or correct compliance-related matters. We do not expect costs related to those remediation requirements to have a material adverse effect on our consolidated financial position or our results of operations. Our accrued liabilities for environmental matters were $81 million as of December 31, 2011 and $47 million as of December 31, 2010. Our total liability related to environmental matters covers numerous properties.

Between 1965 and 1991, a former Halliburton unit known as the Halliburton Industrial Services Division (HISD) performed work for the U.S. Department of Defense cleaning solid fuel from missile casings at a semi-rural facility on the north side of Duncan, Oklahoma. We closed our site in coordination with the Oklahoma Department of Environmental Quality (DEQ) in the mid-1990s, but continued to monitor the groundwater at DEQ's request. A principal component of the missile fuel was ammonium perchlorate, a salt that is highly soluble in water, which has been discovered in the soil and groundwater on our site and in certain residential water wells near our property.

Commencing in October 2011, a number of lawsuits were filed against us, including a putative class action case in federal court in the Western District of Oklahoma and other lawsuits filed in Oklahoma state courts. The lawsuits generally allege, among other things, that operations at our Duncan facility caused releases of pollutants, including ammonium perchlorate and, in the case of the federal lawsuit, nuclear or radioactive waste, into the groundwater, and that we knew about those releases and did not take corrective actions to address them. It is also alleged that the plaintiffs have suffered from certain health conditions, including hypothyroidism, a condition that has been associated with exposure to perchlorate at sufficiently high doses over time. These cases seek, among other things, damages, including punitive damages, and the establishment of a fund for future medical monitoring. The cases allege, among other things, strict liability, trespass, private nuisance, public nuisance, and negligence and, in the case of the federal lawsuit, violations of the U.S. Resource Conservation and Recovery Act, resulting in personal injuries, property damage, and diminution of property value.

The lawsuits generally allege that the cleaning of the missile casings at the Duncan facility contaminated the surrounding soils and groundwater, including certain water wells used in a number of residential homes, through the migration of, among other things, ammonium perchlorate. The federal lawsuit also alleges that our processing of radioactive waste from a nuclear power plant over 25 years ago resulted in the release of "nuclear/radioactive" waste into the environment.

We and the DEQ have recently conducted soil and groundwater sampling relating to the allegations discussed above that has confirmed that the alleged nuclear or radioactive material is confined to the soil in a discrete area of the onsite operations and is not present in the groundwater onsite or in any areas offsite. The radiological impacts from this discrete area are not believed to present any health risk for offsite exposure. With respect to ammonium perchlorate, we have made arrangements to supply affected residents with bottled drinking water and, if needed, with a temporary water supply system, at no cost to the residents. We have worked with the City of Duncan and the DEQ to expedite expansion of the city water supply to the relevant areas.

The lawsuits described above are at an early stage, and additional lawsuits and proceedings may be brought against us. We cannot predict their outcome or the consequences thereof. As of December 31, 2011, we had accrued $35 million related to our initial estimate of response efforts, third-party property damage, and remediation related to the Duncan, Oklahoma matter. We intend to vigorously defend the lawsuits and do not believe that these lawsuits will have a material adverse effect on our liquidity, consolidated results of operations, or consolidated financial condition.

Additionally, we have subsidiaries that have been named as potentially responsible parties along with other third parties for nine federal and state superfund sites for which we have established reserves. As of December 31, 2011, those nine sites accounted for approximately $7 million of our $81 million total environmental reserve. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. Despite attempts to resolve these superfund matters, the relevant regulatory agency may at any time bring suit against us for amounts in excess of the amount accrued. With respect to some superfund sites, we have been named a potentially responsible party by a regulatory agency; however, in each of those cases, we do not believe we have any material liability. We also could be subject to third-party claims with respect to environmental matters for which we have been named as a potentially responsible party.

Guarantee arrangements

In the normal course of business, we have agreements with financial institutions under which approximately $1.7 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2011, including $292 million of surety bonds related to Venezuela. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Leases

We are obligated under operating leases, principally for the use of land, offices, equipment, manufacturing and field facilities, and warehouses. Total rentals, net of sublease rentals, were $735 million in 2011, $591 million in 2010, and $528 million in 2009.

Future total rentals on noncancellable operating leases are as follows: $207 million in 2012; $166 million in 2013; $112 million in 2014; $87 million in 2015; $64 million in 2016; and $164 million thereafter.

Note 9. Income Taxes

The components of the (provision)/benefit for income taxes on continuing operations were:

	Year Ended December 31		
Millions of dollars	2011	2010	2009
Current income taxes:			
Federal	$ (1,026)	$ (400)	$ 30
Foreign	(334)	(287)	(250)
State	(109)	(42)	(24)
Total current	(1,469)	(729)	(244)
Deferred income taxes:			
Federal	(28)	(124)	(237)
Foreign	57	3	(31)
State	1	(3)	(6)
Total deferred	30	(124)	(274)
Provision for income taxes	$ (1,439)	$ (853)	$ (518)

The United States and foreign components of income from continuing operations before income taxes were as follows:

	Year Ended December 31		
Millions of dollars	2011	2010	2009
United States	$ 4,040	$ 1,918	$ 589
Foreign	409	737	1,093
Total	$ 4,449	$ 2,655	$ 1,682

Reconciliations between the actual provision for income taxes on continuing operations and that computed by applying the United States statutory rate to income from continuing operations before income taxes were as follows:

	Year Ended December 31		
	2011	2010	2009
United States statutory rate	35.0%	35.0%	35.0%
Domestic manufacturing deduction	(2.1)	(1.8)	–
Adjustments of prior year taxes	(1.3)	(1.2)	(2.1)
Impact of foreign income taxed at different rates	(0.5)	(1.3)	(3.3)
Other impact of foreign operations	(0.4)	(1.3)	(0.4)
Impact of devaluation of Venezuelan Bolívar Fuerte	–	0.8	–
Other items, net	1.6	1.9	1.6
Total effective tax rate on continuing operations	32.3%	32.1%	30.8%

We have not provided United States income taxes and foreign withholding taxes on the undistributed earnings of foreign subsidiaries as of December 31, 2011 because we intend to permanently reinvest such earnings outside the United States. If these foreign earnings were to be repatriated in the future, the related United States tax liability may be reduced by any foreign income taxes previously paid on these earnings. As of December 31, 2011, the cumulative amount of earnings upon which United States income taxes have not been provided is approximately $4.1 billion. It is not possible to estimate the amount of unrecognized deferred tax liability related to these earnings at this time.

The primary components of our deferred tax assets and liabilities were as follows:

	December 31	
Millions of dollars	2011	2010
Gross deferred tax assets:		
Employee compensation and benefits	$ 345	$ 313
Net operating loss carryforwards	139	52
Accrued liabilities	64	77
Insurance accruals	48	47
Software revenue recognition	44	50
Inventory	30	28
Capitalized research and experimentation	29	44
Other	110	106
Total gross deferred tax assets	809	717
Gross deferred tax liabilities:		
Depreciation and amortization	648	631
Joint ventures, partnerships, and unconsolidated affiliates	38	48
Other	68	57
Total gross deferred tax liabilities	754	736
Valuation allowances – net operating loss carryforwards	44	22
Net deferred income tax asset (liability)	$ 11	$ (41)

At December 31, 2011, we had a total of $346 million of foreign net operating loss carryforwards, of which $211 million will expire from 2012 through 2032. The balance will not expire due to indefinite expiration dates.

