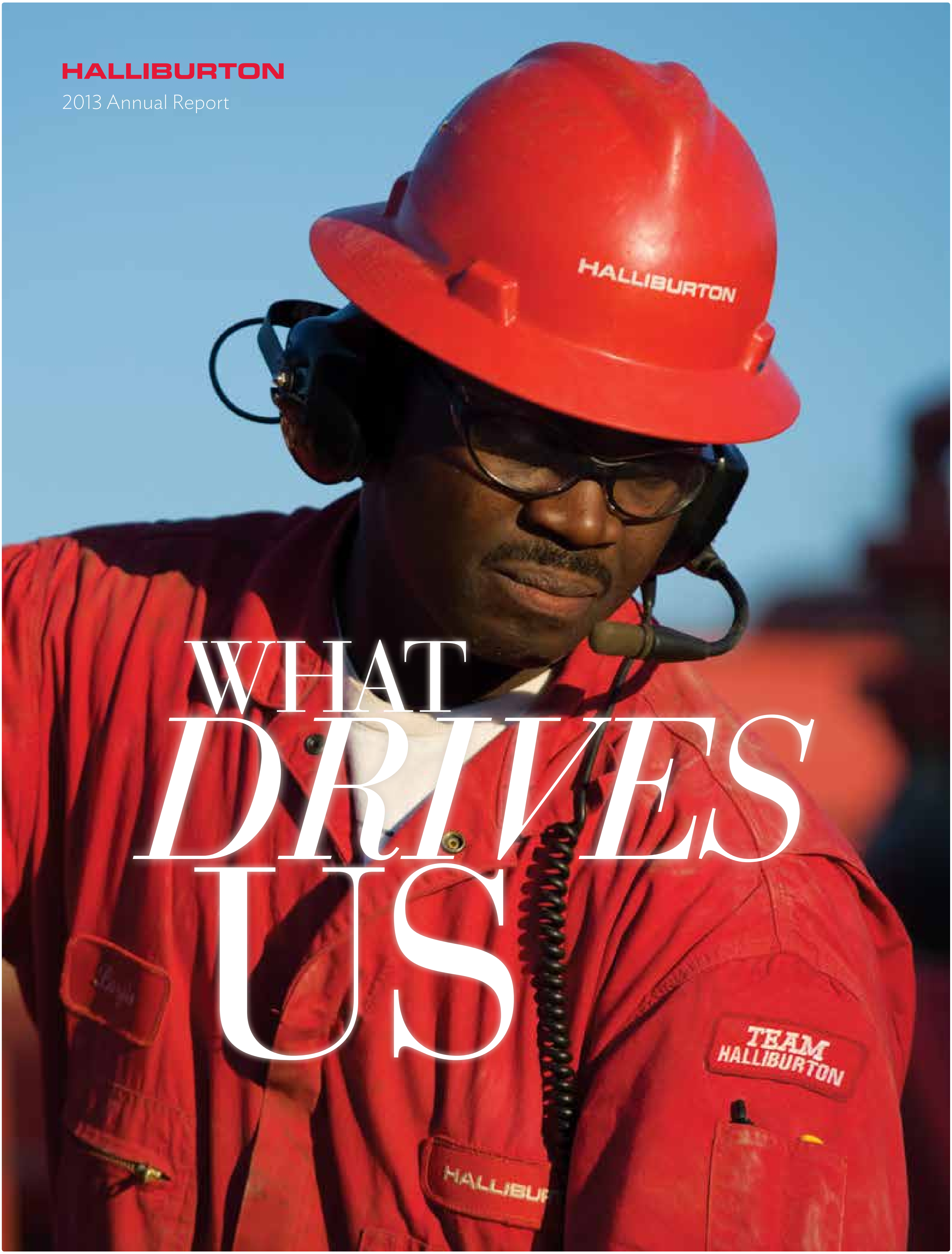
HALLIBURTON

2013 Annual Report

WHAT *DRIVES* US



WHAT *DRIVES* US

At Halliburton, the things that drive us keep us ahead. In this report, you will read about our insistence on setting bold goals, our focus on execution certainty and our determination to live up to the commitments we make to all of our stakeholders. You will also read about how we are staying the course with the consistent strategy that drove our growth since our 2010 Analyst Day.

Key accomplishments over the past three years:

31% **DEEPWATER**
Our deepwater revenue grew 31 percent per year, compared to 13 percent for the industry.

3x **MATURE FIELDS**
We achieved our goal of tripling the size of our mature fields business.

70% **UNCONVENTIONALS**
We led in North America, with revenue growth exceeding 70%.

EXECUTION CERTAINTY
Frac of the Future,™ coupled with our proprietary Battle Red smart phone field management tools, takes efficiency and reliability to new levels. In addition, we are also seeing environmental benefits from the use of natural gas-powered vehicles and pump trucks.

APPLIED TECHNOLOGY
Halliburton continues to lead in delivering pragmatic technologies that address our customers' challenges. With the opening of new technology centers in Brazil and Saudi Arabia, we continue globalizing our technology footprint for greater responsiveness to customer needs.

INTERNATIONAL FOOTPRINT
Our new completion tools manufacturing facility in Singapore supports our Eastern Hemisphere operations and greatly reduces the delivery times and costs needed to service this growing market. This is part of a strategic initiative to locate our infrastructure closer to the wellhead.

OVER 60%

CONSISTENT STRATEGY
In 2013, our three key growth markets – deepwater, mature fields and unconventionals – contributed over 60 percent of our global revenue.

FINANCIAL HIGHLIGHTS //

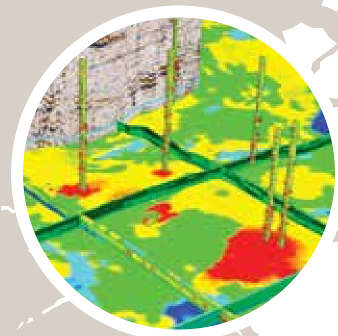
(Millions of dollars and shares, except per share data)	**2013**	2012	2011
Revenue	**$ 29,402**	$ 28,503	$ 24,829
Operating Income	**$ 3,138**	$ 4,159	$ 4,737
Amounts Attributable to Company Shareholders:			
Income from Continuing Operations	**$ 2,106**	$ 2,577	$ 3,005
Net Income	**$ 2,125**	$ 2,635	$ 2,839
Diluted Income per Share Attributable to Company Shareholders:			
Income from Continuing Operations	**$ 2.33**	$ 2.78	$ 3.26
Net Income	**$ 2.36**	$ 2.84	$ 3.08
Cash Dividends per Share	**$ 0.525**	$ 0.36	$ 0.36
Diluted Weighted Average Common Shares Outstanding	**902**	928	922
Working Capital[1]	**$ 8,678**	$ 8,334	$ 7,456
Capital Expenditures	**$ 2,934**	$ 3,566	$ 2,953
Long-Term Debt	**$ 7,816**	$ 4,820	$ 4,820
Debt to Total Capitalization[2]	***37%***	*24%*	*27%*
Depreciation, Depletion and Amortization	**$ 1,900**	$ 1,628	$ 1,359
Return on Average Capital Employed[3]	***11%***	*15%*	*19%*
Total Capitalization[4]	**$ 21,569**	$ 20,764	$ 18,097

[1] Working Capital is defined as total current assets less total current liabilities.

[2] Debt to Total Capitalization is defined as total debt divided by the sum of total debt plus total shareholders' equity.

[3] Return on Average Capital Employed is defined as net income before net interest expense divided by average capital employed. Capital employed includes total debt and total shareholders' equity.

[4] Total Capitalization is defined as total debt plus total shareholders' equity.



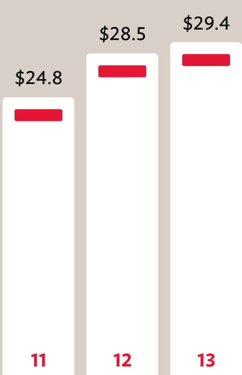
CYPHER℠

CYPHER℠ is an industry-leading integrated seismic-to-stimulation software platform incorporating seismic, logging, production and other data to build a full-scale asset model capable of predicting production with up to 93% accuracy during early trials. With each successive well, CYPHER℠ gets "smarter" and becomes more accurate at helping customers decide where to drill their well, where to land their well, where to complete and how to complete.

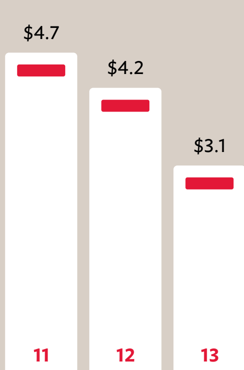
Gulf of Mexico

Successfully used for three deepwater wells in the Gulf of Mexico, Halliburton's Enhanced Single-Trip Multizone™ completion system was named "Best Deepwater Technology" at the World Oil awards.

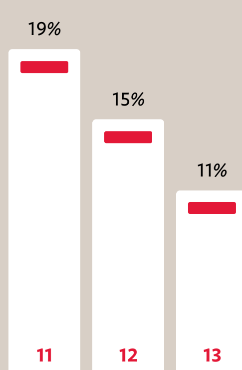
Revenue
in billions



Operating Income*
in billions



Return on Average Capital Employed*



*Includes a $1 billion charge in 2013 and a $300 million charge in 2012 related to the Macondo well incident.

ICE Core™
ICE Core (Integrated Computational Element) performs laboratory-grade analysis on downhole fluids during drilling operations. Spectroscopy is used to determine fluids composition, and the solid state tool design ensures maximum reliability.

Bayan
Work began on the Bayan field in Malaysia, a fully Integrated Asset Management contract where Halliburton can leverage its full suite of products and services as well as its extensive Consulting & Project Management expertise. A similar project was awarded in the Humapa field of Mexico, where work is expected to begin in 2014.

Saudi Arabia
Halliburton opened its new Unconventional and Reservoir Productivity Technology Center in Saudi Arabia, providing state-of-the-art solutions for conventional and unconventional reservoirs in the Kingdom and around the globe.

WHAT *DRIVES* OUR GROWTH //

INTERNATIONAL OPPORTUNITY
Halliburton has invested aggressively to build its international infrastructure and develop market opportunities. Active in more than 80 countries, we derived 48 percent of our 2013 revenue from outside North America. We expect the balance to continue shifting with the ongoing growth of our international business.

APPLIED TECHNOLOGY
Our global team of experts work together, and with our customers, to develop technology solutions to some of the world's most complex energy challenges. We have a proven track record of delivering technologies that are practical, quickly deployed and complement our reputation for outstanding service.

INTEGRATED SOLUTIONS
Integration of technologies and capabilities is the key to efficiency and outstanding execution at Halliburton. Integration drives consistency in our operations all across the world, allows us to meet technology challenges that cut across disciplines and supports the robust workflows required to execute complex projects.

WHAT *DRIVES* US //

To Our Shareholders,

At Halliburton, we believe in setting bold goals that stretch our abilities, drive our growth and reflect the long-term prospects for our business. Over the past three years, we grew our deepwater business at double the market rate, tripled the size of our mature fields business, extended our unconventionals leadership and delivered superior returns relative to our major competitors.

Halliburton's success is rooted in a sound strategy executed by an ambitious management team and a dedicated workforce that is never satisfied with the status quo. We are driven to provide execution certainty, deliver on our commitments and find new ways to increase value for customers. Our strategic focus on deepwater, mature fields and unconventionals has served us well, and these high-growth segments will continue to fuel our growth.

Deepwater Shows Robust Activity

Over the past five years, 60 percent of the total volume of all hydrocarbon discoveries were made in deepwater, and licensing activity is at an all-time high. With deepwater activity expanding to all regions of the world, the market is expected to grow 11 percent annually over the next five years.

The development segment is projected to see the strongest growth over the coming five years – 13 percent per year compared to four percent for exploration. This trend will benefit Halliburton, drawing on our number one position in completions, our integration capabilities and our reputation for execution certainty. By leveraging our infrastructure investments, building on our leadership in deepwater development and introducing technologies that maximize production from customer assets, we believe we can continue to outgrow the deepwater market by 25 percent over the next three years.

Mature Fields Play a Vital Role

On average, fields that are past their peak represent approximately 60 percent of International Oil Company (IOC) asset portfolios, and their production is estimated to be declining by more than eight percent per year. Compared to capital-intensive new development projects, mature fields can generate attractive returns for our customers and represent an important source of cash flow for them.

Robust demand and a meaningful increase in service intensity has multiplied revenue opportunities for large, integrated service providers as the market moves from the provision of discrete services to integrated solutions and ultimately to asset management arrangements. Very few service companies have the scale and the service portfolio to compete in this arena, which offers stable, long-term growth with limited capital investment. Our three-year goal is to again triple our mature fields business.

Unconventionals Market Gains Velocity

Over the past few years, the North American market shifted its focus from natural gas to liquids. Full-scale development of major unconventionals resource areas like the Permian Basin is now underway for many of our customers, who are striving to achieve the lowest cost per barrel of oil equivalent to ensure their economic success. We believe Halliburton is ahead of the curve in serving this market by providing the technologies, capabilities and expertise to help our customers meet their objectives in this challenging high velocity environment.

Revenue
$29.4 Billion

Operating Income
$3.1 Billion

Net Income
$2.1 Billion

Cash Dividends Per Share
$0.525

Capital Expenditures
$2.9 Billion

Return on Average Capital Employed
11 percent

We have made significant investments to ensure that we have the correct tools and capabilities to deliver better producing wells, built faster, at lower cost and with reduced risk. With the industry's most advanced delivery platform, we address both sides of the value equation, offering cost savings through superior efficiency plus advanced technologies and software that reduce uncertainty and improve production. We plan to extend our leadership position in North America and leverage our expertise to capture opportunities in emerging international unconventional markets.

Delivering on Our Commitments

We are pleased with our operational performance in these key markets. However, the ultimate measure of success for our shareholders is how well we deliver on our financial commitments to produce superior growth, margins and returns. During 2013, we grew our revenue to a new record of $29.4 billion. We maintained market leadership in North America and outgrew our primary competitors in international markets, which now represent 48 percent of company revenue. International infrastructure investments have supported our significant growth in these markets and provide us a platform for future revenue and margin growth.

During 2013, we demonstrated our strong commitment to delivering superior shareholder returns and reiterated our continued confidence in the strength of our business outlook. In addition to raising our dividend twice, for a total payout increase of 67 percent over our 2012 quarterly dividend rate, we repurchased approximately $4.4 billion, or 10 percent, of our outstanding common shares. We have been, and will continue to be, relentlessly focused on delivering best-in-class returns.

Extending the Momentum

Through consistent execution of a proven strategy, we have built a solid foundation on which to generate future growth and the momentum to drive it forward. The established market leader in North America, we continue to expand our global footprint to address emerging growth opportunities in international markets.

We recognize the vital role our stakeholders play in our success. We greatly appreciate the confidence our shareholders and customers continue to show in Halliburton and the exceptional contributions of our board of directors, employees and suppliers. After reading this report and discovering what drives us, we are confident that you will share our optimism and enthusiasm about the road ahead for Halliburton.

DAVID J. LESAR
Chairman of the Board,
President and
Chief Executive Officer

JEFFREY A. MILLER
Executive Vice President,
Chief Operating Officer and
Chief Health, Safety and
Environment Officer

MARK A. McCOLLUM
Executive Vice President
and Chief Financial Officer

LAWRENCE J. POPE
Executive Vice President
of Administration and Chief
Human Resources Officer

ROBB L. VOYLES
Executive Vice President
and General Counsel

TIMOTHY J. PROBERT
Strategic Advisor to the
Chief Executive Officer

Halliburton's deepwater growth rate was more than double that of the deepwater market over the past three years. We have invested aggressively to build our global infrastructure, technologies and capabilities, transforming the company from an emerging alternative into a compelling choice for customers seeking the technology and execution certainty we are known for.

The results we delivered over the past three years demonstrate the strength of our strategy to tap the large and growing deepwater market. We substantially exceeded our commitment to outgrow the market by at least 25 percent. We achieved revenue growth of 31 percent per year in a market that grew an average of 13 percent annually over the same period. More importantly, we built a solid foundation for the future, winning major contracts, strengthening key customer relationships and greatly increasing our competitiveness across the globe.

Infrastructure and Footprint

With more than $1 billion of infrastructure investments, we expanded our operations beyond the "golden triangle" – Gulf of Mexico, West Africa and Brazil – into 30 countries, establishing a presence in all of the world's deepwater markets. In addition to adding more than 50 operations facilities, our investments strengthened our capabilities to develop advanced technologies that provide a competitive advantage in the challenging deepwater arena. Our new technology development facilities include an acoustic center where we are accelerating the development of next-generation sonic tools, a perforating flow lab where we can simulate the effect of perforation under downhole conditions to reduce uncertainty, and a technology center in Brazil, the world's largest deepwater market.

Growth Through Technology

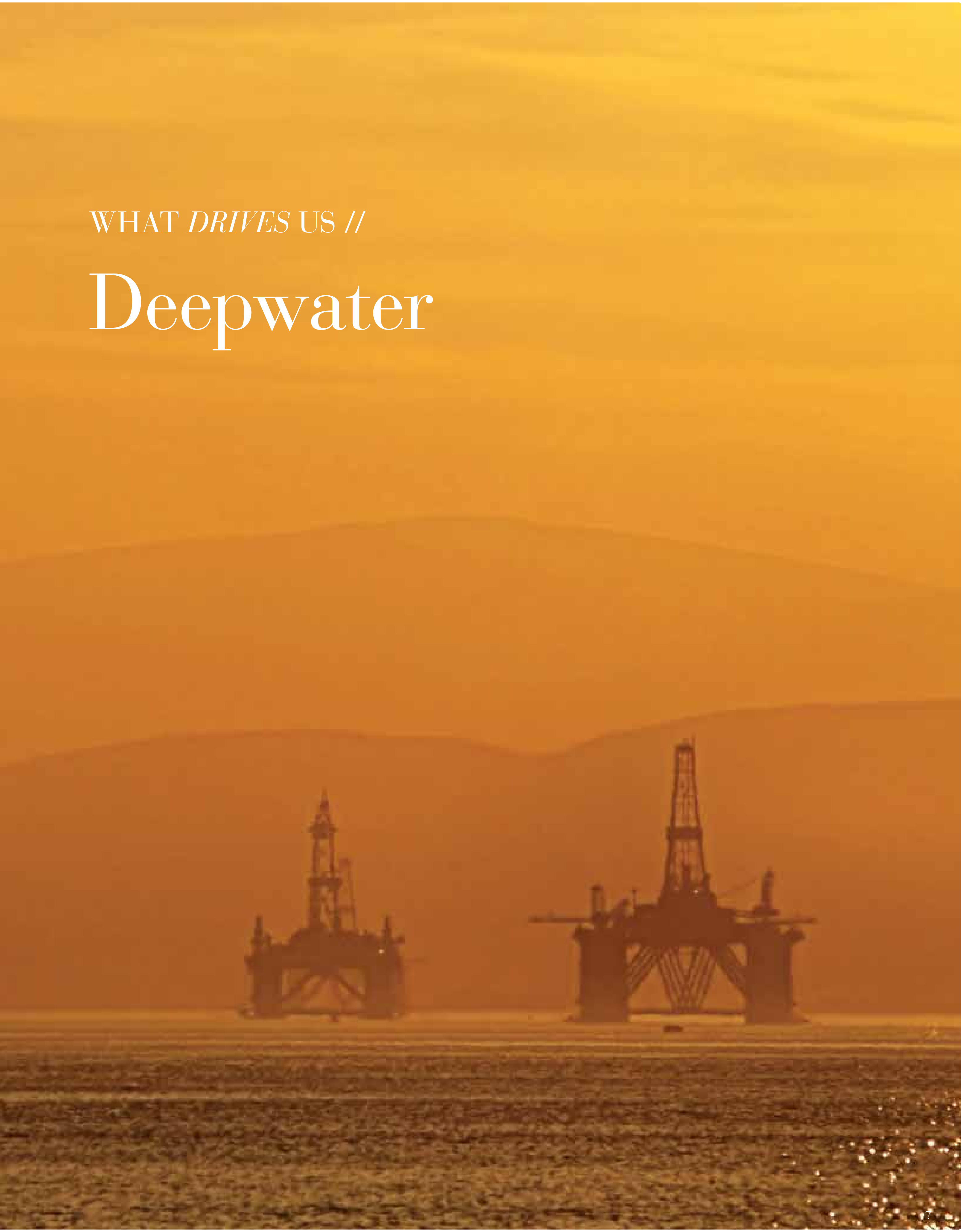
Adding to our broad suite of technologies to service the deepwater market, we have commercialized approximately 30 impactful products and services over the past three years. In addition to technologies that build on our leadership in the finding and completing phases of operations, we have launched innovations that strengthen our position in drilling and evaluation. Our focus on pragmatic technologies that fill identified needs has resulted in strong market adoption. Wireline and sampling jobs are up 260 percent, use of our Dynalink wireless testing system has grown 185 percent and our ESTMZ (Enhanced Single-Trip Multizone) completion system has captured 70 percent of the lower tertiary market in the Gulf of Mexico. We expect these high-end, high-margin technologies to be an ongoing driver of growth.

"Our vastly expanded footprint and technological capabilities have made Halliburton competitive in deepwater markets around the world. With the majority of our infrastructure investment behind us, our growing deepwater business will improve cost absorption and drive margins higher."

TIMOTHY J. PROBERT
Strategic Advisor to the Chief Executive Officer

WHAT *DRIVES* US //

Deepwater



WHAT *DRIVES* US //

Mature Fields

Sixty-five percent of hydrocarbons discovered are left in the reservoir today. With a large and growing percentage of customer assets in decline, the significant incremental production that can be delivered by increased recovery rates has made mature fields a compelling growth segment in which Halliburton tripled its revenue over the past three years.

The mature fields business offers a stable growth engine with increasing levels of service intensity as new technologies are deployed to boost recovery rates. Mature fields continue to generate attractive returns and cash flow for our customers, in turn driving strong demand for our services.

Opportunity Through Integration

We address the mature fields segment using three distinct commercial models – discrete services, integrated projects and, most recently, integrated asset management.

Halliburton's comprehensive suite of discrete services and technologies offers our customers a broad range of capabilities to restore, maintain and grow production from mature assets.

Integrated solutions combine multiple technologies and services needed to solve complex challenges across all aspects of mature fields operations, including: sub-surface analysis, drilling and completions infrastructure and facilities, and production operations. Our integrated approach to service delivery increases efficiency for our customers and provides enhanced growth opportunities for Halliburton.

Well Positioned for Premium Segments

Halliburton is fortunate to be one of a select number of service companies to have the technical, operational and financial capability to execute integrated asset management engagement on behalf of our customers. Over the past three years, we have built mature asset capabilities and developed proprietary execution models that have positioned us very well in this arena. These projects are long in duration and provide a stable base for long-term earnings. During 2013, we began work in the Bayan field in Malaysia and received a contract for the Humapa field in Mexico, where operations are expected to begin in 2014.

"Migrating our portfolio to incentivized asset management contracts is a core element of our strategy to triple our mature fields business over the next three years. By their integrated nature and long duration, these arrangements allow us to leverage our service delivery infrastructure to create steady revenue streams and attractive margins in an arena where very few companies can compete."

MARK A. McCOLLUM
Executive Vice President and Chief Financial Officer

Halliburton has built a leadership position in North American unconventionals by anticipating the market's evolution and developing technology to meet emerging needs. Initiatives underway for several years have prepared us for today's high-velocity environment where completing wells faster and better are key elements in delivering the lowest cost per barrel of oil equivalent (BOE).

Three years ago, we made a commitment to remain the undisputed leader in unconventionals, and we have done so by executing on a number of key strategies. We've focused holistically on the reservoir performance and pioneered integrated solutions that cut across product and service lines to solve customer challenges. More than 85 percent of our North American revenue now comes from integrated services. We also have built the industry's most efficient and effective delivery platform and taken the lead in environmentally sensitive solutions. Today, we are focused on leveraging proprietary technologies like CYPHER℠ to design and execute the best well plans, and to be the lowest cost-per-barrel provider for our customers.

Introducing HALvantage™

Three years ago, we created a blueprint for Frac of the Future.™ Now a reality, this concept is a game changer that has improved all aspects of surface efficiency, reducing our footprint as well as the equipment, personnel and capital needed on location. We have exceeded our own targets, reducing capital deployed by 20 percent, lowering maintenance costs by 35 percent and improving completion times by almost 40 percent at sites where Frac of the Future™ is employed. This superior operational efficiency turns customer well inventories into producing assets faster, lowers the cost to deliver each BOE and represents a competitive differentiator for Halliburton.

Frac of the Future™ is just one part of HALvantage,™ which is extending our competitive advantage by taking efficiency to the next level. After reinventing our delivery platform, we began working to reduce non-operating time in the field. We are implementing mobile technology to centralize and digitize internal processes, eliminate touch points and bottlenecks, and streamline operations – not just in unconventionals, but across all of our product lines and businesses.

Expanding Internationally

Halliburton is carrying its unconventionals leadership into emerging international markets, which are beginning to develop as countries strive to gain energy independence. We drilled and completed the first unconventional wells in many international markets. In countries such as Australia, Argentina, China and Saudi Arabia, we are able to leverage our established infrastructure to support emerging unconventional opportunities.

"The initiatives that have created North America's most efficient and effective delivery platform are an example of how Halliburton continually reinvents itself. Now we are refining efficiency even further, centralizing and digitizing our internal processes across all of our product lines and operations to extend the HALvantage.™"

JEFFREY A. MILLER
Executive Vice President, Chief Operating Officer and
Chief Health, Safety and Environment Officer

WHAT *DRIVES* US //

Unconventionals

WHAT *DRIVES* US //

Vision & Leadership

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
Executive 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 Executive Chairman of the Board,
EQT Corporation
(2012) (A) (B)

JOSÉ C. GRUBISICH
Chief Executive Officer,
Eldorado Brasil Celulose
(2013) (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
(2009) (B) (C)

J. LANDIS MARTIN
Founder and Managing Director,
Platte River Equity
(2005) (C) (D)

DEBRA L. REED
Chairman and Chief Executive Officer,
Sempra Energy
(2001) (B) (D)

(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

Corporate Officers

DAVID J. LESAR
Chairman of the Board, President and
Chief Executive Officer

JEFFREY A. MILLER
Executive Vice President,
Chief Operating Officer and Chief
Health, Safety and Environment Officer

MARK A. McCOLLUM
Executive Vice President and
Chief Financial Officer

LAWRENCE J. POPE
Executive Vice President of Administration
and Chief Human Resources Officer

ROBB L. VOYLES
Executive Vice President and
General Counsel

TIMOTHY J. PROBERT
Strategic Advisor to the Chief Executive Officer

JAMES S. BROWN
President, Western Hemisphere

JOE D. RAINEY
President, Eastern Hemisphere

JAMES W. FERGUSON
Senior Vice President, Deputy General Counsel
and Chief Ethics and Compliance Officer

CHRISTIAN GARCIA
Senior Vice President and
Chief Accounting Officer

MYRTLE L. JONES
Senior Vice President, Tax

CHRISTINA M. IBRAHIM
Vice President and Corporate Secretary

TIMOTHY M. MCKEON
Vice President and Treasurer

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, 2013

OR

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______ to ______

Commission File Number 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 Halliburton Company Common Stock held by nonaffiliates on June 30, 2013, determined using the per share closing price on the New York Stock Exchange Composite tape of $41.72 on that date, was approximately $38,003,000,000.

As of January 31, 2014, there were 850,866,860 shares of Halliburton Company Common Stock, $2.50 par value per share, outstanding.

Portions of the Halliburton Company Proxy Statement for our 2014 Annual Meeting of Stockholders (File No. 001-03492) are incorporated by reference into Part III of this report.

HALLIBURTON COMPANY
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For the Year Ended December 31, 2013

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, the Completion and Production segment and the 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 Production Enhancement, Cementing, Completion Tools, Halliburton Boots & Coots, Multi-Chem, and Halliburton Artificial Lift.
- our Drilling and Evaluation segment provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, drill, and optimize their well construction activities. The segment consists of Baroid, Sperry Drilling, Wireline and Perforating, Drill Bits and Services, Landmark Software and Services, Testing and Subsea, and 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 the United States, Canada, Malaysia, Singapore, and the United Kingdom.

Business strategy

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

- create a balanced portfolio of services and products supported by global infrastructure and anchored by technological innovation to further differentiate our company;
- reach a distinguished level of operational excellence that reduces costs and creates real value;
- preserve a dynamic workforce by being a preferred employer to attract, develop, and retain the best global talent; and
- uphold our strong ethical and business standards, 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 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 2013, 2012, and 2011, based on the location of services provided and products sold, 49%, 53%, and 55% 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 our geographic operations in the last three years. Because the markets for our services and products are vast and cross numerous geographic lines, it is not practicable to provide a meaningful estimate of the total number of our competitors. 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, as well as other geopolitical factors. 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 significantly impact 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 13 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 our 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 proppants, hydrochloric acid, and gels, including guar gum (a blending additive used in our hydraulic fracturing process). 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 enhance our 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 and high temperature environments, and also develops new products and processes. Our expenditures for research and development activities were $588 million in 2013, $460 million in 2012, and $401 million in 2011. We sponsored over 95% of these expenditures 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, 2013, we employed approximately 77,000 people worldwide compared to approximately 73,000 at December 31, 2012. At December 31, 2013, 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 and Item 1(a), "Risk Factors."

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. From time to time, questions arise 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, the United States Environmental Protection Agency (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 environment-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 potential 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, 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 web 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 2013, 2012, or 2011. 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 7, 2014, including all offices and positions held by each in the past five years:

Name and Age	Offices Held and Term of Office
James S. Brown (Age 59)	President, Western Hemisphere of Halliburton Company, since January 2008

Name and Age	Offices Held and Term of Office
Christian A. Garcia (Age 50)	Senior Vice President and Chief Accounting Officer of Halliburton Company, since January 2014
	Senior Vice President and Treasurer of Halliburton Company, September 2011 to December 2013
	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
Myrtle L. Jones (Age 54)	Senior Vice President, Tax of Halliburton Company, since March 2013
	Senior Managing Director of Tax and Internal Audit, Service Corporation International, February 2008 to February 2013
* David J. Lesar (Age 60)	Chairman of the Board, President, and Chief Executive Officer of Halliburton Company, since August 2000
* Mark A. McCollum (Age 54)	Executive Vice President and Chief Financial Officer of Halliburton Company, since January 2008
Timothy M. McKeon (Age 41)	Vice President and Treasurer of Halliburton Company, since January 2014
	Assistant Treasurer of Halliburton Company, September 2011 to December 2013
	Director of Finance, Drilling & Evaluation Division of Halliburton Company, February 2011 to August 2011
	Director of Treasury Operations of Halliburton Company, March 2009 to January 2011
	Senior Manager, Corporate Finance of Halliburton Company, August 2006 to February 2009
* Jeffrey A. Miller (Age 50)	Executive Vice President and Chief Operating Officer of Halliburton Company, since September 2012
	Senior Vice President, Global Business Development and Marketing of Halliburton Company, January 2011 to August 2012
	Senior Vice President, Gulf of Mexico Region of Halliburton Company, January 2010 to December 2010
	Vice President, Baroid, May 2006 to December 2009
* Lawrence J. Pope (Age 45)	Executive Vice President of Administration and Chief Human Resources Officer of Halliburton Company, since January 2008
Joe D. Rainey (Age 57)	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
* Robb L. Voyles (Age 56)	Executive Vice President and General Counsel of Halliburton Company, since January 2014
	Senior Vice President, Law of Halliburton Company, September 2013 to December 2013
	Partner, Baker Botts L.L.P., January 1989 to August 2013

* 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 there have been 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 the lease operator, BP Exploration (BP Exploration), an 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 1,800 complaints, most of which are alleged class-actions, involving pollution damage claims and at least eight personal injury lawsuits involving four decedents and at least 10 allegedly injured persons who were on the drilling rig at the time of the incident. At least six additional lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Other defendants in the lawsuits have filed claims against us seeking subrogation, indemnification, including with respect to liabilities under the Oil Pollution Act of 1990 (OPA), contribution and direct damages, and alleging negligence, gross negligence, fraudulent conduct, willful misconduct, and fraudulent concealment. See Note 8 to the consolidated financial statements. Additional lawsuits may be filed against us, including civil actions under federal statutes and regulations, as well as criminal and civil actions under 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, several regulatory agencies and others have investigated or are investigating the cause of the explosion, fire, and resulting oil spill. Reports issued as a result of those investigations have been critical of BP, Transocean, and us, among others. For example, one or more of those reports have concluded that primary cement failure was a direct cause of the blowout, cement testing performed by an independent laboratory “strongly suggests” that the foam cement slurry used on the Macondo well was unstable, and that numerous other oversights and factors caused or contributed to the cause of the incident, including BP's failure to run a cement bond log, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, natural gas, or fluid into the well was occurring, communication failures among BP, Transocean, and us, and flawed decisions relating to the design, construction, and testing of barriers critical to the temporary abandonment of the well.

In October 2011, the Bureau of Safety and Environmental Enforcement (BSEE) issued a notification of Incidents of Noncompliance (INCs) to us for allegedly violating federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the Macondo well under control, the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico, and 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 the Interior Board of Land Appeals (IBLA). In January 2012, the IBLA, in response to our and the BSEE's joint request, suspended the appeal pending certain proceedings in the multi-district litigation (MDL) trial. Once the MDL court issues a final decision in the trial, we expect 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.

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. BP Exploration, in connection with filing its claims with respect to the MDL proceeding, 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 proceeding. 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. We may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies.

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.

We are currently unable to fully 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 orders and rulings of the court that impact the MDL, the results of the MDL trial, the effect that the settlements between BP and the Plaintiffs' Steering Committee (PSC) in the MDL and other settlements may have on claims against us, or whether we might settle with one or more of the parties to any lawsuit or investigation. The first two phases of the MDL trial have concluded, and the MDL court could begin issuing rulings at any time. A determination that the performance of our services on the Deepwater Horizon constituted gross negligence could result in substantial liability to the numerous plaintiffs for punitive damages and potentially to BP with respect to its direct claims against us.

As of December 31, 2013, our loss contingency reserve for the Macondo well incident, relating to the MDL, remained at $1.3 billion, which represents a loss contingency that is probable and for which a reasonable estimate of loss can be made. We have participated in intermittent discussions with the PSC regarding the potential for a settlement that would resolve a substantial portion of the claims pending in the MDL trial. BP, however, has not participated in any recent settlement discussions with us.

Reaching a settlement involves a complex process, and there can be no assurance as to whether or when we may complete a settlement. In addition, the settlement discussions we have had to date do not cover all parties and claims relating to the Macondo well incident. Accordingly, there are additional loss contingencies relating to the Macondo well incident that are reasonably possible but for which we cannot make a reasonable estimate. Given the numerous potential developments relating to the MDL and other lawsuits and investigations, which could occur at any time, we may adjust our estimated loss contingency reserve in the future. Liabilities arising out of the Macondo well incident 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.

The Macondo well incident and the subsequent oil spill resulted in offshore drilling delays, temporary drilling bans, and increased federal regulation of our and our customers' operations, and more regulations and delays are possible. For example, the BSEE has:

- issued regulations that provide revised casing and cementing requirements, including integrity testing standards, that mandate independent third-party verifications, that impose blowout preventer capability, testing, and documentation obligations, and that outline standards for specific well control training for deepwater operations, among other requirements;
- issued revised regulations in 2013 to require, among other things, increased employee involvement in certain safety measures and third-party audits of operators' safety and environmental management systems;
- proposed stricter requirements for subsea drilling production equipment;
- stated that it intends to propose new standards for the design and maintenance of blowout preventers; and
- stated that it, together with the Bureau of Ocean Energy Management, is drafting new standards governing drilling in the Arctic.

In addition, the BSEE contends 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.

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 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 have agreements with certain customers that require them to indemnify us 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 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 any 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, risk of government actions, and cyber attacks that could have a material adverse effect on our business, 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 business, 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, Angola, Argentina, 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, consolidated results of operations, and consolidated financial condition.

Our operations are also subject to the risk of cyber attacks. If our systems for protecting against cybersecurity risks prove not to be sufficient, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data, having our business operations interrupted, and increased costs to prevent, respond to, or mitigate cybersecurity attacks. These risks could have a material adverse effect on our business, 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, violations of which could have a material adverse effect on our business, 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 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, consolidated results of operations, and consolidated financial condition. 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, 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 effect on our business and 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.