The following table presents a rollforward of our unrecognized tax benefits and associated interest and penalties.

Millions of dollars	Unrecognized Tax Benefits	Interest and Penalties
Balance at January 1, 2009	$ 300	$ 43
Change in prior year tax positions	(42)	(6)
Change in current year tax positions	23	2
Cash settlements with taxing authorities	(7)	(1)
Lapse of statute of limitations	(11)	(9)
Balance at December 31, 2009	$ 263	$ 29
Change in prior year tax positions	(74)	7
Change in current year tax positions	19	2
Cash settlements with taxing authorities	(28)	(5)
Lapse of statute of limitations	(3)	(1)
Balance at December 31, 2010	$ 177(a)	$ 32
Change in prior year tax positions	38	41
Change in current year tax positions	5	1
Cash settlements with taxing authorities	(12)	(3)
Lapse of statute of limitations	(3)	(2)
Balance at December 31, 2011	$ 205(a) (b)	$ 69

(a) Includes $67 million as of December 31, 2011 and $62 million as of December 31, 2010 in amounts to be settled in accordance with our Tax Sharing Agreement with KBR and foreign unrecognized tax benefits that would give rise to a United States tax credit. See Note 7 for further information. The remaining balance of $138 million as of December 31, 2011 and $115 million as of December 31, 2010, if resolved in our favor, would positively impact the effective tax rate and, therefore, be recognized as additional tax benefits in our statement of operations.

(b) Includes $42 million that could be resolved within the next 12 months.

We file income tax returns in the United States federal jurisdiction and in various states and foreign jurisdictions. In most cases, we are no longer subject to state, local, or non-United States income tax examination by tax authorities for years before 2000. Tax filings of our subsidiaries, unconsolidated affiliates, and related entities are routinely examined in the normal course of business by tax authorities. Currently, our United States federal tax filings are under review for tax years 2008 and 2009.

Note 10. Shareholders' Equity and Stock Incentive Plans

The following tables summarize our common stock and other shareholders' equity activity:

Millions of dollars	Common Shares	Paid-in Capital in Excess of Par Value	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest in Consolidated Subsidiaries	Total
	Company Shareholders' Equity						
Balance at December 31, 2008	$ 2,666	$ 484	$(5,251)	$ 10,041	$ (215)	$ 19	$ 7,744
Cash dividends paid	–	–	–	(324)	–	–	(324)
Stock plans	3	(51)	266	–	–	–	218
Common shares purchased	–	–	(17)	–	–	–	(17)
Tax loss from exercise of options and restricted stock	–	(22)	–	–	–	–	(22)
Other	–	–	–	1	–	–	1
Total dividends and other transactions with shareholders	3	(73)	249	(323)	–	–	(144)
Comprehensive income (loss):							
Net income	–	–	–	1,145	–	10	1,155
Other comprehensive income (loss):							
Cumulative translation adjustment	–	–	–	–	(5)	–	(5)
Defined benefit and other postretirement plans, net	–	–	–	–	2	–	2
Net unrealized gains on investments, net of tax provision of $3	–	–	–	–	5	–	5
Total comprehensive income	–	–	–	1,145	2	10	1,157
Balance at December 31, 2009	$ 2,669	$ 411	$ (5,002)	$ 10,863	$ (213)	$ 29	$ 8,757
Cash dividends paid	–	–	–	(327)	–	–	(327)
Stock plans	5	(37)	252	–	–	–	220
Common shares purchased	–	–	(141)	–	–	–	(141)
Tax loss from exercise of options and restricted stock	–	(18)	–	–	–	–	(18)
Other	–	–	–	–	–	(21)	(21)
Total dividends and other transactions with shareholders	5	(55)	111	(327)	–	(21)	(287)
Treasury shares issued for acquisition	–	(17)	120	–	–	–	103
Comprehensive income (loss):							
Net income	–	–	–	1,835	–	7	1,842
Other comprehensive income (loss):							
Cumulative translation adjustment	–	–	–	–	(1)	–	(1)
Defined benefit and other postretirement plans adjustments, net	–	–	–	–	(26)	(1)	(27)
Total comprehensive income	–	–	–	1,835	(27)	6	1,814
Balance at December 31, 2010	$ 2,674	$ 339	$ (4,771)	$ 12,371	$ (240)	$ 14	$10,387
Cash dividends paid	–	–	–	(330)	–	–	(330)
Stock plans	9	82	267	–	–	–	358
Common shares purchased	–	–	(43)	–	–	–	(43)
Tax loss from exercise of options and restricted stock	–	34	–	–	–	–	34
Total dividends and other transactions with shareholders	9	116	224	(330)	–	–	19
Comprehensive income (loss):							
Net income	–	–	–	2,839	–	5	2,844
Other comprehensive income (loss):							
Defined benefit and other postretirement plans adjustments, net	–	–	–	–	(33)	(1)	(34)
Total comprehensive income	–	–	–	2,839	(33)	4	2,810
Balance at December 31, 2011	$ 2,683	$ 455	$ (4,547)	$ 14,880	$ (273)	$ 18	$13,216

Accumulated other comprehensive loss	December 31		
Millions of dollars	2011	2010	2009
Cumulative translation adjustment	$ (66)	$ (66)	$ (65)
Defined benefit and other postretirement liability adjustments (a)	(208)	(175)	(149)
Unrealized gains on investments	1	1	1
Total accumulated other comprehensive loss	$ (273)	$ (240)	$ (213)

(a) Included net actuarial losses for our international pension plans of $184 million at December 31, 2011, $170 million at December 31, 2010, and $149 million at December 31, 2009.

Shares of common stock	December 31		
Millions of shares	2011	2010	2009
Issued	1,073	1,069	1,067
In treasury	(152)	(159)	(165)
Total shares of common stock outstanding	921	910	902

Our stock repurchase program has an authorization of $5.0 billion, of which $1.7 billion remained available at December 31, 2011. The program does not require a specific number of shares to be purchased and the program may be effected through solicited or unsolicited transactions in the market or in privately negotiated transactions. The program may be terminated or suspended at any time. From the inception of this program in February 2006 through December 31, 2011, we have repurchased approximately 96 million shares of our common stock for approximately $3.3 billion at an average price per share of $34.22. There were no stock repurchases under the program in 2011.

Preferred Stock

Our preferred stock consists of five million total authorized shares at December 31, 2011, of which none are issued.

Stock Incentive Plans

The following table summarizes stock-based compensation costs for the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31		
Millions of dollars	2011	2010	2009
Stock-based compensation cost	$ 198	$ 158	$ 143
Tax benefit	$ (61)	$ (50)	$ (46)
Stock-based compensation cost, net of tax	$ 137	$ 108	$ 97

Our Stock and Incentive Plan, as amended (Stock Plan), provides for the grant of any or all of the following types of stock-based awards:

- stock options, including incentive stock options and nonqualified stock options;
- restricted stock awards;
- restricted stock unit awards;
- stock appreciation rights; and
- stock value equivalent awards.

There are currently no stock appreciation rights or stock value equivalent awards outstanding.