The adoption of any future federal, state, or local 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. Various federal legislative and regulatory initiatives have been undertaken which could result in additional requirements or restrictions being imposed on hydraulic fracturing operations. For example, the Department of Interior has issued proposed regulations that would apply to hydraulic fracturing operations on wells that are subject to federal oil and gas leases and that would impose requirements regarding the disclosure of chemicals used in the hydraulic fracturing process as well as requirements to obtain certain federal approvals before proceeding with hydraulic fracturing at a well site. These regulations, if adopted, would 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 require additional disclosure regarding chemicals used in the hydraulic fracturing process but that generally include protections for proprietary information. Legislation and/or regulations are being considered at the state and local level 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.

The adoption of any future federal, state, local, 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.

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. 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.

Failure on our part to comply with, and the costs of compliance with, applicable health, safety, and 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 health, safety, and 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. Applicable regulatory 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.

These and other requirements generally are becoming increasingly strict. Sanctions for failure to comply with the 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 regulatory compliance, including compliance with changes in or expansion of applicable regulatory 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 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.

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 business, 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 business, 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 the 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 business, consolidated results of operations, and consolidated financial condition.

Our business is directly affected by changes in capital expenditures by our customers, and reductions in their capital spending could reduce demand for our services and products and have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition. Some of the items that may impact our customer's capital spending include:

- oil and natural gas prices, including volatility of oil and natural gas prices and expectations regarding future prices;
- the inability of our customers to access capital on economically advantageous terms;
- the consolidation of our customers;
- customer personnel changes; and
- adverse developments in the business or operations of our customers, including write-downs of reserves and borrowing base reductions under customer credit facilities.

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. Some experts believe global climate change could increase the frequency and severity of extreme weather conditions. Repercussions of severe or unseasonable 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;
- decreases in demand for natural gas during unseasonably warm winters; and
- loss of productivity.

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. 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 non-traded 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. In addition, we may accumulate cash in foreign jurisdictions that may be subject to taxation if repatriated to the United States. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations" and Note 9 to the Consolidated Financial Statements, "Income Taxes."

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 the market, customer requirements, competitive pressures, and technology trends, 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 the market, customer requirements, competitive pressures, and technology trends, our business and consolidated results of operations could be materially and adversely affected, and the value of our intellectual property may be reduced. Likewise, if our proprietary technologies, equipment, 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.

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, the foreign currency exchange rate, actions of the Venezuelan government, and general economic conditions such as continued inflation and future customer payments and spending. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations - International operations - Venezuela."

Some of our customers require bids for contracts in the form of long-term, fixed pricing 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.

Some of our customers, primarily NOCs, may require bids for contracts in the form of long-term, fixed pricing contracts that may require us to provide integrated project management services outside our normal discrete business to act as project managers as well as service providers, and may require us to assume additional risks associated with cost over-runs. These customers may provide us with inaccurate information in relation to their reserves, which is a subjective process that involves location and volume estimation, that may result in cost over-runs, 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 issues may also result in cost over-runs, delays, and project losses.

Providing services on an integrated basis may also require us to assume additional risks associated with operating cost inflation, labor availability and productivity, supplier pricing and performance, and potential claims for liquidated damages. We rely on third-party subcontractors and equipment providers to assist us with the completion of these types of contracts. To the extent that we cannot engage subcontractors or acquire equipment or materials in a timely manner and on reasonable terms, our ability to complete a project in accordance with stated deadlines 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.

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

Raw materials essential to our business are normally readily available. High levels of demand for, or shortage of, raw materials, such as proppants, hydrochloric acid, and gels, including guar gum, 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.

Our acquisitions, dispositions, and investments may not result in anticipated benefits and may present risks not originally contemplated, 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 (but may not) 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 or provide an adequate return of capital or other anticipated benefits;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence conducted 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.

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.

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.

Item 1(b). Unresolved Staff Comments.

None.

Item 2. Properties.

We own or lease numerous properties in domestic and foreign locations. Our principal properties include manufacturing facilities, research and development laboratories, technology centers, and corporate offices. All of our owned properties are unencumbered.

The following locations represent our major facilities by segment:

Completion and Production segment:	Arbroath, United Kingdom Johor, Malaysia Lafayette, Louisiana Singapore, Singapore Stavanger, Norway Tianjin, China
Drilling and Evaluation segment:	Alvarado, Texas Nisku, Canada Singapore, Singapore The Woodlands, Texas
Shared/corporate facilities:	Al-Khobar, Saudi Arabia Carrollton, Texas Denver, Colorado Dubai, United Arab Emirates Duncan, Oklahoma Houston, Texas Kuala Lumpur, Malaysia Panama City, Panama Pune, India Rio de Janeiro, Brazil San Antonio, Texas

In addition, we have 179 international and 124 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.

Information related to Item 3. Legal Proceedings is included in Note 8 to the consolidated financial statements on page 55 of this annual report.

Item 4. Mine Safety Disclosures.

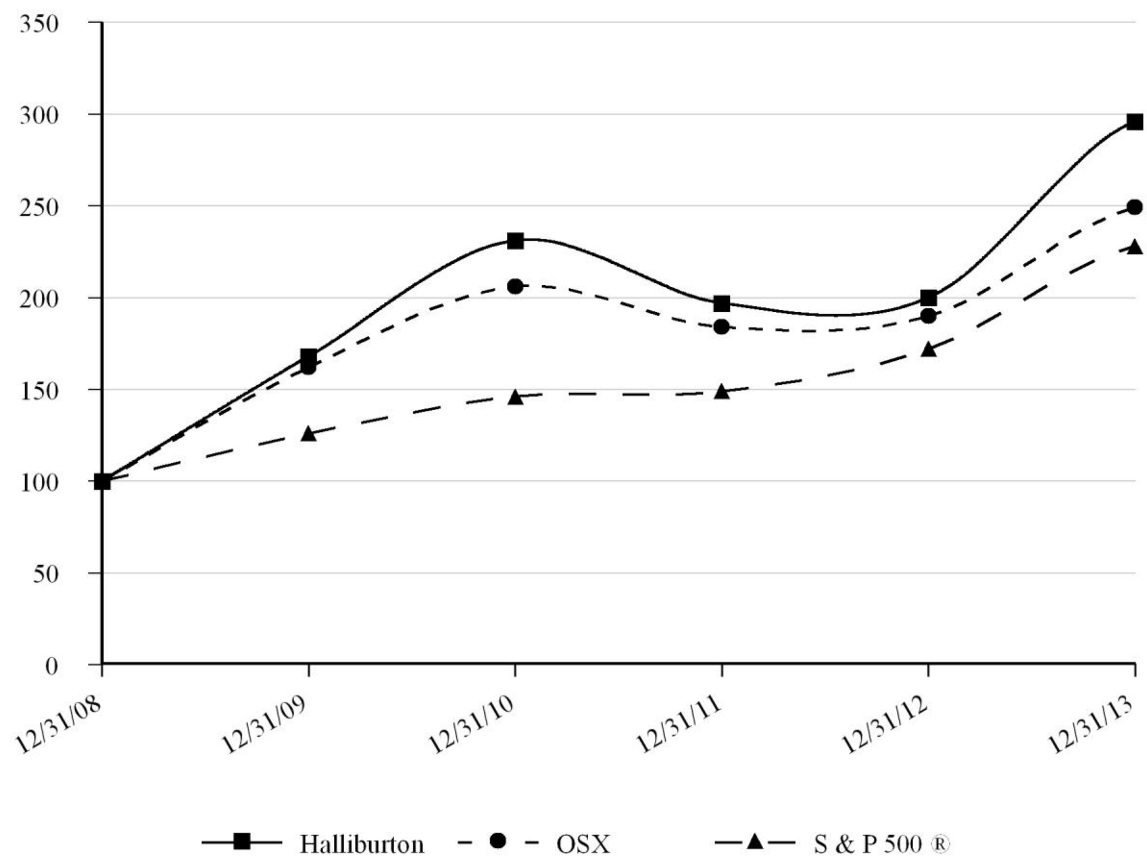
Our barite and bentonite mining operations, in support of our fluid services business, are subject to regulation by the federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act 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 74 of this annual report. Quarterly cash dividends on our common stock, which were paid in March, June, September, and December of each year, were $0.09 per share throughout 2012, $0.125 per share for the first three quarters of 2013, and $0.15 per share in the fourth quarter of 2013. The declaration and payment of future dividends 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. Subject to Board of Directors approval, our intention is to pay dividends representing at least 15% to 20% of our net income on an annual basis.

The following graph and table compare total shareholder return on our common stock for the five-year period ended December 31, 2013, with the Philadelphia Oil Service Index (OSX) and the Standard & Poor's 500 ® Index over the same period. This comparison assumes the investment of $100 on December 31, 2008, and the reinvestment of all dividends. The shareholder return set forth is not necessarily indicative of future performance.



		December 31				
	2008	2009	2010	2011	2012	2013
Halliburton	$ 100.00	$ 168.12	$ 230.75	$ 196.85	$ 200.13	$ 296.19
Philadelphia Oil Service Index (OSX)	100.00	162.15	205.80	184.09	189.86	249.32
Standard & Poor's 500 ® Index	100.00	126.46	145.51	148.59	172.37	228.19

At January 31, 2014, there were 14,454 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, 2013.

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 (b)	Maximum Number (or Approximate Dollar Value) of Shares that may yet be Purchased Under the Program (b)
October 1 - 31	73,993	$49.96	—	$1,693,971,527
November 1 - 30	80,870	$53.43	—	$1,693,971,527
December 1 - 31	140,739	$50.41	—	$1,693,971,527
Total	295,602	$51.12	—	

(a) All of the 295,602 shares purchased during the three-month period ended December 31, 2013 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 stock.

(b) Our Board of Directors has authorized a plan to repurchase our common stock from time to time. During the fourth quarter of 2013, 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 73 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 20 through 38 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 37 of this annual report and Note 13 to the consolidated financial statements on page 68 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, 2013 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, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

See page 39 for Management's Report on Internal Control Over Financial Reporting and page 40 for Report of Independent Registered Public Accounting Firm on its assessment of our internal control over financial reporting.

Item 9(b). Other Information.

None.

EXECUTIVE OVERVIEW

Financial results

During 2013, we produced revenue of $29.4 billion and operating income of $3.1 billion, reflecting an operating margin of 11%. Revenue increased $0.9 billion, or 3%, from 2012, mainly due to increased activity in all of our international regions and the Gulf of Mexico. We set new revenue records this year in all of our international regions and in both of our divisions. Additionally, during 2013, our revenue outside of North America comprised 48% of consolidated revenue. The percentage of our revenue that relates to our international operations has been steadily increasing and is representative of our ongoing strategy to grow our international business and balance our geographic mix. Our increase in international activity and revenue was partially offset by lower activity levels and pricing pressure in the United States land market, primarily for production enhancement services. Operating income in 2013 was negatively impacted by a $1.0 billion, pre-tax, Macondo-related loss contingency, as compared to a $300 million, pre-tax, Macondo-related loss contingency in 2012.

Business outlook

We continue to believe in the strength of the long-term fundamentals of our business. Energy demand is expected to increase over the long term driven by economic growth in developing countries despite current underlying downside risks in the industry, such as sluggish growth in developed countries and uncertainties associated with geopolitical tensions in the Middle East and North Africa. Furthermore, development of new resources is expected to be more complex, resulting in higher service intensity as our customers move increasingly to horizontal drilling.

In North America, we continue to experience pricing pressures, which have impacted our margins. However, we believe the current environment and our focus on efficient cost structure continues to favor us. As a result of the industry's activity shift from natural gas plays to oil and liquids-rich basins, operators have been allocating their budgets to basins with better economics. In addition, we are observing a meaningful switch to multi-well pad activity among our customer base, which is resulting in increased drilling and completion service efficiency. We believe the incremental efficiency gains provided by multi-well pad drilling will enable us to leverage our operational scale and expertise.

Outside of North America, both revenue and operating income increased in 2013 compared to 2012. We believe that international growth in 2014 will come from volume increases as we deploy resources on our recent contract wins and new projects, continued improvement in markets where we have made strategic investments, the introduction of new technology, and increased pricing and cost recovery on select contracts. We also believe that international unconventional oil and natural gas, mature field, and deepwater projects will contribute to activity improvements over the long term, and we plan to leverage our extensive experience in North America to capitalize on these opportunities. Consistent with our long-term strategy to grow our operations outside of North America, we also expect to continue to invest in capital equipment for our international operations. In Latin America, we expect 2014 to be a challenging year due to a decline in existing integrated project management work in Mexico as we begin transitioning to newly-tendered projects, and due to reduced activity in Brazil. However, this does not change our long-term outlook for Latin America, which we expect to contribute significantly to our future growth and profitability.

We continued to execute several key initiatives in 2013. These initiatives included increasing manufacturing capacity in the Eastern Hemisphere and repositioning our service delivery platform to lower our delivery costs. We plan to continue to invest in these initiatives in 2014. In addition, we plan to continue executing the following strategies:

- focusing on unconventional plays, mature fields, 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 infrastructure to maximize growth opportunities. To that end, we are continuing to push our technology and manufacturing capacity, as well as our supply chain, closer to our customers in the Eastern Hemisphere;
- improving working capital, and managing our balance sheet to maximize our financial flexibility. We are deploying a global project to improve service delivery that we expect to result in, among other things, additional investments in our systems and significant improvements to our current order-to-cash and purchase-to-pay processes;
- growing our international revenues and margins by continuing to invest capital and resources in these markets;
- improving our North America margins by leveraging technologies and reducing costs through more efficient operations;
- continuing to seek ways to be one of the most cost efficient service providers in the industry by maintaining capital discipline and leveraging our scale and breadth of operations; and
- expanding our business with national oil companies.

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

Financial markets, liquidity, and capital resources

We believe we have invested our cash balances conservatively and secured sufficient financing to help mitigate any near-term negative impact on our operations from adverse market conditions. For additional information, see “Liquidity and Capital Resources” and “Business Environment and Results of Operations.”

LIQUIDITY AND CAPITAL RESOURCES

We ended 2013 with cash and equivalents of $2.4 billion compared to $2.5 billion at December 31, 2012. Additionally, at December 31, 2013, we held $373 million of investments in fixed income securities compared to $398 million at December 31, 2012, These securities are reflected in "Other current assets" and "Other assets" in our consolidated balance sheets. As of December 31, 2013, approximately $306 million of the $2.4 billion of cash and equivalents was held by our foreign subsidiaries, and would be subject to United States tax if repatriated. However, our intent is to permanently reinvest these funds outside of the United States and our current plans do not suggest a need to repatriate them to fund our United States operations.

Significant sources and uses of cash

Cash flows from operating activities were $4.4 billion in 2013.

In the third quarter of 2013, we issued $3.0 billion aggregate principal amount of senior notes and used the net proceeds, along with cash on hand, to fund the repurchase of approximately 68 million shares of our common stock at an aggregate cost of $3.3 billion pursuant to a modified Dutch auction cash tender offer. During 2013, we repurchased approximately 93 million shares of our common stock under our share repurchase program at a total cost of approximately $4.4 billion.

Capital expenditures were $2.9 billion in 2013. The capital expenditures in 2013 were predominantly made in our Production Enhancement, Sperry Drilling, Boots and Coots, Wireline and Perforating, and Cementing product service lines. We have also invested additional working capital to support the growth of our business.

We paid $465 million of dividends to our shareholders in 2013. We increased our quarterly dividend rate by $0.035 per share in the first quarter of 2013 and an additional $0.025 per share in the fourth quarter of 2013. Our current quarterly dividend rate is $0.15 per share, or approximately $129 million per quarter, which represents a 67% increase over the quarterly dividend rate during 2012.

During 2013, we sold $241 million of property, plant, and equipment.

Our primary components of net working capital (receivables, inventories and accounts payable) increased during the year by a net $229 million, primarily due to increased business activity.

In the first quarter of 2013, we made a $219 million payment under a guarantee we issued for the Barracuda-Caratinga project.

In the second quarter of 2013, we made a $172 million earn-out payment related to a prior year acquisition due to significantly better than expected operating performance.

Future sources and uses of cash

Capital spending for 2014 is currently expected to be approximately $3.0 billion. The capital expenditures plan for 2014 is primarily directed towards our Production Enhancement, Sperry Drilling, Cementing, Boots & Coots, and Wireline and Perforating product service lines, with an increasing amount dedicated to our international operations.

Subject to Board of Directors approval, our intention is to pay dividends representing at least 15% to 20% of our net income on an annual basis. We have approximately $1.7 billion remaining available under our share repurchase authorization, which may be used for open market and other share repurchases.

During 2013, the Congressional Joint Committee on Taxation approved a $135 million income tax refund, excluding interest, to us for agreed upon tax items for the tax years 2003 through 2009. We expect to receive the refund in 2014.

In the third quarter of 2013, we were awarded $105 million by an arbitrator regarding amounts owed by KBR, Inc. (KBR) related to our Tax Sharing Agreement with KBR. KBR is contesting the award and, although the arbitrator recently issued a supplemental report that reaffirmed the original award, there is uncertainty as to the ultimate timing and amount of any payment. See Note 7 to the consolidated financial statements for further information.

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 significant operations.

We had $209 million of gross unrecognized tax benefits at December 31, 2013, of which we estimate $146 million may require a cash payment. We estimate that $141 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 any amounts will ultimately be settled and paid.

Contractual obligations

The following table summarizes our significant contractual obligations and other long-term liabilities as of December 31, 2013:

	Payments Due						
Millions of dollars	2014	2015	2016	2017	2018	Thereafter	Total
Long-term debt	$ —	$ —	$ 600	$ 45	$ 800	$ 6,389	$ 7,834
Interest on debt (a)	362	365	376	385	398	6,422	8,308
Operating leases	282	215	156	83	56	154	946
Purchase obligations (b)	2,382	450	315	225	76	96	3,544
Other long-term liabilities (c)	39	3	3	3	2	4	54
Total	$ 3,065	$ 1,033	$ 1,450	$ 741	$ 1,332	$ 13,065	$ 20,686

(a) Interest on debt includes 83 years of interest on $300 million of debentures at 7.6% interest that become due in 2096.
(b) Amount in 2014 primarily represents certain purchase orders for goods and services utilized in the ordinary course of our business.
(c) Includes capital lease obligations and pension funding obligations. Amounts for pension funding obligations, which include international plans and are based on assumptions that are subject to change, are only included for 2014 as we are currently not able to reasonably estimate our contributions for years after 2014.

Other factors affecting liquidity

Financial position in current market. As of December 31, 2013, we had $2.4 billion of cash and equivalents, $373 million in fixed income investments, and a total of $3.0 billion of available committed bank credit under our revolving credit facility. Reflecting the growth of our company, we executed an amendment to our revolving credit facility during 2013, which increased the capacity from $2.0 billion to $3.0 billion and extended the maturity to 2018. 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 capital expenditures, working capital investments, and dividends, if any, in 2014 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 in Note 8 to the consolidated financial statements, 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 $2.1 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2013. 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 as well as unsettled political conditions. 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. See "Business Environment and Results of Operations – International operations – Venezuela" for further discussion related to Venezuela.

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. A significant amount 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 2013, 2012, and 2011, based on the location of services provided and products sold, 49%, 53%, and 55% 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, as well as other geopolitical factors. 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 our customers. Also impacting our activity is the status of the global economy, which impacts oil and natural gas consumption.

Some of the more significant determinants of current and future spending levels of our customers 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. Additionally, due to improved drilling and completion efficiencies as more of our customers move to multi-well pad drilling, our financial performance is impacted by well count in the North America market.

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

	2013	2012	2011
Oil price - WTI (1)	$ 97.99	$ 94.15	$ 95.13
Oil price - Brent (1)	108.71	111.60	111.53
Natural gas price - Henry Hub (2)	3.73	2.81	4.09

(1) Oil price measured in dollars per barrel
(2) Natural gas price measured in dollars per thousand cubic feet, or Mcf

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

Land vs. Offshore	2013	2012	2011
United States:			
Land	1,705	1,872	1,843
Offshore (incl. Gulf of Mexico)	56	47	32
Total	1,761	1,919	1,875
Canada:			
Land	352	363	422
Offshore	2	1	1
Total	354	364	423
International (excluding Canada):			
Land	978	931	863
Offshore	318	303	304
Total	1,296	1,234	1,167
Worldwide total	3,411	3,517	3,465
Land total	3,035	3,166	3,128
Offshore total	376	351	337

Oil vs. Natural Gas	2013	2012	2011
United States (incl. Gulf of Mexico):			
Oil	1,375	1,359	984
Natural gas	386	560	891
Total	1,761	1,919	1,875
Canada:			
Oil	234	261	282
Natural gas	120	103	141
Total	354	364	423
International (excluding Canada):			
Oil	1,029	984	918
Natural gas	267	250	249
Total	1,296	1,234	1,167
Worldwide total	3,411	3,517	3,465
Oil total	2,638	2,604	2,184
Natural gas total	773	913	1,281

Drilling Type	2013	2012	2011
United States (incl. Gulf of Mexico):			
Horizontal	1,102	1,151	1,074
Vertical	435	552	571
Directional	224	216	230
Total	1,761	1,919	1,875

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, while the opposite is true for higher oil and natural gas prices.

WTI oil prices, which generally influence customer spending in North America, fluctuated throughout 2013, ranging from a high of $111 per barrel in September to a low of $87 per barrel in April. Outside of North America, customer spending is heavily influenced by Brent oil prices, which fluctuated during 2013 from a high of $119 per barrel in February to a low of $97 per barrel in April. Oil prices were affected by production disruptions in Libya, Nigeria, and Iraq, offset by growing output by certain OPEC members. Global oil demand growth appears to have gradually gained momentum in the past 18 months and the International Energy Agency's January 2014 "Oil Market Report" forecasts a 1% increase in global petroleum demand from 2013 levels. This is driven by economic recovery in the developed world and an increase in all regions except for Europe, which is forecasted to remain flat.

Henry Hub natural gas prices in the United States have increased approximately 33% from 2012 as a result of an increase in storage withdrawals due to cooler temperatures in the early part and December of 2013. This, coupled with higher natural gas demand for industrial purposes, resulted in higher natural gas prices. Natural gas prices during 2013 ranged from a low of $3.08 per Mcf in January to a high of $4.52 per Mcf in December. The United States Energy Information Administration (EIA) January 2014 "Short Term Energy Outlook" forecast projects Henry Hub natural gas prices to average $3.89 per Mcf in 2014 compared to $3.73 per Mcf in 2013. Over the long term, the EIA expects natural gas consumption in the power sector to increase to offset the retirement of coal power plants.

There has been an increase in natural gas prices over the past year and the global economy continues to recover. 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. During 2013, the average natural gas-directed rig count in North America fell by 157 rigs, or 24%, from 2012 levels. The curtailment of natural gas drilling activity along with an influx of stimulation equipment into the industry has resulted in overcapacity and pricing pressure for hydraulic fracturing and other services. Despite the decreased rig count in the United States as compared to 2012, drilling efficiencies and the trend toward multi-well pads are driving a more robust well count. Additionally, operators have been, in some cases, increasing the numbers of hydraulic fracturing stages on horizontal wells.

We expect United States land rig count to modestly increase from 2013 levels, driven primarily by the continued shift to horizontal rigs in the Permian Basin. We are seeing higher well efficiencies due to increased pad drilling, more 24-hour operations, rig fleet upgrades, and significant advancements in drilling and completion technologies. In 2013, we saw average drilling days per horizontal well drop approximately 14% compared to 2012 and we anticipate continued efficiency improvements in 2014. We believe this continued shift towards efficiency will bode well for us in the coming years. In the long run, we believe the shift to unconventional oil and liquids-rich basins in North America will continue to drive increased service intensity and will require higher demand in fluid chemistry and other technologies required for these complex reservoirs which will have beneficial implications for our operations.

In the Gulf of Mexico, improvements in the performance of many of our product service lines was due to a 19% increase in the offshore rig count from 2012, in addition to the efficiencies and integrated solutions we offer that save our customers time and enhance productivity. Over the long term, the continued growth in the Gulf of Mexico is dependent on, among other things, governmental approvals for permits, our customers' actions, and new deepwater rigs entering the market.

International operations

The industry experienced steady volume increases during 2013, with the average international rig count improving 5% over 2012 levels. These volume increases have led to an absorption of equipment supply and we are seeing sporadic opportunities for price improvements in select geographies. We anticipate moderate margin improvements and gradual activity increases in the Eastern Hemisphere, although the operator spending outlook could be impacted by ongoing macroeconomic concerns. We believe 2014 will be a challenging year for Latin America, primarily in Brazil and Mexico. Over the long term, however, we expect both of these countries to be strong contributors to our growth and profitability.

We believe that international growth in 2014 will come from volume increases as we deploy resources on our recent contract and project wins, continued improvement in certain markets where we have made strategic investments, introduction of new technology, and increased pricing and cost recovery on select contracts. We also believe that international unconventional oil and natural gas, mature field, and deepwater projects will contribute to activity improvements over the long term, and we plan to leverage our extensive experience in North America to optimize these opportunities. Consistent with our long-term strategy to grow our operations outside of North America, we also expect to continue to invest in capital equipment for our international operations.

Venezuela. As of December 31, 2013, our total net investment in Venezuela was approximately $411 million, including net monetary assets of $124 million denominated in Bolívares. Also, at December 31, 2013 we had $192 million of surety bond guarantees outstanding relating to our Venezuelan operations.

We continue to experience delays in collecting payment on our receivables from our primary customer in Venezuela. These receivables are not disputed, and we have not historically had material write-offs relating to this customer. Additionally, we routinely monitor the financial stability of our customers. Our total outstanding trade receivables in Venezuela were $486 million, or approximately 8% of our gross trade receivables, as of December 31, 2013, compared to $491 million, or approximately 9% of our gross trade receivables, as of December 31, 2012. Of the $486 million of receivables in Venezuela as of December 31, 2013, $183 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets. Of the $491 million receivables in Venezuela as of December 31, 2012, $143 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets.

In February 2013, the Venezuelan government devalued the Bolívar, from the preexisting exchange rate of 4.3 Bolívares per United States dollar to 6.3 Bolívares per United States dollar, resulting in us incurring a foreign currency loss. The net foreign currency impact of Bolívar activity in the first quarter of 2013 was not material, although further devaluation of the Bolívar could impact our operations. For additional information, see Part I, Item 1(a), “Risk Factors” in this Form 10-K.

RESULTS OF OPERATIONS IN 2013 COMPARED TO 2012

REVENUE: *Millions of dollars*	2013	2012	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 17,506	$ 17,380	$ 126	1 %
Drilling and Evaluation	11,896	11,123	773	7
Total revenue	$ 29,402	$ 28,503	$ 899	3 %
By geographic region:				
Completion and Production:				
North America	$ 11,417	$ 12,157	$ (740)	(6)%
Latin America	1,586	1,415	171	12
Europe/Africa/CIS	2,391	2,099	292	14
Middle East/Asia	2,112	1,709	403	24
Total	17,506	17,380	126	1
Drilling and Evaluation:				
North America	3,795	3,847	(52)	(1)
Latin America	2,323	2,279	44	2
Europe/Africa/CIS	2,834	2,411	423	18
Middle East/Asia	2,944	2,586	358	14
Total	11,896	11,123	773	7
Total revenue by region:				
North America	15,212	16,004	(792)	(5)
Latin America	3,909	3,694	215	6
Europe/Africa/CIS	5,225	4,510	715	16
Middle East/Asia	5,056	4,295	761	18

OPERATING INCOME: *Millions of dollars*	2013	2012	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 2,875	$ 3,144	$ (269)	(9)%
Drilling and Evaluation	1,770	1,675	95	6
Corporate and other	(1,507)	(660)	(847)	128
Total operating income	$ 3,138	$ 4,159	$ (1,021)	(25)%
By geographic region:				
Completion and Production:				
North America	$ 1,916	$ 2,260	$ (344)	(15)%
Latin America	211	206	5	2
Europe/Africa/CIS	356	347	9	3
Middle East/Asia	392	331	61	18
Total	2,875	3,144	(269)	(9)
Drilling and Evaluation:				
North America	656	680	(24)	(4)
Latin America	307	393	(86)	(22)
Europe/Africa/CIS	334	246	88	36
Middle East/Asia	473	356	117	33
Total	1,770	1,675	95	6
Total operating income by region (excluding Corporate and other):				
North America	2,572	2,940	(368)	(13)
Latin America	518	599	(81)	(14)
Europe/Africa/CIS	690	593	97	16
Middle East/Asia	865	687	178	26

Consolidated revenue in 2013 increased 3% compared to 2012, primarily driven by activity growth across all international regions. This was partially offset by lower activity levels and pricing pressure in the United States land market. Revenue outside of North America was 48% of consolidated revenue in 2013 and 44% of consolidated revenue in 2012.

The $1.0 billion decrease in consolidated operating income compared to 2012 was primarily related to Macondo-related charges. Operating income in 2013 was impacted by the following pre-tax items: a $1.0 billion Macondo-related loss contingency, $92 million of restructuring charges related to severance and asset write-offs, and a $55 million charge related to a charitable contribution to the National Fish and Wildlife Foundation, partially offset by a $28 million value-added tax refund receivable in Brazil. Operating income in 2012 was impacted by the following pre-tax items: a $300 million Macondo-related loss contingency, along with a $48 million charge related to an earn-out adjustment due to significantly better than expected performance of a past acquisition, partially offset by a $20 million gain related to the settlement of a patent infringement lawsuit.

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

Completion and Production revenue increased slightly compared to 2012 due to strong international growth, which was partially offset by a decline in North America activity. North America revenue decreased 6%, primarily due to pricing pressures in the United States hydraulic fracturing market and lower activity in Canada. Latin America revenue was up 12% due to increased completion tools sales in Brazil and higher activity in most product service lines in Mexico and Argentina. Europe/Africa/CIS revenue grew 14%, driven by strong demand for cementing services in Norway, West Africa, and Russia and completion tools throughout the region. Middle East/Asia revenue improved 24% due to higher activity in most product service lines in Saudi Arabia, Australia, Indonesia, and China, increased completion tools sales in Malaysia, and higher demand for cementing services in Thailand. Revenue outside of North America was 35% of total segment revenue in 2013 and 30% of total segment revenue in 2012.

Completion and Production operating income decreased 9% compared to 2012, primarily due to the North America region, where operating income fell 15% due to pricing pressures in the United States hydraulic fracturing market and lower activity in Canada. Latin America operating income was up 2% as a result of higher demand for cementing services in Mexico and Venezuela and production enhancement services in Argentina. Europe/Africa/CIS operating income grew 3% compared to 2012, driven by higher completion tools activity in Angola and cementing activity in Norway. Middle East/Asia operating income increased 18% due to higher activity levels in Saudi Arabia and Iraq, higher direct sales in China, and improved profitability in Indonesia.

Drilling and Evaluation revenue increased 7% compared to 2012, driven by strong results in the Eastern Hemisphere. North America revenue was essentially flat, as lower demand for drilling and wireline services was partially offset by fluids activity across the United States land market and higher activity in the Gulf of Mexico. Latin America revenue was also relatively flat, as higher demand for all product lines in Mexico and fluids throughout the region were partially offset by lower drilling services activity in Colombia and wireline activity in Brazil. Europe/Africa/CIS revenue increased 18% due to improved fluids activity in Norway and Angola and higher drilling services activity in Eurasia, Norway, Egypt, and Angola. Middle East/Asia revenue rose 14% primarily due to strong demand in Saudi Arabia and Indonesia, higher drilling activity throughout the region, and higher wireline activity in Asia Pacific. Revenue outside of North America was 68% of total segment revenue in 2013 and 65% of total segment revenue in 2012.

Drilling and Evaluation operating income improved 6% compared to 2012, as increased activity in the Eastern Hemisphere was partially offset by higher costs in Latin America. North America operating income was down 4% from 2012, as a reduction in drilling and wireline services was partially offset by demand for fluids and consulting and project management. Latin America operating income declined 22% due to higher costs in Brazil and Venezuela and lower activity in Colombia. The Europe/Africa/CIS region operating income grew 36%, driven by fluids activity in Angola and Norway and drilling services in Eurasia. Middle East/Asia operating income increased 33% as a result of higher activity in Iraq, Indonesia, and Malaysia.

Corporate and other expenses were $1.5 billion in 2013 compared to $660 million in 2012. The significant increase was primarily due to a $1.0 billion Macondo-related loss contingency that was recorded in the first quarter of 2013, compared to a $300 million Macondo-related loss contingency recorded in the first quarter of 2012. Additionally, a $55 million charitable contribution to the National Fish and Wildlife Foundation was expensed in the second quarter of 2013, reflecting our commitment to making a positive environmental impact in our local communities.

NONOPERATING ITEMS

Effective tax rate. Our effective tax rate on continuing operations was 23.5% for 2013 and 32.3% for 2012. The 2013 effective tax rate on continuing operations was positively impacted by several items during the year, including federal tax benefits of approximately $50 million due to the reinstatement of certain tax benefits and credits related to the first quarter enactment of the American Taxpayer Relief Act of 2012. Also contributing to the lower tax rate in 2013 was a $1.0 billion loss contingency related to the Macondo well incident, which was tax-effected at the United States statutory rate, as well as some favorable tax items in Latin America in the fourth quarter. Additionally, our effective tax rate was positively impacted by lower tax rates in certain foreign jurisdictions, as we continue to reposition our technology, supply chain, and manufacturing infrastructure to more effectively serve our customers internationally.

RESULTS OF OPERATIONS IN 2012 COMPARED TO 2011

REVENUE: *Millions of dollars*	2012	2011	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 17,380	$ 15,143	$ 2,237	15%
Drilling and Evaluation	11,123	9,686	1,437	15
Total revenue	$ 28,503	$ 24,829	$ 3,674	15%
By geographic region:				
Completion and Production:				
North America	$ 12,157	$ 10,907	$ 1,250	11%
Latin America	1,415	1,117	298	27
Europe/Africa/CIS	2,099	1,746	353	20
Middle East/Asia	1,709	1,373	336	24
Total	17,380	15,143	2,237	15
Drilling and Evaluation:				
North America	3,847	3,506	341	10
Latin America	2,279	1,865	414	22
Europe/Africa/CIS	2,411	2,210	201	9
Middle East/Asia	2,586	2,105	481	23
Total	11,123	9,686	1,437	15
Total revenue by region:				
North America	16,004	14,413	1,591	11
Latin America	3,694	2,982	712	24
Europe/Africa/CIS	4,510	3,956	554	14
Middle East/Asia	4,295	3,478	817	23

OPERATING INCOME: *Millions of dollars*	2012	2011	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 3,144	$ 3,733	$ (589)	(16)%
Drilling and Evaluation	1,675	1,403	272	19
Corporate and other	(660)	(399)	(261)	65
Total operating income	$ 4,159	$ 4,737	$ (578)	(12)%

By geographic region:				
Completion and Production:				
North America	$ 2,260	$ 3,341	$ (1,081)	(32)%
Latin America	206	159	47	30
Europe/Africa/CIS	347	48	299	623
Middle East/Asia	331	185	146	79
Total	3,144	3,733	(589)	(16)
Drilling and Evaluation:				
North America	680	641	39	6
Latin America	393	305	88	29
Europe/Africa/CIS	246	191	55	29
Middle East/Asia	356	266	90	34
Total	1,675	1,403	272	19
Total operating income by region (excluding Corporate and other):				
North America	2,940	3,982	(1,042)	(26)
Latin America	599	464	135	29
Europe/Africa/CIS	593	239	354	148
Middle East/Asia	687	451	236	52

The 15% increase in consolidated revenue in 2012 compared to 2011 was primarily due to higher activity in Latin America, Middle East/Asia, and North America. On a consolidated basis, all product service lines experienced revenue growth from 2011. Revenue outside of North America was 44% of consolidated revenue in 2012 and 42% of consolidated revenue in 2011.

The 12% decrease in consolidated operating income compared to 2011 was mainly due to higher costs, particularly of guar gum, and pricing pressure for production enhancement services in North America. Operating income in 2012 was negatively impacted by a $300 million, pre-tax, loss contingency related to the Macondo well incident reflected in Corporate and other expenses. Additionally, our results were impacted by a $48 million, pre-tax, charge related to an earn-out adjustment due to significantly better than expected performance of a past acquisition in the Latin America and North America regions as well as a $20 million, pre-tax, gain related to the settlement of a patent infringement lawsuit that was recorded in Corporate and other expense. 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, $11 million, pre-tax, of employee separation costs in the Eastern Hemisphere, and a $59 million, pre-tax, charge in Libya, to reserve for certain doubtful accounts receivable and inventory. During 2012, we received $42 million related to the Libya reserve that was established in 2011 for receivables.