Under the terms of the Stock Plan, approximately 133 million shares of common stock have been reserved for issuance to employees and non-employee directors. At December 31, 2011, approximately 14 million shares were available for future grants under the Stock Plan. The stock to be offered pursuant to the grant of an award under the Stock Plan may be authorized but unissued common shares or treasury shares.

In addition to the provisions of the Stock Plan, we also have stock-based compensation provisions under our Restricted Stock Plan for Non-Employee Directors and our Employee Stock Purchase Plan (ESPP).

Each of the active stock-based compensation arrangements is discussed below.

Stock options

The majority of our options are generally issued during the second quarter of the year. All stock options under the Stock Plan are granted at the fair market value of our common stock at the grant date. Employee stock options vest ratably over a three- or four-year period and generally expire 10 years from the grant date. Compensation expense for stock options is generally recognized on a straight line basis over the entire vesting period. No further stock option grants are being made under the stock plans of acquired companies.

The following table represents our stock options activity during 2011.

Stock Options	Number of Shares *(in millions)*	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term *(years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding at January 1, 2011	15.8	$ 26.79		
Granted	3.4	43.87		
Exercised	(3.9)	22.05		
Forfeited/expired	(0.4)	33.54		
Outstanding at December 31, 2011	14.9	$ 31.74	6.7	$ 94
Exercisable at December 31, 2011	8.5	$ 29.07	5.3	$ 68

The total intrinsic value of options exercised was $102 million in 2011, $38 million in 2010, and $10 million in 2009. As of December 31, 2011, there was $55 million of unrecognized compensation cost, net of estimated forfeitures, related to nonvested stock options, which is expected to be recognized over a weighted average period of approximately 2 years.

Cash received from option exercises was $160 million during 2011, $102 million during 2010, and $74 million during 2009.

The fair value of options at the date of grant was estimated using the Black-Scholes option pricing model. The expected volatility of options granted was a blended rate based upon implied volatility calculated on actively traded options on our common stock and upon the historical volatility of our common stock. The expected term of options granted was based upon historical observation of actual time elapsed between date of grant and exercise of options for all employees. The assumptions and resulting fair values of options granted were as follows:

	Year Ended December 31		
	2011	2010	2009
Expected term (in years)	5.20	5.27	5.18
Expected volatility	40%	40%	53%
Expected dividend yield	0.69 – 1.01%	0.99 – 1.71%	1.23 – 2.55%
Risk-free interest rate	0.93 – 2.29%	1.20 – 2.78%	1.38 – 2.47%
Weighted average grant-date fair value per share	$ 15.61	$ 9.94	$ 9.36

Restricted stock

Restricted shares issued under the Stock Plan are restricted as to sale or disposition. These restrictions lapse periodically over an extended period of time not exceeding 10 years. Restrictions may also lapse for early retirement and other conditions in accordance with our established policies. Upon termination of employment, shares on which restrictions have not lapsed must be returned to us, resulting in restricted stock forfeitures. The fair market value of the stock on the date of grant is amortized and charged to income on a straight-line basis over the requisite service period for the entire award.

Our Restricted Stock Plan for Non-Employee Directors (Directors Plan) allows for each non-employee director to receive an annual award of 800 restricted shares of common stock as a part of their compensation. These awards have a minimum restriction period of six months, and the restrictions lapse upon the earlier of mandatory director retirement at age 72 or early retirement from the Board after four years of service. The fair market value of the stock on the date of grant is amortized over the lesser of the time from the grant date to age 72 or the time from the grant date to completion of four years of service on the Board. We reserved 200,000 shares of common stock for issuance to non-employee directors, which may be authorized but unissued common shares or treasury shares. At December 31, 2011, 145,600 shares had been issued to non-employee directors under this plan. There were 7,200 shares, 8,000 shares, and 8,000 shares of restricted stock awarded under the Directors Plan in 2011, 2010, and 2009. In addition, during 2011, our non-employee directors were awarded 19,395 shares of restricted stock under the Stock Plan, which are included in the table below.

The following table represents our Stock Plan and Directors Plan restricted stock awards and restricted stock units granted, vested, and forfeited during 2011.

Restricted Stock	Number of Shares *(in millions)*	Weighted Average Grant-Date Fair Value per Share
Nonvested shares at January 1, 2011	13.3	$ 28.10
Granted	5.4	43.35
Vested	(3.7)	28.81
Forfeited	(0.8)	32.59
Nonvested shares at December 31, 2011	14.2	$ 33.45

The weighted average grant-date fair value of shares granted during 2010 was $29.39 and during 2009 was $22.90. The total fair value of shares vested during 2011 was $165 million, during 2010 was $100 million, and during 2009 was $59 million. As of December 31, 2011, there was $352 million of unrecognized compensation cost, net of estimated forfeitures, related to nonvested restricted stock, which is expected to be recognized over a weighted average period of 4 years.

Employee Stock Purchase Plan

Under the ESPP, eligible employees may have up to 10% of their earnings withheld, subject to some limitations, to be used to purchase shares of our common stock. Unless the Board of Directors shall determine otherwise, each six-month offering period commences on January 1 and July 1 of each year. The price at which common stock may be purchased under the ESPP is equal to 85% of the lower of the fair market value of the common stock on the commencement date or last trading day of each offering period. Under this plan, 44 million shares of common stock have been reserved for issuance. They may be authorized but unissued shares or treasury shares. As of December 31, 2011, 25.3 million shares have been sold through the ESPP.

The fair value of ESPP shares was estimated using the Black-Scholes option pricing model. The expected volatility was a one-year historical volatility of our common stock. The assumptions and resulting fair values were as follows:

	Offering period July 1 through December 31		
	2011	2010	2009
Expected term (in years)	0.5	0.5	0.5
Expected volatility	34%	43%	80%
Expected dividend yield	0.70%	1.44%	1.74%
Risk-free interest rate	0.10%	0.21%	0.33%
Weighted average grant-date fair value per share	$ 12.57	$ 6.72	$ 7.66

	Offering period January 1 through June 30		
	2011	2010	2009
Expected term (in years)	0.5	0.5	0.5
Expected volatility	43%	48%	71%
Expected dividend yield	0.88%	1.15%	1.85%
Risk-free interest rate	0.20%	0.19%	0.27%
Weighted average grant-date fair value per share	$ 10.99	$ 8.81	$ 6.69

Note 11. Income per Share

Basic income per share is based on the weighted average number of common shares outstanding during the period. Diluted income per share includes additional common shares that would have been outstanding if potential common shares with a dilutive effect had been issued.

A reconciliation of the number of shares used for the basic and diluted income per share calculations is as follows:

Millions of shares	2011	2010	2009
Basic weighted average common shares outstanding	918	908	900
Dilutive effect of stock options	4	3	2
Diluted weighted average common shares outstanding	922	911	902

Excluded from the computation of diluted income per share are options to purchase three million shares of common stock that were outstanding in 2011, five million shares of common stock that were outstanding in 2010, and seven million shares of common stock that were outstanding in 2009. These options were outstanding during these years but were excluded because they were antidilutive, as the option exercise price was greater than the average market price of the common shares.