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

Completion and Production revenue increased in all geographic regions compared to 2011, with strong international growth. North America revenue rose 11%, primarily due to increased cementing services and completions tools sales, as well as higher activity in production enhancement from an increased demand for hydraulic fracturing in the United States. Latin America revenue increased 27% due to improved activity in most product service lines in Mexico, Brazil, and Venezuela. Europe/Africa/CIS revenue increased 20%, driven by strong demand for completion tools across the region and increased cementing services in Mozambique and Nigeria. Middle East/Asia revenue grew 24% due to higher activity in all product service lines in Australia, Malaysia, and Indonesia, partially offset by lower completion tools sales in China and decreased activity in Singapore. Revenue outside of North America was 30% of total segment revenue in 2012 and 28% of total segment revenue in 2011.

The Completion and Production segment operating income decrease compared to 2011 was primarily due to the North America region, where operating income fell $1.1 billion as a result of pricing pressure in the production enhancement product service line and rising costs, particularly related to guar gum. Latin America operating income increased 30% due to higher demand for completion tools in Mexico and Brazil, partially offset by higher costs and pricing adjustments in Argentina and Colombia. Europe/Africa/CIS operating income grew $299 million compared to 2011 due to the recovery from activity disruptions in North Africa, including collections in 2012 of $29 million from the original $36 million Libya-related reserve recognized in 2011 for certain accounts receivable and inventory. Middle East/Asia operating income increased 79% due to cost controls in Iraq, higher activity levels in Oman, and increased demand for production enhancement and cementing services in Australia.

Drilling and Evaluation revenue increased 15% compared to 2011 as drilling activity improved across all regions, especially Middle East/Asia and Latin America. North America revenue grew 10% due to increased demand for drilling fluids. Latin America revenue increased 22% due to higher demand in most product services lines in Brazil, Mexico, Venezuela, and Colombia. Europe/Africa/CIS revenue increased 9% due to improved drilling service in Tanzania, Nigeria, and the United Kingdom, partially offset by service disruptions in Algeria. Middle East/Asia revenue rose 23% primarily due to the ongoing work in Iraq and Saudi Arabia, increased activity in Malaysia, and higher wireline direct sales. Revenue outside North America was 65% of total segment revenue in 2012 and 64% of total segment revenue in 2011.

Segment operating income compared to 2011 increased 19%, primarily due to increased activity in Middle East/Asia and Latin America. North America operating income increased 6% from increased demand for drilling fluids and wireline and perforating, which offset higher consulting and project management costs. Latin America operating income grew 29% as a result of activity increases in Mexico, Venezuela, and Brazil. The Europe/Africa/CIS region operating income grew 29% due to greater activity in Nigeria and the recovery in Libya where $13 million of the original $23 million reserve from 2011 mentioned above was collected in 2012, which more than offset higher costs in Norway. Middle East/Asia operating income increased 34% mainly due to increased activity in Malaysia and Saudi Arabia.

Corporate and other expenses were $660 million in 2012 compared to $399 million in 2011. The 65% increase was primarily due to a $300 million, pre-tax, loss contingency recorded in 2012 related to the Macondo well incident as well as additional expenses in 2012 associated with strategic investments in our operating model and creating competitive advantages by repositioning our technology, supply chain, and manufacturing infrastructure. These items were partially offset by, among other things, a $20 million, pre-tax, gain recorded in 2012 related to the settlement of a patent infringement lawsuit.

NONOPERATING ITEMS

Income (loss) from discontinued operations, net increased $224 million in 2012 compared to 2011, primarily due to a $163 million charge, after-tax, recognized in 2011 for an arbitration award against our former subsidiary, KBR, relating to the Barracuda-Caratinga project, a project for which we had provided a guarantee of KBR's obligations. In 2012, we recorded an $80 million tax benefit in discontinued operations related to the $219 million payment we made to Barracuda & Caratinga Leasing Company BV under that guarantee.

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 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, integrated project management 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. 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, 2013, we have accrued an estimate of the probable and estimable costs for the resolution of some of our 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.

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. See Note 1 to the consolidated financial statements for our accounting policies related to long-lived assets and intangible assets, as well as the results of our goodwill impairment test.

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. Our acquisitions may also include contingent consideration, or earn-out provisions, which provide for additional consideration to be paid to the seller if certain future conditions are met. These earn-out provisions are estimated and recognized at fair value at the acquisition date based on projected earnings or other financial metrics over specified periods after the acquisition date. These estimates are reviewed during the specified period and adjusted based on actual results.

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 discount rate utilized in 2013 to determine the projected benefit obligation at the measurement date for our United Kingdom pension plan, which constituted 81% of our international plans' pension obligations, was 4.5%, compared to a discount rate of 4.6% utilized in 2012. The expected long-term rate of return assumption used for our United Kingdom pension plan expense was 6.5% in 2013, compared to 6.7% in 2012.

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 2013	Pension Benefit Obligation at December 31, 2013
25-basis-point decrease in discount rate	$ 1	$ 55
25-basis-point increase in discount rate	(1)	(51)
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 $32 million in 2013, $26 million in 2012, and $27 million in 2011. Included in these amounts was income from expected pension returns of $44 million in 2013, $45 million in 2012, and $47 million in 2011. Actual returns on international plan assets totaled $117 million in 2013, compared to $87 million in 2012. Our net actuarial loss, net of tax, related to international pension plans was $222 million at December 31, 2013 and $208 million at December 31, 2012. In our international plans where employees earn additional benefits for continued service, actuarial gains and losses will be recognized in operating income over a period of three 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 will be recognized in operating income over a period of 17 to 33 years, which represents the estimated average remaining lifetime of the benefit obligations. These ranges reflect varying maturity levels among the plans.

During 2013, we made contributions of $26 million to fund our international defined benefit plans. We expect to make contributions of approximately $17 million to our international defined benefit plans in 2014.

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 14 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, 2013, allowance for bad debts totaled $117 million, or 1.9% of notes and accounts receivable before the allowance. At December 31, 2012, allowance for bad debts totaled $92 million, or 1.6% 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, 2013 would have resulted in a $62 million adjustment to 2013 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 weather, inflation, labor and community disruptions, timely availability of materials, productivity, and other factors as outlined in Item 1(a), "Risk Factors." These factors can affect the accuracy of our estimates and materially impact our future reported earnings. See Note 1 to the consolidated financial statements for further information.

OFF BALANCE SHEET ARRANGEMENTS

At December 31, 2013, 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 – Contractual obligations."

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 foreign exchange contracts, foreign exchange options, 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 contracts, options, and interest rate swaps are global commercial and investment banks.

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, 2013 would result in an $89 million, pre-tax, loss for our net monetary assets denominated in currencies other than United States dollars.

With respect to interest rates sensitivity, 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 $10 million of interest charges for the year ended December 31, 2013.

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.

For further information regarding foreign currency exchange risk, interest rate risk, and credit risk, see Note 13 to the consolidated financial statements.

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 and Part I, Item 1(a), "Risk Factors."

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 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, 2013 based upon criteria set forth in the Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2013, our internal control over financial reporting is effective.

The effectiveness of Halliburton's internal control over financial reporting as of December 31, 2013 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 Chairman of the Board, President, and Chief Executive Officer	Mark A. McCollum Executive Vice President and 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, 2013 and 2012, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2013. These consolidated financial statements are the responsibility of Halliburton 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, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 7, 2014 expressed an unqualified opinion on the effectiveness of Halliburton Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 7, 2014

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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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 Halliburton 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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, 2013 and 2012, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 7, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 7, 2014

HALLIBURTON COMPANY
Consolidated Statements of Operations

	Year Ended December 31		
Millions of dollars and shares except per share data	2013	2012	2011
Revenue:			
Services	$ 22,257	$ 22,196	$ 19,692
Product sales	7,145	6,307	5,137
Total revenue	29,402	28,503	24,829
Operating costs and expenses:			
Cost of services	18,959	18,447	15,432
Cost of sales	5,972	5,322	4,379
Loss contingency for Macondo well incident	1,000	300	—
General and administrative	333	275	281
Total operating costs and expenses	26,264	24,344	20,092
Operating income	3,138	4,159	4,737
Interest expense, net of interest income of $8, $7, and $5	(331)	(298)	(263)
Other, net	(43)	(39)	(25)
Income from continuing operations before income taxes	2,764	3,822	4,449
Provision for income taxes	(648)	(1,235)	(1,439)
Income from continuing operations	2,116	2,587	3,010
Income (loss) from discontinued operations, net of income tax benefit (provision) of $1, $82, and $(18)	19	58	(166)
Net income	$ 2,135	$ 2,645	$ 2,844
Noncontrolling interest in net income of subsidiaries	(10)	(10)	(5)
Net income attributable to company	$ 2,125	$ 2,635	$ 2,839
Amounts attributable to company shareholders:			
Income from continuing operations	$ 2,106	$ 2,577	$ 3,005
Income (loss) from discontinued operations, net	19	58	(166)
Net income attributable to company	$ 2,125	$ 2,635	$ 2,839
Basic income per share attributable to company shareholders:			
Income from continuing operations	$ 2.35	$ 2.78	$ 3.27
Income (loss) from discontinued operations, net	0.02	0.07	(0.18)
Net income per share	$ 2.37	$ 2.85	$ 3.09
Diluted income per share attributable to company shareholders:			
Income from continuing operations	$ 2.33	$ 2.78	$ 3.26
Income (loss) from discontinued operations, net	0.03	0.06	(0.18)
Net income per share	$ 2.36	$ 2.84	$ 3.08
Basic weighted average common shares outstanding	898	926	918
Diluted weighted average common shares outstanding	902	928	922

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Comprehensive Income

	Year Ended December 31		
Millions of dollars	2013	2012	2011
Net income	$ 2,135	$ 2,645	$ 2,844
Other comprehensive income, net of income taxes:			
Defined benefit and other postretirement plans adjustments	—	(33)	(34)
Other	2	(3)	—
Other comprehensive income (loss), net of income taxes	2	(36)	(34)
Comprehensive income	$ 2,137	$ 2,609	$ 2,810
Comprehensive income attributable to noncontrolling interest	(10)	(10)	(4)
Comprehensive income attributable to company shareholders	$ 2,127	$ 2,599	$ 2,806

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Balance Sheets

Millions of dollars and shares except per share data	December 31 2013	December 31 2012
Assets		
Current assets:		
Cash and equivalents	$ 2,356	$ 2,484
Receivables (less allowance for bad debts of $117 and $92)	6,181	5,787
Inventories	3,305	3,186
Prepaid expenses	737	608
Current deferred income taxes	388	351
Other current assets	737	670
Total current assets	13,704	13,086
Property, plant, and equipment, net of accumulated depreciation of $9,480 and $8,056	11,322	10,257
Goodwill	2,168	2,135
Other assets	2,029	1,932
Total assets	$ 29,223	$ 27,410
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 2,365	$ 2,041
Accrued employee compensation and benefits	1,029	930
Deferred revenue	350	307
Loss contingency for Macondo well incident	278	—
Other current liabilities	1,004	1,474
Total current liabilities	5,026	4,752
Long-term debt	7,816	4,820
Loss contingency for Macondo well incident	1,022	300
Employee compensation and benefits	584	607
Other liabilities	1,160	1,141
Total liabilities	15,608	11,620
Shareholders' equity:		
Common shares, par value $2.50 per share (authorized 2,000 shares, issued 1,072 and 1,073 shares)	2,680	2,682
Paid-in capital in excess of par value	415	486
Accumulated other comprehensive loss	(307)	(309)
Retained earnings	18,842	17,182
Treasury stock, at cost (223 and 144 shares)	(8,049)	(4,276)
Company shareholders' equity	13,581	15,765
Noncontrolling interest in consolidated subsidiaries	34	25
Total shareholders' equity	13,615	15,790
Total liabilities and shareholders' equity	$ 29,223	$ 27,410

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Cash Flows

Millions of dollars	Year Ended December 31 2013	2012	2011
Cash flows from operating activities:			
Net income	$ 2,135	$ 2,645	$ 2,844
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation, depletion, and amortization	1,900	1,628	1,359
Loss contingency for Macondo well incident	1,000	300	—
Provision (benefit) for deferred income taxes, continuing operations	(132)	165	(30)
(Income) loss from discontinued operations, net	(19)	(58)	166
Other changes:			
Receivables	(449)	(682)	(1,218)
Accounts payable	327	200	649
Payment of Barracuda-Caratinga obligation	(219)	—	—
Inventories	(107)	(611)	(564)
Other	11	67	478
Total cash flows from operating activities	4,447	3,654	3,684
Cash flows from investing activities:			
Capital expenditures	(2,934)	(3,566)	(2,953)
Sales of investment securities	356	258	1,001
Purchases of investment securities	(329)	(506)	(501)
Sales of property, plant, and equipment	241	395	160
Acquisitions of business assets, net of cash acquired	(94)	(214)	(880)
Other investing activities	(110)	(55)	(17)
Total cash flows from investing activities	(2,870)	(3,688)	(3,190)
Cash flows from financing activities:			
Payments to reacquire common stock	(4,356)	—	—
Proceeds from long-term borrowings, net of offering costs	2,968	—	978
Dividends to shareholders	(465)	(333)	(330)
Proceeds from exercises of stock options	277	107	160
Other financing activities	(178)	54	25
Total cash flows from financing activities	(1,754)	(172)	833
Effect of exchange rate changes on cash	49	(8)	(27)
Increase (decrease) in cash and equivalents	(128)	(214)	1,300
Cash and equivalents at beginning of year	2,484	2,698	1,398
Cash and equivalents at end of year	$ 2,356	$ 2,484	$ 2,698
Supplemental disclosure of cash flow information:			
Cash payments during the period for:			
Interest	$ 293	$ 294	$ 261
Income taxes	$ 913	$ 1,098	$ 1,285

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Shareholders' Equity

Millions of dollars	Company Shareholders' Equity: Common Shares	Company Shareholders' Equity: Paid-in Capital in Excess of Par Value	Company Shareholders' Equity: Treasury Stock	Company Shareholders' Equity: Retained Earnings	Company Shareholders' Equity: Accumulated Other Comprehensive Income (Loss)	Noncontrolling interest in Consolidated Subsidiaries	Total
Balance at December 31, 2010	$ 2,674	$ 339	$ (4,771)	$ 12,371	$ (240)	$ 14	$ 10,387
Comprehensive income (loss):							
Net income	—	—	—	2,839	—	5	2,844
Other comprehensive loss	—	—	—	—	(33)	(1)	(34)
Cash dividends ($0.36 per share)	—	—	—	(330)	—	—	(330)
Stock plans	9	82	224	—	—	—	315
Other	—	34	—	—	—	—	34
Balance at December 31, 2011	$ 2,683	$ 455	$ (4,547)	$ 14,880	$ (273)	$ 18	$ 13,216
Comprehensive income (loss):							
Net income	—	—	—	2,635	—	10	2,645
Other comprehensive loss	—	—	—	—	(36)	—	(36)
Cash dividends ($0.36 per share)	—	—	—	(333)	—	—	(333)
Stock plans	(1)	25	271	—	—	—	295
Other	—	6	—	—	—	(3)	3
Balance at December 31, 2012	$ 2,682	$ 486	$ (4,276)	$ 17,182	$ (309)	$ 25	$ 15,790
Comprehensive income:							
Net income	—	—	—	2,125	—	10	2,135
Other comprehensive income	—	—	—	—	2	—	2
Common shares repurchased	—	—	(4,356)	—	—	—	(4,356)
Stock plans	(2)	(97)	583	—	—	—	484
Cash dividends ($0.525 per share)	—	—	—	(465)	—	—	(465)
Other	—	26	—	—	—	(1)	25
Balance at December 31, 2013	$ 2,680	$ 415	$ (8,049)	$ 18,842	$ (307)	$ 34	$ 13,615

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, 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 2013, we adopted the provisions of a new accounting standard. See Note 15 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 $588 million in 2013, $460 million in 2012, and $401 million in 2011.

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 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. Changes in the carrying amount of goodwill are detailed below by reportable segment.

Millions of dollars	Completion and Production	Drilling and Evaluation	Total
Balance at December 31, 2011:	$ 1,215	$ 561	$ 1,776
Current year acquisitions	100	62	162
Purchase price adjustments for previous acquisitions	196	1	197
Balance at December 31, 2012:	$ 1,511	$ 624	$ 2,135
Current year acquisitions	43	10	53
Purchase price adjustments for previous acquisitions	(21)	1	(20)
Balance at December 31, 2013:	$ 1,533	$ 635	$ 2,168

The reported amounts of goodwill for each reporting unit are reviewed for impairment on an annual basis, during the third quarter, and more frequently should negative conditions such as significant current or projected operating losses exist. In 2012 and 2011, we elected to perform a qualitative assessment for our annual goodwill impairment test. If a qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, then we would be required to perform a quantitative impairment test for goodwill. In 2013, we elected to bypass the qualitative assessment and perform a quantitative impairment test. This two-step process 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. Our goodwill impairment assessment for 2013 indicated the fair value of each of our reporting units exceeded its carrying amount by a significant margin. Based on our qualitative assessment of goodwill in 2012 and 2011, we concluded that it was more likely than not that the fair value of each of our reporting units was greater than their carrying amount, and therefore no further testing was required. In addition, there were no triggering events that occurred in 2013, 2012, or 2011 requiring us to perform additional impairment reviews. As such, there were no impairments of goodwill recorded in the three-year period ended December 31, 2013.

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 twenty 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 11 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 Production Enhancement, Cementing, Completion Tools, Halliburton Boots & Coots, Multi-Chem, and Halliburton Artificial Lift.

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 provides downhole solutions and services to our customers to complete their wells, including well completion products and services, intelligent well completions, liner hanger systems, sand control systems, and service tools.

Halliburton 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.

Halliburton Artificial Lift offers electrical submersible pumps, including the associated surface package for power, control, and monitoring of the entire lift system, and provides installation, maintenance, repair, and testing services. The objective of these services is to maximize reservoir and wellbore recovery by applying lifting technology and intelligent field management solutions throughout the life of the well.

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

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 logging services that provide information on formation evaluation and reservoir fluid analysis, including formation lithology, rock properties, and reservoir fluid properties. Also offered are cased-hole and slickline services, which provide perforating, pipe recovery services, through-casing formation evaluation and reservoir monitoring, casing and cement integrity measurements, and well intervention services. Borehole seismic services include downhole seismic operations check-shots and vertical seismic profiles, and provide the link between surface seismic and the wellbore. Finally, formation and reservoir solutions transform formation evaluation data into reservoir insight through geoscience solutions.