Note 12. Financial Instruments and Risk Management

At December 31, 2011, we held $150 million of short-term, United States Treasury securities with maturities that extend through February 2012 compared to $653 million of short-term, United States Treasury securities at December 31, 2010. These securities are accounted for as available-for-sale and recorded at fair value, based on quoted market prices, in “Investments in marketable securities” on our consolidated balance sheets. The carrying amount of cash and equivalents, investments in marketable securities, receivables, and accounts payable, as reflected in the consolidated balance sheets, approximates fair value due to the short maturities of these instruments. We have no financial instruments measured at fair value using unobservable inputs.

The fair value of our long-term debt was $6.2 billion as of December 31, 2011 and $4.6 billion as of December 31, 2010, which differs from the carrying amount of $4.8 billion as of December 31, 2011 and $3.8 billion as of December 31, 2010, on our consolidated balance sheets. As of December 31, 2011, $3.6 billion of the fair value of our long-term debt and as of December 31, 2010, $4.2 billion of the fair value of our long-term debt were calculated using quoted prices in active markets for identical liabilities. As of December 31, 2011, $2.6 billion of the fair value of our long-term debt and as of December 31, 2010, $422 million of the fair value of our long-term debt were calculated using significant observable inputs for similar liabilities.

We are exposed to market risk from changes in foreign currency exchange rates and interest rates. We selectively manage these exposures through the use of derivative instruments, including forward exchange contracts and interest rate swaps. The objective of our risk management strategy is to minimize the volatility from fluctuations in foreign currency and interest rates. We do not use derivative instruments for trading purposes. The fair value of our forward exchange contracts and interest rate swaps was not material as of December 31, 2011. The counterparties to our forward exchange contracts and interest rate swaps are global commercial and investment banks.

Foreign currency exchange risk

We have operations in many international locations and are involved in transactions denominated in currencies other than the United States dollar, our functional currency, which exposes us to foreign currency exchange rate risk. Techniques in managing foreign currency exchange risk include, but are not limited to, foreign currency borrowing and investing and the use of currency derivative instruments. We attempt to selectively manage significant exposures to potential foreign currency exchange losses based on current market conditions, future operating activities, and the associated cost in relation to the perceived risk of loss. The purpose of our foreign currency risk management activities is to minimize the risk that our cash flows from the sale and purchase of services and products in foreign currencies will be adversely affected by changes in exchange rates.

We use forward exchange contracts to manage our exposure to fluctuations in the currencies of the countries in which we do the majority of our international business. These forward exchange contracts are not treated as hedges for accounting purposes, generally have an expiration date of one year or less, and are not exchange traded. While forward exchange contracts are subject to fluctuations in value, the fluctuations are generally offset by the value of the underlying exposures being managed. The use of some of these contracts may limit our ability to benefit from favorable fluctuations in foreign currency exchange rates.

Forward exchange contracts are not utilized to manage exposures in some currencies due primarily to the lack of available markets or cost considerations (non-traded currencies). We attempt to manage our working capital position to minimize foreign currency exposure in non-traded currencies and recognize that pricing for the services and products offered in these countries should account for the cost of exchange rate devaluations. We have historically incurred transaction losses in non-traded currencies.

The notional amounts of open forward exchange contracts were $268 million at December 31, 2011 and $356 million at December 31, 2010. The notional amounts of our forward exchange contracts do not generally represent amounts exchanged by the parties, and thus are not a measure of our exposure or of the cash requirements related to these contracts. As such, cash flows related to these contracts are typically not material. The amounts exchanged are calculated by reference to the notional amounts and by other terms of the contracts, such as exchange rates.

Interest rate risk

We are subject to interest rate risk on our long-term debt. Our marketable securities and short-term borrowings do not give rise to significant interest rate risk due to their short-term nature. We had fixed rate long-term debt totaling $4.8 billion at December 31, 2011 and fixed rate long-term debt totaling $3.8 billion at December 31, 2010 with none maturing before May 2017.

We maintain an interest rate management strategy that is intended to mitigate the exposure to changes in interest rates in the aggregate for our investment portfolio. During the second quarter of 2011, we entered into a series of interest rate swaps relating to two of our debt instruments with a total notional amount of $1.0 billion at a weighted-average, LIBOR-based, floating rate of 3.57% as of December 31, 2011. We utilize interest rate swaps to effectively convert a portion of our fixed rate debt to floating rates. These interest rate swaps, which expire when the underlying debt matures, are designated as fair value hedges of the underlying debt and are determined to be highly effective. The fair value of our interest rate swaps are included in “Other assets” in our consolidated balance sheets as of December 31, 2011. The fair value of our interest rate swaps was determined using an income approach model with inputs, such as the notional amount, LIBOR rate spread, and settlement terms that are observable in the market or can be derived from or corroborated by observable data. We did not have any interest rate swaps outstanding as of December 31, 2010. At December 31, 2011, we had fixed rate debt aggregating $3.8 billion and variable rate debt aggregating $1.0 billion, after taking into account the effects of the interest rate swaps.

Credit risk

Financial instruments that potentially subject us to concentrations of credit risk are primarily cash equivalents, investments in marketable securities, and trade receivables. It is our practice to place our cash equivalents and investments in marketable securities in high quality investments with various institutions. We derive the majority of our revenue from selling products and providing services to the energy industry. Within the energy industry, our trade receivables are generated from a broad and diverse group of customers, although a significant amount of our trade receivables are generated in the United States. We maintain an allowance for losses based upon the expected collectability of all trade accounts receivable.

We do not have any significant concentrations of credit risk with any individual counterparty to our derivative contracts. We select counterparties to those contracts based on our belief that each counterparty's profitability, balance sheet, and capacity for timely payment of financial commitments is unlikely to be materially adversely affected by foreseeable events.

Note 13. Retirement Plans

Our company and subsidiaries have various plans that cover a significant number of our employees. These plans include defined contribution plans, defined benefit plans, and other postretirement plans:

- our defined contribution plans provide retirement benefits in return for services rendered. These plans provide an individual account for each participant and have terms that specify how contributions to the participant's account are to be determined rather than the amount of pension benefits the participant is to receive. Contributions to these plans are based on pretax income and/or discretionary amounts determined on an annual basis. Our expense for the defined contribution plans for continuing operations totaled $245 million in 2011, $196 million in 2010, and $186 million in 2009;
- our defined benefit plans, which include both funded and unfunded pension plans, define an amount of pension benefit to be provided, usually as a function of age, years of service, and/or compensation. The unfunded obligations and net periodic benefit cost of our United States defined benefit plans were not material for the periods presented; and
- our postretirement medical plans are offered to specific eligible employees. The accumulated benefit obligations and net periodic benefit cost for these plans were not material for the periods presented.

Funded status

For our international pension plans at December 31, 2011, the projected benefit obligation was $928 million and the fair value of plan assets was $705 million, which resulted in an unfunded obligation of $223 million. At December 31, 2010, the projected benefit obligation was $908 million and the fair value of plan assets was $691 million, which resulted in an unfunded obligation of $217 million. The accumulated benefit obligation for our international plans was $868 million at December 31, 2011 and $829 million at December 31, 2010.

The following table presents additional information about our international pension plans.

Millions of dollars	2011	2010
Amounts recognized on the Consolidated Balance Sheets		
Accrued employee compensation and benefits	$ 10	$ 15
Employee compensation and benefits	213	202
Pension plans in which projected benefit obligation exceeded plan assets at December 31		
Projected benefit obligation	$ 928	$ 902
Fair value of plan assets	705	685
Pension plans in which accumulated benefit obligation exceeded plan assets at December 31		
Accumulated benefit obligation	$ 784	$ 764
Fair value of plan assets	621	614

Fair value measurements of plan assets

The following table sets forth by level within the fair value hierarchy the fair value of assets held by our international pension plans.

Millions of dollars	Quoted Prices in Active Markets for Identical Assets	Significant Observable Inputs for Similar Assets	Significant Unobservable Inputs	Total
Common/collective trust funds (a)				
Equity funds	$ –	$ 241	$ –	$ 241
Bond funds	–	110	–	110
Balanced funds	–	12	–	12
Corporate bonds	–	89	–	89
United States equity securities	67	–	–	67
Non-United States equity securities	64	–	–	64
Other assets	15	16	91	122
Fair value of plan assets at December 31, 2011	$ 146	$ 468	$ 91	$ 705
Common/collective trust funds (a)				
Equity funds	$ –	$ 155	$ –	$ 155
Bond funds	–	97	–	97
Balanced funds	–	14	–	14
Non-United States equity securities	133	–	–	133
Corporate bonds	–	84	–	84
United States equity securities	41	–	–	41
Other assets	82	6	79	167
Fair value of plan assets at December 31, 2010	$ 256	$ 356	$ 79	$ 691

(a) Strategies are generally to invest in equity or debt securities, or a combination thereof, that match or outperform certain predefined indices.

Equity securities are traded in active markets and valued based on their quoted fair value by independent pricing vendors. Government bonds and corporate bonds are valued using quotes from independent pricing vendors based on recent trading activity and other relevant information, including market interest rate curves, referenced credit spreads, and estimated prepayment rates. Common/collective trust funds are valued at the net asset value of units held by the plans at year-end.

Our investment strategy varies by country depending on the circumstances of the underlying plan. Typically, less mature plan benefit obligations are funded by using more equity securities, as they are expected to achieve long-term growth while exceeding inflation. More mature plan benefit obligations are funded using more fixed income securities, as they are expected to produce current income with limited volatility. The fixed income allocation is generally invested with a similar maturity profile to that of the benefit obligations to ensure that changes in interest rates are adequately reflected in the assets of the plan. Risk management practices include diversification by issuer, industry, and geography, as well as the use of multiple asset classes and investment managers within each asset class.

For our United Kingdom pension plan, which constituted 74% of our international pension plans' projected benefit obligations at December 31, 2011, the target asset allocation is 65% equity securities and 35% fixed income securities.

Net periodic benefit cost

Net periodic benefit cost for our international pension plans was $27 million in 2011, $28 million in 2010, and $32 million in 2009.

Actuarial assumptions

Certain weighted-average actuarial assumptions used to determine benefit obligations of our international pension plans at December 31 were as follows:

	2011	2010
Discount rate	5.2%	5.7%
Rate of compensation increase	5.4%	5.2%

Certain weighted-average actuarial assumptions used to determine net periodic benefit cost of our international pension plans for the years ended December 31 were as follows:

	2011	2010	2009
Discount rate	7.1%	7.9%	7.4%
Expected long-term return on plan assets	5.7%	5.6%	5.6%
Rate of compensation increase	6.2%	6.4%	5.7%

Assumed long-term rates of return on plan assets, discount rates for estimating benefit obligations, and rates of compensation increases vary by plan according to local economic conditions. Discount rates were determined based on the prevailing market rates of a portfolio of high-quality debt instruments with maturities matching the expected timing of the payment of the benefit obligations. Expected long-term rates of return on plan assets were determined based upon an evaluation of our plan assets and historical trends and experience, taking into account current and expected market conditions.

Expected cash flows

Contributions. Funding requirements for each plan are determined based on the local laws of the country where such plan resides. In certain countries the funding requirements are mandatory, while in other countries they are discretionary. We currently expect to contribute $11 million to our international pension plans in 2012.

Benefit payments. Expected benefit payments over the next 10 years are approximately $25 million annually for our international pension plans.

Note 14. Accounting Standards Recently Adopted

In September 2011, the Financial Accounting Standards Board (FASB) issued an update to existing guidance on the assessment of goodwill impairment. This update simplifies the assessment of goodwill for impairment by allowing companies to consider qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before performing the two step impairment review process. It also amends the examples of events or circumstances that would be considered in a goodwill impairment evaluation. We have elected to early adopt this update to be effective for the fiscal year beginning January 1, 2011. The adoption of this update did not have an impact on our annual goodwill assessment.

On January 1, 2011, we adopted an update issued by the FASB to existing guidance on revenue recognition for arrangements with multiple deliverables. This update allows companies to allocate consideration for qualified separate deliverables using estimated selling price for both delivered and undelivered items when vendor-specific objective evidence or third-party evidence is unavailable. It also requires additional disclosures on the nature of multiple element arrangements, the types of deliverables under the arrangements, the general timing of their delivery, and significant factors and estimates used to determine estimated selling prices. The update is effective for fiscal years beginning after June 15, 2010. The adoption of this update did not have a material impact on our consolidated financial statements or existing revenue recognition policies.

HALLIBURTON COMPANY
Selected Financial Data [1]
(Unaudited)

Millions of dollars and shares except per share and employee data	Year Ended December 31 2011	2010	2009	2008	2007
Total revenue	$ 24,829	$ 17,973	$ 14,675	$ 18,279	$ 15,264
Total operating income	$ 4,737	$ 3,009	$ 1,994	$ 4,010	$ 3,498
Nonoperating expense, net	(288)	(354)	(312)	(161)	(51)
Income from continuing operations before income taxes	4,449	2,655	1,682	3,849	3,447
Provision for income taxes	(1,439)	(853)	(518)	(1,211)	(907)
Income from continuing operations	$ 3,010	$ 1,802	$ 1,164	$ 2,638	$ 2,540
Income (loss) from discontinued operations	(166)	40	(9)	(423)	996
Net income	$ 2,844	$ 1,842	$ 1,155	$ 2,215	$ 3,536
Noncontrolling interest in net (income) loss of subsidiaries	(5)	(7)	(10)	9	(50)
Net income attributable to company	$ 2,839	$ 1,835	$ 1,145	$ 2,224	$ 3,486
Amounts attributable to company shareholders:					
Continuing operations	$ 3,005	$ 1,795	$ 1,154	$ 2,647	$ 2,511
Discontinued operations	(166)	40	(9)	(423)	975
Net income	2,839	1,835	1,145	2,224	3,486
Basic income per share attributable to shareholders:					
Continuing operations	$ 3.27	$ 1.98	$ 1.28	$ 3.00	$ 2.73
Net income	3.09	2.02	1.27	2.52	3.79
Diluted income per share attributable to shareholders:					
Continuing operations	3.26	1.97	1.28	2.91	2.63
Net income	3.08	2.01	1.27	2.45	3.65
Cash dividends per share	0.36	0.36	0.36	0.36	0.35
Return on average shareholders' equity	24.06%	19.17%	13.88%	30.24%	48.31%
Financial position:					
Net working capital	$ 7,456	$ 6,129	$ 5,749	$ 4,630	$ 5,162
Total assets	23,677	18,297	16,538	14,385	13,135
Property, plant, and equipment, net	8,492	6,842	5,759	4,782	3,630
Long-term debt (including current maturities)	4,820	3,824	4,574	2,612	2,779
Total shareholders' equity	13,216	10,387	8,757	7,744	6,966
Total capitalization	18,097	14,241	13,331	10,369	9,756
Basic weighted average common shares outstanding	918	908	900	883	919
Diluted weighted average common shares outstanding	922	911	902	909	955
Other financial data:					
Capital expenditures	$ 2,953	$ 2,069	$ 1,864	$ 1,824	$ 1,583
Long-term borrowings (repayments), net	978	(790)	1,944	(861)	(7)
Depreciation, depletion, and amortization	1,359	1,119	931	738	583
Payroll and employee benefits	6,756	5,370	4,783	5,264	4,585
Number of employees	68,000	58,000	51,000	57,000	51,000

(1) All periods presented reflect the reclassification of KBR, Inc. to discontinued operations in the first quarter of 2007.