Testing and Subsea services provide acquisition and analysis of dynamic reservoir information and reservoir optimization solutions to the oil and natural gas industry through a broad portfolio of test tools, data acquisition services, fluid sampling, surface well testing, and subsea safety systems.

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, and related professional and data management services for the upstream oil and natural gas industry.

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 and is primarily composed of cash and equivalents, deferred tax assets, and investment securities. Also included are certain gains, losses and costs not attributable to a particular business segment (such as the loss contingencies related to the Macondo well incident recorded during the first quarters of 2013 and 2012 and the $55 million charitable contribution expensed during the second quarter of 2013).

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	2013	2012	2011
Revenue:			
Completion and Production	$ 17,506	$ 17,380	$ 15,143
Drilling and Evaluation	11,896	11,123	9,686
Total revenue	$ 29,402	$ 28,503	$ 24,829
Operating income:			
Completion and Production	$ 2,875	$ 3,144	$ 3,733
Drilling and Evaluation	1,770	1,675	1,403
Total operations	4,645	4,819	5,136
Corporate and other	(1,507)	(660)	(399)
Total operating income	$ 3,138	$ 4,159	$ 4,737
Interest expense, net of interest income	$ (331)	$ (298)	$ (263)
Other, net	(43)	(39)	(25)
Income from continuing operations before income taxes	$ 2,764	$ 3,822	$ 4,449
Capital expenditures:			
Completion and Production	$ 1,676	$ 2,177	$ 1,669
Drilling and Evaluation	1,210	1,318	1,231
Corporate and other	48	71	53
Total	$ 2,934	$ 3,566	$ 2,953
Depreciation, depletion, and amortization:			
Completion and Production	$ 1,013	$ 843	$ 680
Drilling and Evaluation	873	783	676
Corporate and other	14	2	3
Total	$ 1,900	$ 1,628	$ 1,359

	December 31	
Millions of dollars	2013	2012
Total assets:		
Completion and Production	$ 14,203	$ 13,313
Drilling and Evaluation	10,010	9,290
Shared assets	1,351	1,376
Corporate and other	3,659	3,431
Total	$ 29,223	$ 27,410

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 and equivalents, 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

	Year Ended December 31		
Millions of dollars	2013	2012	2011
Revenue:			
United States	$ 14,311	$ 15,057	$ 13,548
Other countries	15,091	13,446	11,281
Total	$ 29,402	$ 28,503	$ 24,829

	December 31	
Millions of dollars	2013	2012
Net property, plant, and equipment:		
United States	$ 5,368	$ 5,096
Other countries	5,954	5,161
Total	$ 11,322	$ 10,257

Note 3. Receivables

Our trade receivables are generally not collateralized. At December 31, 2013 and December 31, 2012, 34% and 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.

We continue to experience delays in collecting payment on our receivables from our primary customer in Venezuela. These receivables are not disputed, and we have not historically had material write-offs relating to this customer. Our total outstanding trade receivables in Venezuela were $486 million, or approximately 8% of our gross trade receivables, as of December 31, 2013, compared to $491 million, or approximately 9% of our gross trade receivables, as of December 31, 2012. Of the $486 million receivables in Venezuela as of December 31, 2013, $183 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets. Of the $491 million receivables in Venezuela as of December 31, 2012, $143 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets.

The following table presents a rollforward of our allowance for bad debts for 2011, 2012, and 2013.

Millions of dollars	Balance at Beginning of Period	Charged to Costs and Expenses	Write-Offs	Balance at End of Period
Year ended December 31, 2011	$ 91	$ 53	$ (7)	$ 137
Year ended December 31, 2012	137	(40)	(5)	92
Year ended December 31, 2013	92	39	(14)	117

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 and totaled $157 million at December 31, 2013 and $139 million at December 31, 2012. If the average cost method had been used, total inventories would have been $35 million higher than reported at December 31, 2013 and $41 million higher than reported at December 31, 2012. The cost of the remaining inventory was recorded on the average cost method. Inventories consisted of the following:

	December 31	
Millions of dollars	2013	2012
Finished products and parts	$ 2,445	$ 2,264
Raw materials and supplies	720	793
Work in process	140	129
Total	$ 3,305	$ 3,186

Finished products and parts are reported net of obsolescence reserves of $130 million at December 31, 2013 and $114 million at December 31, 2012.

Note 5. Property, Plant, and Equipment

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

Millions of dollars	December 31 2013	December 31 2012
Land	$ 213	$ 145
Buildings and property improvements	2,685	1,861
Machinery, equipment, and other	17,904	16,307
Total	20,802	18,313
Less accumulated depreciation	9,480	8,056
Net property, plant, and equipment	$ 11,322	$ 10,257

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

	Buildings and Property Improvements 2013	Buildings and Property Improvements 2012
1 - 10 years	13%	14%
11 - 20 years	43%	46%
21 - 30 years	20%	14%
31 - 40 years	24%	26%

	Machinery, Equipment, and Other 2013	Machinery, Equipment, and Other 2012
1 - 5 years	22%	20%
6 - 10 years	72%	74%
11 - 20 years	6%	6%

Note 6. Debt

Long-term debt consisted of the following:

Millions of dollars	December 31 2013	December 31 2012
3.5% senior notes due August 2023	$ 1,098	$ —
6.15% senior notes due September 2019	997	997
7.45% senior notes due September 2039	995	995
4.75% senior notes due August 2043	898	—
6.7% senior notes due September 2038	800	800
1.0% senior notes due August 2016	600	—
3.25% senior notes due November 2021	498	498
4.5% senior notes due November 2041	498	498
2.0% senior notes due August 2018	400	—
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	$ 7,816	$ 4,820

Senior debt

All of our senior notes and debentures rank equally with our existing and future senior unsecured indebtedness, have semiannual interest payments, and have 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

We have an unsecured $3.0 billion revolving credit facility expiring in 2018. 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, 2013.

Debt maturities

Our long-term debt matures as follows: $600 million in 2016, $45 million in 2017, $800 million in 2018, and the remainder in 2019 and thereafter.

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. We entered into various agreements relating to the separation of KBR, including, among others, a Master Separation Agreement (MSA) and a Tax Sharing Agreement (TSA). We recorded a liability at that time reflecting the estimated fair value of the indemnities provided to KBR. 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.” Amounts accrued relating to our KBR indemnity obligations were included in “Other liabilities” in our consolidated balance sheets and totaled $219 million as of December 31, 2012. In 2013, we paid $219 million to satisfy our obligation under a guarantee related to the Barracuda-Caratinga matter, a legacy KBR project. Accordingly, there were no amounts accrued for indemnities provided to KBR at December 31, 2013.

Tax sharing agreement

The TSA provides for the calculation and allocation of United States and certain other jurisdiction tax liabilities between KBR and us for the periods 2001 through the date of separation. The TSA is complex, and finalization of amounts owed between KBR and us under the TSA can occur only after income tax audits are completed by the taxing authorities and both parties have had time to analyze the results.

During the second quarter of 2012, we sent a notice under the TSA to KBR requesting the appointment of an arbitrator in accordance with the terms of the TSA. This request asked the arbitrator to find that KBR owed us a certain amount pursuant to the TSA. KBR denied that it owed us any amount and asserted instead that we owed KBR a certain amount under the TSA. KBR also asserted that it believes the MSA controls its defenses to our TSA claim and demanded arbitration of those defenses under the MSA. In July 2012, we filed suit in the District Court of Harris County, Texas, seeking to compel KBR to arbitrate the entire dispute in accordance with the provisions of the TSA, rather than the MSA. KBR filed a cross-motion seeking to compel arbitration of its defenses under the MSA. In September 2012, the court denied our motion and granted KBR's motion to compel arbitration under the MSA. We continue to believe that the TSA was intended to govern the entire matter and have appealed. The appeal is pending.

In May 2013, KBR's defenses were arbitrated before a panel appointed pursuant to the MSA. In June 2013, the panel issued its decision, finding it had jurisdiction to hear the dispute and that a portion of our claims made under the TSA were barred by the time limitation provision in the MSA. In September 2013, we filed a motion and an application to vacate the panel's decision with the District Court of Harris County, Texas. The court has not ruled on the motion or application.

The MSA panel also ordered the parties to return to the TSA arbitrator for determination of the parties' remaining claims under the TSA. On October 9, 2013, the TSA arbitrator issued a report regarding the claims made by each party. The report found that KBR owes us a net amount of approximately $105 million, plus interest, with each party bearing its own costs related to the matter.

On October 21, 2013, KBR submitted a request for clarification and reconsideration of the TSA arbitrator's report. In December 2013, the TSA arbitrator issued a supplemental report that reaffirmed the award.

In January 2014, KBR filed a motion with the MSA panel to enforce the panel's June 2013 decision. KBR's motion claimed, among other things, that certain of our claims submitted to the TSA arbitrator were time-barred under the MSA and that the TSA arbitrator misinterpreted the TSA. On February 3, 2014, we filed a response to KBR's motion and an application to confirm the TSA arbitrator's award with the District Court of Harris County, Texas. Due to the uncertainty surrounding the ultimate determination of the parties' claims under the TSA, no material anticipated recovery amounts or liabilities related to this matter have been recognized in the consolidated financial statements as of December 31, 2013.

Note 8. Commitments and Contingencies

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. 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). There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

We are currently unable to fully estimate the impact the Macondo well incident will have on us. The multi-district litigation (MDL) proceeding referred to below is ongoing. We cannot predict the outcome of the many lawsuits and investigations relating to the Macondo well incident, including orders and rulings of the court that impact the MDL, the results of the MDL trial, the effect that the settlements between BP and the Plaintiffs' Steering Committee (PSC) in the MDL and other settlements may have on claims against us, or whether we might settle with one or more of the parties to any lawsuit or investigation. The first two phases of the MDL trial have concluded, and the MDL court could begin issuing rulings at any time. A determination that the performance of our services on the Deepwater Horizon constituted gross negligence could result in substantial liability to the numerous plaintiffs for punitive damages and potentially to BP with respect to its direct claims against us.

As of December 31, 2013, our loss contingency reserve for the Macondo well incident, relating to the MDL, remained at $1.3 billion, consisting of a current portion of $278 million and a non-current portion of $1.0 billion. This reserve represents a loss contingency that is probable and for which a reasonable estimate of a loss can be made, although we continue to believe that we have substantial legal arguments and defenses against any liability and that BP's indemnity obligation protects us as described below. This loss contingency reserve does not include potential recoveries from our insurers.

We have participated in intermittent discussions with the PSC regarding the potential for a settlement that would resolve a substantial portion of the claims pending in the MDL trial. BP, however, has not participated in any recent settlement discussions with us. Reaching a settlement involves a complex process, and there can be no assurance as to whether or when we may complete a settlement. In addition, the settlement discussions we have had to date do not cover all parties and claims relating to the Macondo well incident. Accordingly, there are additional loss contingencies relating to the Macondo well incident that are reasonably possible but for which we cannot make a reasonable estimate. Given the numerous potential developments relating to the MDL and other lawsuits and investigations, which could occur at any time, we may adjust our estimated loss contingency reserve in the future. Liabilities arising out of the Macondo well incident could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Investigations and Regulatory Action. Several regulatory agencies and others, including the specially constituted National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), conducted investigations of the Macondo well incident, and reports issued as a result of those investigations have been critical of BP, Transocean, and us, among others. For example, one or more of those reports have concluded that primary cement failure was a direct cause of the blowout, that cement testing performed by an independent laboratory “strongly suggests” that the foam cement slurry used on the Macondo well was unstable, and that numerous other oversights and factors caused or contributed to the cause of the incident, including BP's failure to run a cement bond log, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, natural gas, or fluid into the well was occurring, communication failures among BP, Transocean, and us, and flawed decisions relating to the design, construction, and testing of barriers critical to the temporary abandonment of the well. The U.S. Chemical Safety and Hazard Investigation Board is also conducting an investigation of the incident.

In October 2011, the Bureau of Safety and Environmental Enforcement (BSEE) issued a notification of Incidents of Noncompliance (INCs) to us for allegedly violating federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the Macondo well under control, the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico, and 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 the Interior Board of Land Appeals (IBLA). In January 2012, the IBLA, in response to our and the BSEE's joint request, suspended the appeal pending certain proceedings in the MDL trial. Once the MDL court issues a final decision in the trial, we expect to file a proposal for further action in the appeal within

60 days. 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.

The Cementing Job and Reaction to Reports. We disagree with the reports referred to above regarding many of their findings and characterizations with respect to our 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 other investigatory bodies that we believe has been overlooked or omitted from their reports, 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. Also, we believe that BP knew or should have known about a critical, additional hydrocarbon zone in the well that BP failed to disclose to us prior to the design of the cement program for the Macondo well.

At this time we cannot predict the impact of the investigations or reports referred to above, or the conclusions or impact of future investigations or reports. We also cannot predict whether any investigations or reports 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. We intend to continue to cooperate fully with all 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.

DOJ Investigations and Actions. On June 1, 2010, the United States Attorney General announced that the United States 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), and the Endangered Species Act of 1973 (ESA).

The CWA provides authority for civil 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. 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 ESA establishes liability for injury and death to wildlife. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation.

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), which 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 equitable contribution with respect to liabilities incurred by BP Exploration under the OPA or another law, which subsequent court filings have indicated may include the CWA, and requested a judgment that the DOJ assert its claims for OPA financial liability directly against us. We filed a motion to dismiss BP Exploration's claim, and that motion is pending. In July 2013, we also filed a motion for summary judgment requesting a court order that we are not liable to BP or Transocean for equitable indemnification or contribution with regard to any CWA fines and penalties that have been assessed or may be assessed against BP or Transocean. That motion is also pending.

We were not 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 were not included in the DOJ's civil complaint, there can be no assurance that federal governmental authorities will not bring a civil action against us under the CWA, the OPA, and/or other statutes or regulations.

In July 2013, we reached an agreement with the DOJ to conclude the federal government's criminal investigation of us in relation to the Macondo well incident. Pursuant to a cooperation guilty plea agreement, Halliburton Energy Services, Inc., our wholly owned subsidiary (HESI), agreed to plead guilty to one misdemeanor violation of federal law concerning the deletion of certain computer files created after the occurrence of the Macondo well incident. Pursuant to the plea agreement, HESI agreed to pay a criminal fine of $0.2 million within five days of sentencing and agreed to three years' probation. The DOJ has agreed that it will not pursue further criminal prosecution of us (including our subsidiaries) for any conduct relating to or arising out of the Macondo well incident. We have agreed to continue to cooperate with the DOJ in any ongoing investigation related to or arising from the incident. In September 2013, our guilty plea was entered and approved by a federal district court judge on the terms and conditions of the plea agreement, and the DOJ closed its criminal investigation of us in relation to the Macondo well incident.

In November 2012, BP announced that it reached an agreement with the DOJ to resolve all federal criminal charges against it stemming from the Macondo well incident. BP agreed to plead guilty to 14 criminal charges, with 13 of those charges based on the negligent misinterpretation of the negative-pressure test conducted on the Deepwater Horizon. BP also agreed to pay $4.0 billion, including approximately $1.3 billion in criminal fines, to take actions to further enhance the safety of drilling operations in the Gulf of Mexico, to a term of five years' probation, and to the appointment of two monitors with four-year terms, one relating to process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico and one relating to the improvement, implementation, and enforcement of BP's code of conduct.

In January 2013, Transocean announced that it reached an agreement with the DOJ to resolve certain claims for civil penalties and potential criminal claims against it arising from the Macondo well incident. Transocean agreed to plead guilty to one misdemeanor violation of the CWA for negligent discharge of oil into the Gulf of Mexico, to pay $1.0 billion in CWA penalties and $400 million in fines and recoveries, to implement certain measures to prevent a recurrence of an uncontrolled discharge of hydrocarbons, and to a term of five years' probation.

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 1,800 complaints, most of which are alleged class actions, involving pollution damage claims and at least eight personal injury lawsuits involving four decedents and at least 10 allegedly injured persons who were on the drilling rig at the time of the incident. At least six additional lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill.

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 Migratory Bird Treaty Act of 1918, 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 all of the coastal states of the Gulf of Mexico, numerous local governmental entities, the Mexican State of Yucatan, and the United Mexican States.

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.

Plaintiffs originally filed the lawsuits described above in federal and state courts throughout the United States. Except for a relatively small number of lawsuits not yet consolidated, 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.

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. While the Limitation Action has been formally consolidated into the MDL, the court is nonetheless, in some respects, treating the Limitation Action as an associated but separate proceeding. In February 2011, Transocean tendered us, along with all other defendants, into the Limitation Action. As a result of the tender, we and all other defendants are being treated as direct defendants to the plaintiffs' claims as if the plaintiffs had sued 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 intends to determine the liability, limitation, exoneration, and fault allocation with regard to all of the defendants in a trial, which to date has occurred in two phases. We do not believe that a single determination 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.

The defendants in the proceedings described above have filed numerous cross claims and third party claims against certain other defendants. Claims against us seek subrogation, contribution, indemnification, including with respect to liabilities under the OPA, and direct damages, and allege negligence, gross negligence, fraudulent conduct, willful misconduct, fraudulent concealment, comparative fault, and breach of warranty of workmanlike performance. Additional civil lawsuits may be filed against us. In addition to the claims against us, generally the defendants in the proceedings described above, including us, filed claims, including for liabilities under the OPA and other claims similar to those described above, against the other defendants. Our claims against the other defendants seek contribution and indemnification, and allege negligence, gross negligence and willful misconduct. Several of the parties have settled claims among themselves, and claims against some parties have been dismissed. We have also filed an 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 all claims brought under state law causes of action were dismissed; (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 responsible and non-responsible parties under general maritime law. 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. The rulings in the court's order remain subject to each applicable party's right to appeal. Certain parishes in Louisiana are currently appealing the dismissal of their state law claims under the order.