HALLIBURTON COMPANY
Quarterly Data and Market Price Information [1]
(Unaudited)

Millions of dollars except per share data	Quarter First	Second	Third	Fourth	Year
2011					
Revenue	$ 5,282	$ 5,935	$ 6,548	$ 7,064	$ 24,829
Operating income	814	1,161	1,332	1,430	4,737
Net income	511	741	685	907	2,844
Amounts attributable to company shareholders:					
Income from continuing operations	512	739	848	906	3,005
Income (loss) from discontinued operations	(1)	–	(165)	–	(166)
Net income attributable to company	511	739	683	906	2,839
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.56	0.81	0.92	0.98	3.27
Income (loss) from discontinued operations	–	–	(0.18)	–	(0.18)
Net income	0.56	0.81	0.74	0.98	3.09
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.56	0.80	0.92	0.98	3.26
Income (loss) from discontinued operations	–	–	(0.18)	–	(0.18)
Net income	0.56	0.80	0.74	0.98	3.08
Cash dividends paid per share	0.09	0.09	0.09	0.09	0.36
Common stock prices [1]					
High	50.47	51.45	57.77	40.43	57.77
Low	37.68	44.47	30.48	27.21	27.21
2010					
Revenue	$ 3,761	$ 4,387	$ 4,665	$ 5,160	$ 17,973
Operating income	449	762	818	980	3,009
Net income	207	483	545	607	1,842
Amounts attributable to company shareholders:					
Income from continuing operations	211	474	485	625	1,795
Income (loss) from discontinued operations	(5)	6	59	(20)	40
Net income attributable to company	206	480	544	605	1,835
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.23	0.52	0.53	0.69	1.98
Income (loss) from discontinued operations	–	0.01	0.07	(0.02)	0.04
Net income	0.23	0.53	0.60	0.67	2.02
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.23	0.52	0.53	0.68	1.97
Income (loss) from discontinued operations	–	0.01	0.07	(0.02)	0.04
Net income	0.23	0.53	0.60	0.66	2.01
Cash dividends paid per share	0.09	0.09	0.09	0.09	0.36
Common stock prices [1]					
High	34.87	35.22	33.84	41.73	41.73
Low	27.71	21.10	24.27	28.86	21.10

(1) New York Stock Exchange – composite transactions high and low intraday price.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance.

The information required for the directors of the Registrant is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the captions "Election of Directors" and "Involvement in Certain Legal Proceedings." The information required for the executive officers of the Registrant is included under Part I on pages 6 through 7 of this annual report. The information required for a delinquent form required under Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "Section 16(a) Beneficial Ownership Reporting Compliance," to the extent any disclosure is required. The information for our code of ethics is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "Corporate Governance." The information regarding our Audit Committee and the independence of its members, along with information about the audit committee financial expert(s) serving on the Audit Committee, is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "The Board of Directors and Standing Committees of Directors."

Item 11. Executive Compensation.

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table," "Grants of Plan-Based Awards in Fiscal 2011," "Outstanding Equity Awards at Fiscal Year End 2011," "2011 Option Exercises and Stock Vested," "2011 Nonqualified Deferred Compensation," "Employment Contracts and Change-in-Control Arrangements," "Post-Termination Payments," "Equity Compensation Plan Information," and "Directors' Compensation."

Item 12(a). Security Ownership of Certain Beneficial Owners.

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "Stock Ownership of Certain Beneficial Owners and Management."

Item 12(b). Security Ownership of Management.

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "Stock Ownership of Certain Beneficial Owners and Management."

Item 12(c). Changes in Control.

Not applicable.

Item 12(d). Securities Authorized for Issuance Under Equity Compensation Plans.

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption "Equity Compensation Plan Information."

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

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Corporate Governance” to the extent any disclosure is required and under the caption “The Board of Directors and Standing Committees of Directors.”

Item 14. Principal Accounting Fees and Services.

This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2012 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Fees Paid to KPMG LLP.”

PART IV

Item 15. Exhibits

1. Financial Statements:
   The reports of the Independent Registered Public Accounting Firm and the financial statements of the Company as required by Part II, Item 8, are included on pages 70 and 71 and pages 72 through 116 of this annual report. See index on page (i).

2. Financial Statement Schedules:
   The schedules listed in Regulation 210.5-04 have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

3. Exhibits:

Exhibit Number	Exhibits
3.1	Restated Certificate of Incorporation of Halliburton Company filed with the Secretary of State of Delaware on May 30, 2006 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed June 5, 2006, File No. 1-3492).
3.2	By-laws of Halliburton revised effective February 10, 2010 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed February 10, 2010, File No. 1-3492).
4.1	Form of debt security of 8.75% Debentures due February 12, 2021 (incorporated by reference to Exhibit 4(a) to the Form 8-K of Halliburton Company, now known as Halliburton Energy Services, Inc. (the Predecessor), dated as of February 20, 1991, File No. 1-3492).
4.2	Senior Indenture dated as of January 2, 1991 between the Predecessor and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee (incorporated by reference to Exhibit 4(b) to the Predecessor's Registration Statement on Form S-3 (Registration No. 33-38394) originally filed with the Securities and Exchange Commission on December 21, 1990), as supplemented and amended by the First Supplemental Indenture dated as of December 12, 1996 among the Predecessor, Halliburton and the Trustee (incorporated by reference to Exhibit 4.1 of Halliburton's Registration Statement on Form 8-B dated December 12, 1996, File No. 1-3492).
4.3	Resolutions of the Predecessor's Board of Directors adopted at a meeting held on February 11, 1991 and of the special pricing committee of the Board of Directors of the Predecessor adopted at a meeting held on February 11, 1991 and the special pricing committee's consent in lieu of meeting dated February 12, 1991 (incorporated by reference to Exhibit 4(c) to the Predecessor's Form 8-K dated as of February 20, 1991, File No. 1-3492).