In April 2012, BP announced that it had reached definitive settlement agreements with the PSC to resolve the substantial majority of eligible private economic loss and medical claims stemming from the Macondo well incident. The PSC acts on behalf of individuals and business plaintiffs in the MDL. According to BP, the settlements do not include claims against BP made by the DOJ or other federal agencies or by states and local governments. In addition, the settlements provide that, to the extent permitted by law, BP will assign to the settlement class certain of its claims, rights, and recoveries against Transocean and us for damages, including BP's alleged direct damages such as damages for clean-up expenses and damage to the well and reservoir. We do not believe that our contract with BP Exploration permits the assignment of certain claims to the settlement class without our consent. The MDL court has since confirmed certification of the classes for both settlements and granted final approval of the settlements. We objected to the settlements on the grounds set forth above, among other reasons. The MDL court held, however, that we, as a non-settling defendant, lacked standing to object to the settlements but noted that it did not express any opinion as to the validity of BP's assignment of certain claims to the settlement class and that the settlements do not affect any of our procedural or substantive rights in the MDL. BP has been challenging certain provisions of its settlement of economic loss claims in the MDL court and before the United States Fifth Circuit Court of Appeals. We are unable to predict at this time the effect that the settlements, or any challenge, modification, or overturning of the settlements, may have on claims against us.

The MDL court has dismissed: (1) claims by or on behalf of owners, lessors, and lessees of real property that allege to have suffered a reduction in the value of real property even though the property was not physically touched by oil and the property was not sold; (2) claims for economic losses based solely on consumers' decisions not to purchase fuel or goods from BP fuel stations and stores based on consumer animosity toward BP; and (3) claims by or on behalf of recreational fishermen, divers, beachgoers, boaters and others that allege damages such as loss of enjoyment of life from their inability to use portions of the Gulf of Mexico for recreational and amusement purposes. In dismissing those claims, the MDL court also noted that we are not liable with respect to those claims under the OPA because we are not a "responsible party" under OPA. A group of plaintiffs appealed the order, but the Fifth Circuit dismissed the appeal.

The first phase of the MDL trial, which concluded in April 2013, covered issues arising out of the conduct and degree of culpability of various parties allegedly relevant to the loss of well control, the ensuing fire and explosion on and sinking of the Deepwater Horizon, and the initiation of the release of hydrocarbons from the Macondo well. At the conclusion of the plaintiffs' case, we and the other defendants each submitted a motion requesting the MDL court to dismiss certain claims. In March 2013, the MDL court denied our motion and declined to dismiss any claims, including those alleging gross negligence, against BP, Transocean and us. In addition, the MDL court dismissed all claims against M-I Swaco and claims alleging gross negligence against Cameron International Corporation (Cameron). In April 2013, the MDL court dismissed all remaining claims against Cameron, leaving BP, Transocean, and us as the remaining defendants with respect to the matters addressed during the first phase of the trial.

Also in March 2013, we advised the MDL court that we recently found a rig sample of dry cement blend collected at another well that was cemented before the Macondo well using the same dry cement blend as used on the Macondo production casing. In April 2013, we advised the MDL parties that we recently discovered some additional documents related to the Macondo well incident. BP and others have asked the court to impose sanctions and adverse findings against us because, according to their allegations, we should have identified the cement sample in 2010 and the additional documents by October 2011. BP also reasserted its previous allegations that we destroyed evidence relating to post-incident testing of the foam cement slurry on the Deepwater Horizon. The MDL court has not ruled on the requests for sanctions and adverse findings. We believe that the discoveries were the result of simple misunderstandings or mistakes and do not involve any material evidence, and that sanctions are not warranted.

When our plea agreement with the DOJ was announced in July 2013, BP filed a motion requesting that the MDL court re-open the evidence for phase one of the MDL trial to take into account our guilty plea and re-urging their request for sanctions. After the plea was entered, the PSC and the States of Alabama and Louisiana (as coordinating counsel for the states involved in the MDL) filed a motion likewise seeking to admit the guilty plea agreement and other court filings into evidence and asking that the MDL court use that evidence as a basis for assessing punitive damages against us. We filed replies opposing both motions and setting forth our position that the deleted post-incident computer simulations were not evidence, were not relevant, and in any event were re-created. The MDL court has not ruled on the motions.

The second phase of the MDL trial was split into two parts, with testimony presented in October 2013. The first part covered attempts to collect, control, or halt the flow of hydrocarbons from the well, while the second part covered the quantification of hydrocarbons discharged from the well. The parties submitted proposed findings of fact and conclusions of law, post-trial briefs and responses during December 2013 and January 2014. According to a stipulation and post-trial filings, BP contends that 2.45 million barrels of oil were released into the Gulf of Mexico and the DOJ contends that a total of 4.2 million barrels were released. The MDL court has not issued a ruling on the questions that were the subject of the first two phases of the trial, although those rulings could be issued at any time.

Subsequent proceedings would be held to the extent triable issues remain unresolved by the first two phases of the trial, settlements, motion practice, or stipulation. Although the DOJ participated in the first two phases of the trial with regard to BP's conduct and the amount of hydrocarbons discharged from the well, the MDL court anticipates that the DOJ's civil action for the CWA violations, fines, and penalties will be addressed by the court in a third phase of the trial to the extent necessary.

Damages for the cases tried in the MDL proceeding, including punitive damages, are expected to be tried following the issuance of the MDL court's rulings regarding the phases 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. The judge has indicated that he intends for the State of Alabama's OPA compensatory damages claims against BP be tried as a test case.

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.

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, but BP has filed a claim for equitable contribution against us with respect to its liabilities. 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.

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 proceeding. 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.

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 December 31, 2013, we have incurred legal fees and related expenses of approximately $264 million, of which $235 million has been reimbursed under or is expected to be covered by our insurance program. 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.

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.

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 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. We filed a Petition for Leave to Appeal with the Fifth Circuit, which was granted. In April 2013, the Fifth Circuit issued an order affirming the District Court's order certifying the class.

We filed a writ of certiorari with the United States Supreme Court seeking an appeal of the Fifth Circuit decision. In November 2013, the Supreme Court granted our writ. Oral argument is scheduled to be held before the Supreme Court on March 5, 2014. Fact discovery in this case has resumed. We cannot predict the outcome or consequences of this case, which we intend to vigorously defend.

Investigations

We are conducting internal investigations of certain areas of our operations in Angola and Iraq, 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.

During the second quarter of 2012, in connection with a meeting with the DOJ and the SEC regarding the above investigation, we advised the DOJ and the SEC that we were initiating unrelated, internal investigations into payments made to a third-party agent relating to certain customs matters in Angola and to third-party agents relating to certain customs and visa matters in Iraq.

Since the initiation of the investigations described above, we have participated in meetings with the DOJ and the SEC to brief them on the status of the investigations and have been producing documents to them both voluntarily and as a result of SEC subpoenas to us and certain of our current and former officers and employees.

We expect to continue to have discussions with the DOJ and the SEC regarding the Angola and Iraq matters described above and have indicated that we would further update them as our investigations progress. We have engaged outside counsel and independent forensic accountants to assist us with these investigations.

During the second quarter of 2013, we received a civil investigative demand from the Antitrust Division of the DOJ regarding pressure pumping services. We have engaged in discussions with the DOJ on this matter and have provided responses to the DOJ's information requests. We understand there have been others in our industry who have received similar correspondence from the DOJ, and we do not believe that we are being singled out for any particular scrutiny.

We intend to continue to cooperate with the DOJ's and the SEC's inquiries and requests in these investigations. Because these investigations are ongoing, 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.

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, 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 claims and remediation requirements to have a material adverse effect on our liquidity, consolidated results of operations, or consolidated financial position. Excluding our loss contingency for the Macondo well incident, our accrued liabilities for environmental matters were $66 million as of December 31, 2013 and $72 million as of December 31, 2012. Because 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. Our total liability related to environmental matters covers numerous properties.

In November 2012, we received an Enforcement Notice from the Pennsylvania Department of Environmental Protection (PADEP) regarding an alleged improper disposal of oil field acid in or around Homer City, Pennsylvania between 1999 and 2011. In February 2014, we agreed to resolve this matter for $2 million to settle the PADEP's claim for civil penalties.

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, 2013, those nine sites accounted for approximately $5 million of our $66 million total environmental reserve. 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 $2.1 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2013, including $192 million of surety bond guarantees related to our Venezuelan operations. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Leases

We are party to numerous operating leases, principally for the use of land, offices, equipment, manufacturing and field facilities, and warehouses. Total rentals on our operating leases, net of sublease rentals, were $958 million in 2013, $850 million in 2012, and $735 million in 2011.

Future total rentals on our noncancellable operating leases are $946 million in the aggregate, which includes the following: $282 million in 2014; $215 million in 2015; $156 million in 2016; $83 million in 2017; $56 million in 2018; and $154 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	2013	2012	2011
Current income taxes:			
Federal	$ (245)	$ (695)	$ (1,026)
Foreign	(485)	(328)	(334)
State	(49)	(47)	(109)
Total current	(779)	(1,070)	(1,469)
Deferred income taxes:			
Federal	4	(168)	(28)
Foreign	125	15	57
State	2	(12)	1
Total deferred	131	(165)	30
Provision for income taxes	$ (648)	$ (1,235)	$ (1,439)

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

	Year Ended December 31		
Millions of dollars	2013	2012	2011
United States	$ 1,070	$ 2,826	$ 4,040
Foreign	1,694	996	409
Total	$ 2,764	$ 3,822	$ 4,449

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		
	2013	2012	2011
United States statutory rate	35.0%	35.0%	35.0%
Impact of foreign income taxed at different rates	(9.3)	(2.5)	(0.5)
Domestic manufacturing deduction	(2.0)	(2.2)	(2.1)
State income taxes	1.7	1.6	1.6
Adjustments of prior year taxes	(1.3)	(0.6)	(1.5)
Other impact of foreign operations	(0.2)	(0.5)	(0.4)
Other items, net	(0.4)	1.5	0.2
Total effective tax rate on continuing operations	23.5%	32.3%	32.3%

Our effective tax rate on continuing operations was 23.5% for 2013 and 32.3% for 2012 and 2011. The 2013 effective tax rate on continuing operations was positively impacted by several items during the year, including federal tax benefits of approximately $50 million due to the reinstatement of certain tax benefits and credits related to the first quarter enactment of the American Taxpayer Relief Act of 2012. Also contributing to the lower tax rate in 2013 was a $1.0 billion loss contingency related to the Macondo well incident, which was tax-effected at the United States statutory rate, as well as some favorable tax items in Latin America in the fourth quarter. Additionally, our effective tax rate was positively impacted by lower tax rates in certain foreign jurisdictions, as we continue to reposition our technology, supply chain, and manufacturing infrastructure to more effectively serve our customers internationally.

We have not provided United States income taxes and foreign withholding taxes on the undistributed earnings of foreign subsidiaries as of December 31, 2013 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, 2013, the cumulative amount of earnings upon which United States income taxes have not been provided is approximately $6.1 billion. It is not practicable 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	2013	2012
Gross deferred tax assets:		
Net operating loss carryforwards	$ 481	$ 474
Accrued liabilities	600	329
Employee compensation and benefits	351	375
Other	162	160
Total gross deferred tax assets	1,594	1,338
Gross deferred tax liabilities:		
Depreciation and amortization	1,185	859
Other	81	137
Total gross deferred tax liabilities	1,266	996
Valuation allowances – net operating loss carryforwards	374	395
Net deferred income tax asset (liability)	$ (46)	$ (53)

At December 31, 2013, we had $1.6 billion of net operating loss carryforwards, of which $161 million will expire from 2014 through 2017, $295 million will expire from 2018 through 2022, and $53 million will expire from 2023 through 2033. The remaining balance will not expire.

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, 2011	$ 177	$ 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	$ 69
Change in prior year tax positions	16	(1)
Change in current year tax positions	14	1
Cash settlements with taxing authorities	(3)	—
Lapse of statute of limitations	(4)	(1)
Balance at December 31, 2012	$ 228 (a)	$ 68
Change in prior year tax positions	(53)	(9)
Change in current year tax positions	30	1
Cash settlements with taxing authorities	(21)	(17)
Lapse of statute of limitations	(9)	(9)
Balance at December 31, 2013	$ 175 (a)(b)	$ 34

(a) Includes $27 million as of December 31, 2013 and $59 million as of December 31, 2012 in foreign unrecognized tax benefits that would give rise to a United States tax credit. The remaining balance of $138 million, which excludes $10 million of unrecognized tax benefits covered by an indemnification asset, as of December 31, 2013 and $169 million as of December 31, 2012, 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 $3 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 2005. 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 for the tax year 2012 is open for review, 2003 through 2009 are under appeal for tax items not agreed, and 2010 through 2011 are under examination by the Internal Revenue Service. During 2013, the Congressional Joint Committee on Taxation approved a $135 million income tax refund, excluding interest, to us for tax items agreed upon for the tax years 2003 through 2009.

Note 10. Shareholders' Equity

Shares of common stock

The following table summarizes total shares of common stock outstanding:

	December 31	
Millions of shares	2013	2012
Issued	1,072	1,073
In treasury	(223)	(144)
Total shares of common stock outstanding	849	929

In July 2013, our Board of Directors increased the authorization to purchase Halliburton common stock under our stock repurchase program by $4.3 billion, to a new total repurchase capacity of $5.0 billion. In August 2013, we repurchased approximately 68 million shares of our common stock for an aggregate cost of $3.3 billion at a purchase price of $48.50 per share, excluding fees and expenses, pursuant to a modified Dutch auction cash tender offer. Including the shares purchased pursuant to the tender offer, during the year ended December 31, 2013, we repurchased approximately 93 million shares of our common stock for a total cost of approximately $4.4 billion at an average price of $47.02 per share.

As of December 31, 2013, approximately $1.7 billion of purchase authorization remained available under the stock repurchase program. 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, 2013, we repurchased approximately 188 million shares of our common stock for approximately $7.6 billion at an average price per share of $40.52.

Preferred stock

Our preferred stock consists of five million total authorized shares at December 31, 2013, of which none are issued.

Accumulated other comprehensive loss

Accumulated other comprehensive loss consisted of the following:

	December 31	
Millions of dollars	2013	2012
Defined benefit and other postretirement liability adjustments (a)	$ (241)	$ (241)
Cumulative translation adjustment	(69)	(69)
Other	3	1
Total accumulated other comprehensive loss	$ (307)	$ (309)

(a) Included net actuarial losses for our international pension plans of $222 million at December 31, 2013 and $208 million at December 31, 2012.

Amounts reclassified out of accumulated other comprehensive loss and the tax effects allocated to each component of other comprehensive income were not material for the year ended December 31, 2013 or 2012.

Note 11. Stock-based Compensation

The following table summarizes stock-based compensation costs for the years ended December 31, 2013, 2012, and 2011.

	Year Ended December 31		
Millions of dollars	2013	2012	2011
Stock-based compensation cost	$ 264	$ 217	$ 198
Tax benefit	(81)	(67)	(61)
Stock-based compensation cost, net of tax	$ 183	$ 150	$ 137

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, stock value equivalent awards, or incentive stock options outstanding.

Under the terms of the Stock Plan, approximately 172 million shares of common stock have been reserved for issuance to employees and non-employee directors. At December 31, 2013, approximately 28 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 2013.

	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, 2013	18.1	$ 32.23		
Granted	5.4	43.06		
Exercised	(4.7)	27.35		
Forfeited/expired	(0.7)	37.37		
Outstanding at December 31, 2013	18.1	$ 36.57	7.1	$ 256
Exercisable at December 31, 2013	9.0	$ 33.48	5.3	$ 156

The total intrinsic value of options exercised was $93 million in 2013, $12 million in 2012, and $102 million in 2011. As of December 31, 2013, there was $83 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 two years.

Cash received from option exercises was $277 million during 2013, $107 million during 2012, and $160 million during 2011.

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		
	2013	2012	2011
Expected term (in years)	5.27	5.21	5.20
Expected volatility	40%	46%	40%
Expected dividend yield	0.94 - 1.33%	0.99 – 1.24%	0.69 – 1.01%
Risk-free interest rate	0.77 - 1.73%	0.65 – 1.15%	0.93 – 2.29%
Weighted average grant-date fair value per share	$14.34	$11.99	$15.61

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 or, beginning in 2012, an annual award of 800 restricted stock units representing the right to receive shares of common stock as a part of their compensation. These awards have a minimum restriction period of six months, and, with respect to the restricted share awards, the restrictions lapse upon the earlier of mandatory director retirement at age 72 or early retirement from the Board after four years of service. With respect to the restricted stock unit awards, the restrictions lapse 25% annually over four years of service. If the non-employee director has made a timely election to defer receipt of the shares upon vesting, then the shares are distributed at the end of January in the year following the year of the non-employee director's mandatory retirement at age 72 or early retirement from the Board after four years of service in a single distribution or in annual installments over a 5- or 10-year period as elected by the director.

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, 2013, 39,200 restricted shares and 13,506 restricted stock units were issued and outstanding under the Directors Plan. In addition, during 2013, our non-employee directors were awarded 29,797 restricted stock units under the Stock Plan with the same terms and conditions as those described above for the Directors Plan.

The following table represents our Stock Plan and Directors Plan restricted stock awards and restricted stock units granted, vested, and forfeited during 2013.

	Number of Shares (in millions)	Weighted Average Grant-Date Fair Value per Share
Nonvested shares at January 1, 2013	14.8	$ 33.17
Granted	6.6	42.93
Vested	(4.7)	32.14
Forfeited	(1.0)	35.65
Nonvested shares at December 31, 2013	15.7	$ 37.43

The weighted average grant-date fair value of shares granted during 2012 was $32.17 and during 2011 was $43.35. The total fair value of shares vested during 2013 was $208 million, during 2012 was $126 million, and during 2011 was $165 million. As of December 31, 2013, there was $420 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 four 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. For the years ended December 31, 2012 and 2011, the ESPP contained two six-month offering periods commencing on January 1 and July 1. Beginning in 2013, the ESPP contained four three-month offering periods commencing on January 1, April 1, July 1, and October 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. The stock to be offered may be authorized but unissued common shares or treasury shares. As of December 31, 2013, 33 million shares have been sold through the ESPP and 11 million shares are available for future issuance.

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:

	Year Ended December 31		
	2013	2012	2011
Expected volatility	27%	49%	38%
Expected dividend yield	1.12%	1.16%	0.78%
Risk-free interest rate	0.06%	0.11%	0.14%
Weighted average grant-date fair value per share	$ 8.40	$ 8.93	$ 11.88

Note 12. 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. Differences between basic and diluted weighted average common shares outstanding for all periods presented resulted from the dilutive effect of awards granted under our stock incentive plans.