4.4	Second Senior Indenture dated as of December 1, 1996 between the Predecessor and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, as supplemented and amended by the First Supplemental Indenture dated as of December 5, 1996 between the Predecessor and the Trustee and the Second Supplemental Indenture dated as of December 12, 1996 among the Predecessor, Halliburton and the Trustee (incorporated by reference to Exhibit 4.2 of Halliburton's Registration Statement on Form 8-B dated December 12, 1996, File No. 1-3492).
4.5	Third Supplemental Indenture dated as of August 1, 1997 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, to the Second Senior Indenture dated as of December 1, 1996 (incorporated by reference to Exhibit 4.7 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).
4.6	Fourth Supplemental Indenture dated as of September 29, 1998 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, to the Second Senior Indenture dated as of December 1, 1996 (incorporated by reference to Exhibit 4.8 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).
4.7	Resolutions of Halliburton's Board of Directors adopted by unanimous consent dated December 5, 1996 (incorporated by reference to Exhibit 4(g) of Halliburton's Form 10-K for the year ended December 31, 1996, File No. 1-3492).
4.8	Form of debt security of 6.75% Notes due February 1, 2027 (incorporated by reference to Exhibit 4.1 to Halliburton's Form 8-K dated as of February 11, 1997, File No. 1-3492).
4.9	Resolutions of Halliburton's Board of Directors adopted at a special meeting held on September 28, 1998 (incorporated by reference to Exhibit 4.10 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).
4.10	Copies of instruments that define the rights of holders of miscellaneous long-term notes of Halliburton and its subsidiaries have not been filed with the Commission. Halliburton agrees to furnish copies of these instruments upon request.
4.11	Form of debt security of 7.53% Notes due May 12, 2017 (incorporated by reference to Exhibit 4.4 to Halliburton's Form 10-Q for the quarter ended March 31, 1997, File No. 1-3492).

4.12 Form of Indenture dated as of April 18, 1996 between Dresser and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee (incorporated by reference to Exhibit 4 to Dresser's Registration Statement on Form S-3/A filed on April 19, 1996, Registration No. 333-01303), as supplemented and amended by Form of First Supplemental Indenture dated as of August 6, 1996 between Dresser and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), Trustee, for 7.60% Debentures due 2096 (incorporated by reference to Exhibit 4.1 to Dresser's Form 8-K filed on August 9, 1996, File No. 1-4003).

4.13 Second Supplemental Indenture dated as of October 27, 2003 between DII Industries, LLC and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Indenture dated as of April 18, 1996 (incorporated by reference to Exhibit 4.15 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.14 Third Supplemental Indenture dated as of December 12, 2003 among DII Industries, LLC, Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Indenture dated as of April 18, 1996, (incorporated by reference to Exhibit 4.16 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.15 Indenture dated as of October 17, 2003 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2003, File No. 1-3492).

4.16 Second Supplemental Indenture dated as of December 15, 2003 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.27 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.17 Form of note of 7.6% debentures due 2096 (included as Exhibit A to Exhibit 4.16 above).

4.18 Fourth Supplemental Indenture, dated as of September 12, 2008, between Halliburton and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.2 to Halliburton's Form 8-K filed September 12, 2008, File No. 1-3492).

4.19 Form of Global Note for Halliburton's 5.90% Senior Notes due 2018 (included as part of Exhibit 4.18).

4.20 Form of Global Note for Halliburton's 6.70% Senior Notes due 2038 (included as part of Exhibit 4.18).

4.21	Fifth Supplemental Indenture, dated as of March 13, 2009, between Halliburton and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.2 to Halliburton's Form 8-K filed March 13, 2009, File No. 1-3492).
4.22	Form of Global Note for Halliburton's 6.15% Senior Notes due 2019 (included as part of Exhibit 4.21).
4.23	Form of Global Note for Halliburton's 7.45% Senior Notes due 2039 (included as part of Exhibit 4.21).
4.24	Sixth Supplemental Indenture, dated as of November 14, 2011, between Halliburton and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.2 to Halliburton's Form 8-K filed November 14, 2011, File No. 1-3492).
4.25	Form of Global Note for Halliburton's 3.25% Senior Notes due 2021 (included as part of Exhibit 4.24).
4.26	Form of Global Note for Halliburton's 4.50% Senior Notes due 2041 (included as part of Exhibit 4.24).
10.1	Halliburton Company Restricted Stock Plan for Non-Employee Directors (incorporated by reference to Appendix B of the Predecessor's proxy statement dated March 23, 1993, File No. 1-3492).
10.2	Dresser Industries, Inc. Deferred Compensation Plan, as amended and restated effective January 1, 2000 (incorporated by reference to Exhibit 10.16 to Halliburton's Form 10-K for the year ended December 31, 2000, File No. 1-3492).
10.3	ERISA Excess Benefit Plan for Dresser Industries, Inc., as amended and restated effective June 1, 1995 (incorporated by reference to Exhibit 10.7 to Dresser's Form 10-K for the year ended October 31, 1995, File No. 1-4003).
10.4	ERISA Compensation Limit Benefit Plan for Dresser Industries, Inc., as amended and restated effective June 1, 1995 (incorporated by reference to Exhibit 10.8 to Dresser's Form 10-K for the year ended October 31, 1995, File No. 1-4003).
10.5	Employment Agreement (David J. Lesar) (incorporated by reference to Exhibit 10(n) to the Predecessor's Form 10-K for the year ended December 31, 1995, File No. 1-3492).
10.6	Employment Agreement (Mark A. McCollum) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2003, File No. 1-3492).

10.7	Halliburton Company Performance Unit Program (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended September 30, 2001, File No. 1-3492).
10.8	Employment Agreement (Albert O. Cornelison) (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended June 30, 2002, File No. 1-3492).
10.9	Form of Indemnification Agreement for Officers (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed August 3, 2007, File No. 1-3492).
10.10	Form of Indemnification Agreement for Directors (incorporated by reference to Exhibit 10.2 to Halliburton's Form 8-K filed August 3, 2007, File No. 1-3492).
10.11	2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.12	Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.13	Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.5 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.14	Halliburton Company Pension Equalizer Plan, as amended and restated effective March 1, 2007 (incorporated by reference to Exhibit 10.8 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.15	Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective January 1, 2007 (incorporated by reference to Exhibit 10.9 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.16	Retirement Plan for the Directors of Halliburton Company, as amended and restated effective July 1, 2007 (incorporated by reference to Exhibit 10.10 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).
10.17	Employment Agreement (James S. Brown) (incorporated by reference to Exhibit 10.36 to Halliburton's Form 10-K for the year ended December 31, 2007, File No. 1-3492).
10.18	Executive Agreement (Lawrence J. Pope) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed December 12, 2008, File No. 1-3492).
10.19	Halliburton Company Stock and Incentive Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Appendix B of Halliburton's proxy statement filed April 6, 2009, File No. 1-3492).

10.20	Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Appendix C of Halliburton's proxy statement filed April 6, 2009, File No. 1-3492).
10.21	Form of Nonstatutory Stock Option Agreement (incorporated by reference to Exhibit 10.4 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).
10.22	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.5 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).
10.23	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.6 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).
10.24	Form of Non-Employee Director Restricted Stock Agreement (incorporated by reference to Exhibit 99.5 of Halliburton's Form S-8 filed May 21, 2009, Registration No. 333-159394).
10.25	First Amendment to Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).
10.26	Amendment No. 1 to Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.2 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).
10.27	Halliburton Annual Performance Pay Plan, as amended and restated effective January 1, 2010 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).
10.28	Executive Agreement (Evelyn M. Angelle) (incorporated by reference to Exhibit 10.34 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).
10.29	Executive Agreement (Timothy J. Probert) (incorporated by reference to Exhibit 10.36 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).
10.30	Amendment to Executive Employment Agreement (James S. Brown) (incorporated by reference to Exhibit 10.39 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).
10.31	Amendment to Executive Employment Agreement (Albert O. Cornelison) (incorporated by reference to Exhibit 10.40 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).
10.32	Amendment to Executive Employment Agreement (Mark A. McCollum) (incorporated by reference to Exhibit 10.43 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

	10.33	Amendment No. 1 to 2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.41 to Halliburton's Form 10-K for the year ended December 31, 2010, File No. 1-3492).
	10.34	Executive Agreement (Joseph F. Andolino) (incorporated by reference to Exhibit 10.42 to Halliburton's Form 10-K for the year ended December 31, 2010, File No. 1-3492).
	10.35	Executive Agreement (Joe D. Rainey) (incorporated by reference to Exhibit 10.43 to Halliburton's Form 10-K for the year ended December 31, 2010, File No. 1-3492).
	10.36	U.S. $2,000,000,000 Five Year Revolving Credit Agreement among Halliburton, as Borrower, the Banks party thereto, and Citibank, N.A., as Agent (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed February 23, 2011, File No. 1-3492).
	10.37	First Amendment dated February 10, 2011 to Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3492).
	10.38	First Amendment to the Retirement Plan for the Directors of Halliburton Company, effective September 1, 2007 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3492).
	10.39	Underwriting Agreement, dated November 8, 2011, among Halliburton and Citigroup Global Markets Inc., Deutsche Bank Securities Inc., HSBC Securities (USA) Inc., RBS Securities Inc., Credit Suisse Securities (USA) LLC, Morgan Stanley & Co. LLC and the several other underwriters identified therein (incorporated by reference to Exhibit 1.1 to Halliburton's Form 8-K filed November 14, 2011, File No. 1-3492).
*	10.40	Executive Agreement (Christian A. Garcia).
*	10.41	First Amendment to Halliburton Company Restricted Stock Plan for Non-Employee Directors.
*	10.42	Form of Restricted Stock Agreement (Section 16 officers).
*	10.43	Form of Non-Employee Director Restricted Stock Agreement (Stock and Incentive Plan).
*	12.1	Statement of Computation of Ratio of Earnings to Fixed Charges.
*	21.1	Subsidiaries of the Registrant.
*	23.1	Consent of KPMG LLP.

*	24.1	Powers of attorney for the following directors signed in February 2012: Alan M. Bennett James R. Boyd Milton Carroll Nance K. Dicciani Murry S. Gerber S. Malcolm Gillis Abdallah S. Jum'ah Robert A. Malone J. Landis Martin Debra L. Reed
*	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**	32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**	32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	95	Mine Safety Disclosures.
*	101.INS	XBRL Instance Document
*	101.SCH	XBRL Taxonomy Extension Schema Document
*	101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*	101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*	101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*	101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this Form 10-K.
** Furnished with this Form 10-K.

SIGNATURES

As required by Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has authorized this report to be signed on its behalf by the undersigned authorized individuals on this 16th day of February, 2012.

HALLIBURTON COMPANY

By /s/ David J. Lesar
David J. Lesar
Chairman of the Board,
President, and Chief Executive Officer

As required by the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities indicated on this 16th day of February, 2012.

Signature	Title
/s/ David J. Lesar David J. Lesar	Chairman of the Board, President, Chief Executive Officer, and Director
/s/ Mark A. McCollum Mark A. McCollum	Executive Vice President and Chief Financial Officer
/s/ Evelyn M. Angelle Evelyn M. Angelle	Senior Vice President and Chief Accounting Officer

Signature	Title
* Alan M. Bennett Alan M. Bennett	Director
* James R. Boyd James R. Boyd	Director
* Milton Carroll Milton Carroll	Director
* Nance K. Dicciani Nance K. Dicciani	Director
* Murry S. Gerber Murry S. Gerber	Director
* S. Malcolm Gillis S. Malcolm Gillis	Director
* Abdallah S. Jum'ah Abdallah S. Jum'ah	Director
* Robert A. Malone Robert A. Malone	Director
* J. Landis Martin J. Landis Martin	Director
* Debra L. Reed Debra L. Reed	Director

* /s/ Christina M. Ibrahim
Christina M. Ibrahim, Attorney-in-fact

Board of Directors

David J. Lesar
Chairman of the Board, President and Chief Executive Officer, Halliburton Company (2000)

Alan M. Bennett
Retired President and Chief Executive Officer, H&R Block, Inc.
(2006) (A) (D)

James R. Boyd
Retired Chairman of the Board, Arch Coal, Inc.
(2006) (A) (B)

Milton Carroll
Chairman of the Board, CenterPoint Energy, Inc.
(2006) (B) (D)

Nance K. Dicciani
Retired President and Chief Executive Officer, Honeywell International Specialty Materials
(2009) (A) (C)

Murry S. Gerber
Retired Chairman and Chief Executive Officer, EQT Corporation
(2012) (A) (B)

S. Malcolm Gillis
University Professor, Rice University
(2005) (A) (C)

Abdallah S. Jum'ah
Retired President and Chief Executive Officer, Saudi Arabian Oil Company
(2010) (C) (D)

Robert A. Malone
President and Chief Executive Officer, First National Bank of Sonora, Texas
Retired Chairman of the Board and President, BP America Inc. (2009) (B) (C)

J. Landis Martin
Founder and Managing Director, Platte River Ventures, L.L.C.
(1998) (C) (D)

Debra L. Reed
Chief Executive Officer, Sempra Energy
(2001) (B) (D)

Corporate Officers

David J. Lesar
Chairman of the Board, President and Chief Executive Officer

Albert O. Cornelison, Jr.
Executive Vice President and General Counsel

Mark A. McCollum
Executive Vice President and Chief Financial Officer

Lawrence J. Pope
Executive Vice President of Administration and Chief Human Resources Officer

Timothy J. Probert
President, Strategy and Corporate Development

James S. Brown
President, Western Hemisphere

Joe D. Rainey
President, Eastern Hemisphere

Joseph F. Andolino
Senior Vice President, Tax

Evelyn M. Angelle
Senior Vice President and Chief Accounting Officer

Christian A. Garcia
Senior Vice President and Treasurer

Sherry D. Williams
Senior Vice President and Chief Ethics and Compliance Officer

Christina M. Ibrahim
Vice President and Corporate Secretary

Shareholder Information

Shares Listed
New York Stock Exchange
Symbol: HAL

Transfer Agent and Registrar
Computershare Shareowner Services
480 Washington Boulevard
Jersey City, New Jersey 07310-1900
Telephone: 800.279.1227
www.bnymellon.com/shareowner/isd

To contact Halliburton Investor Relations, shareholders may call the Company at 888.669.3920 or 281.871.2688, or send a message via email to investors@halliburton.com

(A) Member of the Audit Committee
(B) Member of the Compensation Committee
(C) Member of the Health, Safety and Environment Committee
(D) Member of the Nominating and Corporate Governance Committee

ANNUAL REPORT DESIGN: AXIOM, HOUSTON WWW.AXIOM.US.COM

HALLIBURTON

281.871.2699

www.halliburton.com

Printed in the USA

H09007