Excluded from the computation of diluted income per share are options to purchase three million shares of common stock that were outstanding in 2013, seven million shares of common stock that were outstanding in 2012, and three million shares of common stock that were outstanding in 2011. 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 13. Financial Instruments and Risk Management

At December 31, 2013, we held $373 million of investments in fixed income securities with maturities that extend through November 2016 compared to $398 million of investments in fixed income securities held at December 31, 2012. These securities are accounted for as available-for-sale and recorded at fair value as follows:

	December 31, 2013			December 31, 2012		
Millions of dollars	Level 1	Level 2	Total	Level 1	Level 2	Total
Fixed Income Securities:						
U.S. treasuries (a)	$ 100	$ —	$ 100	$ 150	$ —	$ 150
Other (b)	—	273	273	—	248	248
Total	$ 100	$ 273	$ 373	$ 150	$ 248	$ 398

(a) These securities are classified as "Other current assets" in our consolidated balance sheets.

(b) Of these securities, $139 million are classified as “Other current assets” and $134 million are classified as “Other assets” on our consolidated balance sheets as of December 31, 2013, compared to $120 million classified as "Other current assets" and $128 million classified as "Other assets" as of December 31, 2012. These securities consist primarily of municipal bonds, corporate bonds, and other debt instruments.

Our Level 1 asset fair values are based on quoted prices in active markets and our Level 2 asset fair values are based on quoted prices for identical assets in less active markets. We have no financial instruments measured at fair value using unobservable inputs (Level 3). The carrying amount of cash and equivalents, receivables, and accounts payable, as reflected in the consolidated balance sheets, approximates fair value due to the short maturities of these instruments.

The carrying amount and fair value of our long-term debt is as follows:

	December 31, 2013				December 31, 2012			
Millions of dollars	Level 1	Level 2	Total fair value	Carrying value	Level 1	Level 2	Total fair value	Carrying value
Long-term debt	$ 8,405	$ 292	$ 8,697	$ 7,816	$ 1,112	$ 5,272	$ 6,384	$ 4,820

Our Level 1 debt fair values are calculated using quoted prices in active markets for identical liabilities with transactions occurring on the last two days of year-end. Our Level 2 debt fair values are calculated using significant observable inputs for similar liabilities where estimated values are determined from observable data points on our other bonds and on other similarly rated corporate debt or from observable data points of transactions occurring prior to two days from year-end and adjusting for changes in market conditions. We have no debt measured at fair value using unobservable inputs (Level 3).

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 foreign exchange contracts, foreign exchange options, 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 contracts, options, and interest rate swaps was not material as of December 31, 2013 or December 31, 2012. The counterparties to our derivatives 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 exchange instruments, some of which are designed to mitigate the impact of foreign currency risks related to the Venezuelan bolívar. 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 contracts and options to manage our exposure to fluctuations in the currencies of the countries in which we do the majority of our international business. These instruments are not treated as hedges for accounting purposes, generally have an expiration date of one year or less, and are not exchange traded. While these instruments 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 instruments may limit our ability to benefit from favorable fluctuations in foreign currency exchange rates.

Derivatives 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 foreign exchange derivatives were $769 million at December 31, 2013 and $324 million at December 31, 2012. The notional amounts of these instruments 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 and some of our long-term investments in fixed income securities. Our short-term borrowings and short-term investments in fixed income securities do not give rise to significant interest rate risk due to their short-term nature. We had fixed rate long-term debt totaling $7.8 billion at December 31, 2013 and $4.8 billion at December 31, 2012, with none maturing before 2016. We also had $134 million of long-term investments in fixed income securities at December 31, 2013 with maturities that extend through November 2016.

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. We hold a series of interest rate swaps relating to three of our debt instruments with a total notional amount of $1.5 billion at a weighted-average, LIBOR-based, floating rate of 3.8% as of December 31, 2013. 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 is included in "Other assets" in our consolidated balance sheets as of December 31, 2013 and December 31, 2012. 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 (Level 2). These derivative instruments are marked to market with gains and losses recognized currently in interest expense to offset the respective gains and losses recognized on changes in the fair value of the hedged debt. At December 31, 2013, we had fixed rate debt aggregating $6.3 billion and variable rate debt aggregating $1.5 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 fixed income securities, and trade receivables. It is our practice to place our cash equivalents and investments in fixed income 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. As of December 31, 2013, 34% of our gross trade receivables were in the United States and 8% were in Venezuela, compared to 36% in the United States and 9% in Venezuela at December 31, 2012. 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 14. 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 $313 million in 2013, $293 million in 2012, and $245 million in 2011;
- 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 plans other than pensions 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, 2013, the projected benefit obligation was $1.2 billion and the fair value of plan assets was $887 million, which resulted in an unfunded obligation of $268 million. At December 31, 2012, the projected benefit obligation was $1.0 billion and the fair value of plan assets was $754 million, which resulted in an unfunded obligation of $276 million. The accumulated benefit obligation for our international plans was $1.1 billion at December 31, 2013 and $961 million at December 31, 2012.

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

	December 31	
Millions of dollars	2013	2012
Amounts recognized on the Consolidated Balance Sheets		
Accrued employee compensation and benefits	$ 17	$ 10
Employee compensation and benefits	251	266
Pension plans in which projected benefit obligation exceeded plan assets		
Projected benefit obligation	$ 1,123	$ 1,004
Fair value of plan assets	854	727
Pension plans in which accumulated benefit obligation exceeded plan assets		
Accumulated benefit obligation	$ 1,046	$ 935
Fair value of plan assets	854	726

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	Level 1	Level 2	Level 3	Total
Common/collective trust funds (a)				
Equity funds	$ —	$ 247	$ —	$ 247
Bond funds	—	118	—	118
Balanced funds	—	13	—	13
Non-United States equity securities	165	—	—	165
United States equity securities	139	—	—	139
Corporate bonds	—	110	—	110
Other assets	2	59	34	95
Fair value of plan assets at December 31, 2013	$ 306	$ 547	$ 34	$ 887
Common/collective trust funds (a)				
Equity funds	$ —	$ 204	$ —	$ 204
Bond funds	—	112	—	112
Balanced funds	—	13	—	13
Non-United States equity securities	130	—	—	130
United States equity securities	110	—	—	110
Corporate bonds	—	107	—	107
Other assets	27	16	35	78
Fair value of plan assets at December 31, 2012	$ 267	$ 452	$ 35	$ 754

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

Our Level 1 plan asset fair values are based on quoted prices in active markets for identical assets, our Level 2 plan asset fair values are based on significant observable inputs for similar assets, and our Level 3 plan asset fair values are based on significant unobservable inputs.

Equity securities are traded in active markets and valued based on their quoted fair value by independent pricing vendors. Corporate bonds are valued using quotes from independent pricing vendors based on recent trading activity and other relevant information, including other observable inputs such as 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 81% of our international pension plans' projected benefit obligation at December 31, 2013, the target asset allocation during 2013 and 2012 was 65% equity securities and 35% fixed income securities. Beginning in 2014, we are implementing a de-risking program intended to improve the funded status, with the plan's assets increasingly invested over time in low-risk fixed income securities.

Net periodic benefit cost

Net periodic benefit cost for our international pension plans was $32 million in 2013, $26 million in 2012, and $27 million in 2011.

Actuarial assumptions

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

	2013	2012
Discount rate	4.8%	4.8%
Rate of compensation increase	5.5%	5.5%

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:

	2013	2012	2011
Discount rate	4.8%	5.2%	7.1%
Expected long-term return on plan assets	6.4%	6.5%	5.7%
Rate of compensation increase	5.5%	5.4%	6.2%

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.

Other information

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 $17 million to our international pension plans in 2014.

Benefit payments. Expected benefit payments over the next 10 years are approximately $40 million annually for our international pension plans.

Note 15. Accounting Standards Recently Adopted

In February 2013, the Financial Accounting Standards Board issued an update to existing guidance on the presentation of comprehensive income. This update requires companies to report the effect of significant reclassifications out of accumulated other comprehensive income (AOCI) by component. For significant items reclassified out of AOCI to net income in their entirety during the reporting period, companies must report the effect on the line items in the statement where net income is presented. For significant items not reclassified to net income in their entirety during the period, companies must provide cross-references in the notes to other disclosures that already provide information about those amounts. We adopted this update effective January 1, 2013, and it did not have a material impact on our consolidated financial statements.

HALLIBURTON COMPANY
Selected Financial Data
(Unaudited)

Millions of dollars and shares except per share and employee data	Year ended December 31 2013	2012	2011	2010	2009
Total revenue	$ 29,402	$ 28,503	$ 24,829	$ 17,973	$ 14,675
Total operating income	$ 3,138	$ 4,159	$ 4,737	$ 3,009	$ 1,994
Nonoperating expense, net	(374)	(337)	(288)	(354)	(312)
Income from continuing operations before income taxes	2,764	3,822	4,449	2,655	1,682
Provision for income taxes	(648)	(1,235)	(1,439)	(853)	(518)
Income from continuing operations	$ 2,116	$ 2,587	$ 3,010	$ 1,802	$ 1,164
Income (loss) from discontinued operations, net	19	58	(166)	40	(9)
Net income	$ 2,135	$ 2,645	$ 2,844	$ 1,842	$ 1,155
Noncontrolling interest in net income of subsidiaries	(10)	(10)	(5)	(7)	(10)
Net income attributable to company	$ 2,125	$ 2,635	$ 2,839	$ 1,835	$ 1,145
Amounts attributable to company shareholders:					
Income from continuing operations	$ 2,106	$ 2,577	$ 3,005	$ 1,795	$ 1,154
Income (loss) from discontinued operations, net	19	58	(166)	40	(9)
Net income	2,125	2,635	2,839	1,835	1,145
Basic income per share attributable to shareholders:					
Income from continuing operations	$ 2.35	$ 2.78	$ 3.27	$ 1.98	$ 1.28
Net income	2.37	2.85	3.09	2.02	1.27
Diluted income per share attributable to shareholders:					
Income from continuing operations	2.33	2.78	3.26	1.97	1.28
Net income	2.36	2.84	3.08	2.01	1.27
Cash dividends per share	0.525	0.36	0.36	0.36	0.36
Return on average shareholders' equity	14.45%	18.17%	24.06%	19.17%	13.88%
Financial position:					
Net working capital	$ 8,678	$ 8,334	$ 7,456	$ 6,129	$ 5,749
Total assets	29,223	27,410	23,677	18,297	16,538
Property, plant, and equipment, net	11,322	10,257	8,492	6,842	5,759
Long-term debt (including current maturities)	7,816	4,820	4,820	3,824	4,574
Total shareholders' equity	13,615	15,790	13,216	10,387	8,757
Total capitalization	21,569	20,764	18,097	14,241	13,331
Basic weighted average common shares outstanding	898	926	918	908	900
Diluted weighted average common shares outstanding	902	928	922	911	902
Other financial data:					
Capital expenditures	$ 2,934	$ 3,566	$ 2,953	$ 2,069	$ 1,864
Long-term borrowings (repayments), net	2,968	—	978	(790)	1,944
Depreciation, depletion, and amortization	1,900	1,628	1,359	1,119	931
Payroll and employee benefits	8,421	7,722	6,756	5,370	4,783
Number of employees	77,000	73,000	68,000	58,000	51,000

HALLIBURTON COMPANY
Quarterly Data and Market Price Information
(Unaudited)

Millions of dollars except per share data	Quarter First [1]	Second	Third	Fourth	Year
2013					
Revenue	$ 6,974	$ 7,317	$ 7,472	$ 7,639	$ 29,402
Operating income (loss)	(98)	984	1,108	1,144	3,138
Net income (loss)	(16)	648	708	795	2,135
Amounts attributable to company shareholders:					
Income (loss) from continuing operations	(13)	642	707	770	2,106
Income (loss) from discontinued operations	(5)	2	(1)	23	19
Net income (loss) attributable to company	(18)	644	706	793	2,125
Basic income per share attributable to company shareholders:					
Income (loss) from continuing operations	(0.01)	0.69	0.79	0.91	2.35
Income (loss) from discontinued operations	(0.01)	0.01	—	0.02	0.02
Net income (loss)	(0.02)	0.70	0.79	0.93	2.37
Diluted income per share attributable to company shareholders:					
Income (loss) from continuing operations	(0.01)	0.69	0.79	0.90	2.33
Income (loss) from discontinued operations	(0.01)	—	—	0.03	0.03
Net income (loss)	(0.02)	0.69	0.79	0.93	2.36
Cash dividends paid per share	0.125	0.125	0.125	0.15	0.525
Common stock prices [2]					
High	43.96	45.75	50.50	56.52	56.52
Low	35.07	36.77	41.86	47.99	35.07
2012					
Revenue	$ 6,868	$ 7,234	$ 7,111	$ 7,290	$ 28,503
Operating income	1,023	1,201	954	981	4,159
Net income	630	739	604	672	2,645
Amounts attributable to company shareholders:					
Income from continuing operations	635	745	608	589	2,577
Income (loss) from discontinued operations	(8)	(8)	(6)	80	58
Net income attributable to company	627	737	602	669	2,635
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.69	0.81	0.66	0.63	2.78
Income (loss) from discontinued operations	(0.01)	(0.01)	(0.01)	0.09	0.07
Net income	0.68	0.80	0.65	0.72	2.85
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.69	0.80	0.65	0.63	2.78
Income (loss) from discontinued operations	(0.01)	(0.01)	—	0.09	0.06
Net income	0.68	0.79	0.65	0.72	2.84
Cash dividends paid per share	0.09	0.09	0.09	0.09	0.36
Common stock prices [2]					
High	39.19	35.32	38.00	36.00	39.19
Low	32.02	26.28	27.62	29.83	26.28

(1) Includes a $1.0 billion, pre-tax, charge in the first quarter of 2013, and a $300 million, pre-tax, charge in the first quarter of 2012 related to the Macondo well incident.
(2) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 3 through 4 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table," "Grants of Plan-Based Awards in Fiscal 2013," "Outstanding Equity Awards at Fiscal Year End 2013," "2013 Option Exercises and Stock Vested," "2013 Nonqualified Deferred Compensation," "Employment Contracts and Change-in-Control Arrangements," "Post-Termination or Change-in-Control 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 2014 Annual Meeting of Stockholders (File No. 001-03492) 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 Halliburton Company as required by Part II, Item 8, are included on pages 40 and 41 and pages 42 through 72 of this annual report. See index on page (i).

2. Financial Statement Schedules:

   The schedules listed in Rule 5-04 of Regulation S-X (17 CFR 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. 001-03492).
3.2	By-laws of Halliburton Company revised effective July 18, 2013 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed July 19, 2013, File No. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).

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. 001-03492).

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. 001-03492).

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. 001-03492).

4.9 Copies of instruments that define the rights of holders of miscellaneous long-term notes of Halliburton Company and its subsidiaries have not been filed with the Commission. Halliburton Company agrees to furnish copies of these instruments upon request.

4.10 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. 001-03492).

4.11 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).

4.12 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. 001-03492).

4.13 Third Supplemental Indenture dated as of December 12, 2003 among DII Industries, LLC, Halliburton Company 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. 001-03492).

4.14 Indenture dated as of October 17, 2003 between Halliburton Company 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. 001-03492).

4.15 Second Supplemental Indenture dated as of December 15, 2003 between Halliburton Company 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. 001-03492).

4.16 Form of note of 7.6% debentures due 2096 (included as Exhibit A to Exhibit 4.15 above).

4.17 Fourth Supplemental Indenture, dated as of September 12, 2008, between Halliburton Company 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. 001-03492).

4.18 Form of Global Note for Halliburton's 5.90% Senior Notes due 2018 (included as part of Exhibit 4.17).

	4.19	Form of Global Note for Halliburton’s 6.70% Senior Notes due 2038 (included as part of Exhibit 4.17).
	4.20	Fifth Supplemental Indenture, dated as of March 13, 2009, between Halliburton Company 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. 001-03492).
	4.21	Form of Global Note for Halliburton’s 6.15% Senior Notes due 2019 (included as part of Exhibit 4.20).
	4.22	Form of Global Note for Halliburton’s 7.45% Senior Notes due 2039 (included as part of Exhibit 4.20).
	4.23	Sixth Supplemental Indenture, dated as of November 14, 2011, between Halliburton Company 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. 001-03492).
	4.24	Form of Global Note for Halliburton’s 3.25% Senior Notes due 2021 (included as part of Exhibit 4.23).
	4.25	Form of Global Note for Halliburton’s 4.50% Senior Notes due 2041 (included as part of Exhibit 4.23).
	4.26	Seventh Supplemental Indenture, dated as of August 5, 2013, between Halliburton Company and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank (incorporated by reference to Exhibit 4.2 of Halliburton’s Form 8-K filed August 5, 2013, File No. 001-03492).
	4.27	Form of Global Note for Halliburton’s 1.00% Senior Notes due 2016 (included as part of Exhibit 4.26).
	4.28	Form of Global Note for Halliburton’s 2.00% Senior Notes due 2018 (included as part of Exhibit 4.26).
	4.29	Form of Global Note for Halliburton’s 3.50% Senior Notes due 2023 (included as part of Exhibit 4.26).
	4.30	Form of Global Note for Halliburton’s 4.75% Senior Notes due 2043 (included as part of Exhibit 4.26).
†	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. 001-03492).
†	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. 001-03492).
†	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. 001-03492).

†	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. 001-03492).
†	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. 001-03492).
	10.8	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. 001-03492).
	10.9	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. 001-03492).
	10.10	Form of Indemnification Agreement for Officers (first elected after January 1, 2013) (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).
	10.11	Form of Indemnification Agreement for Directors (first elected after January 1, 2013) (incorporated by reference to Exhibit 10.1 of Halliburton's Form 8-K filed March 22, 2013, File No. 001-03492).
†	10.12	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. 001-03492).
†	10.13	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. 001-03492).
†	10.14	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. 001-03492).
†	10.15	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. 001-03492).
†	10.16	Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective as of May 16, 2012 (incorporated by reference to Exhibit 10.5 to Halliburton's Form 10-Q for the quarter ended June 30, 2012, File No. 001-03492).
†	10.17	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. 001-03492).
†	10.18	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. 001-03492).
†	10.19	Executive Agreement (Lawrence J. Pope) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed December 12, 2008, File No. 001-03492).
†	10.20	Halliburton Company Stock and Incentive Plan, as amended and restated effective February 20, 2013 (incorporated by reference to Appendix B of Halliburton's proxy statement filed April 2, 2013, File No. 001-03492).

†	10.21	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. 001-03492).
†	10.22	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. 001-03492).
†	10.23	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. 001-03492).
†	10.24	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. 001-03492).
†	10.25	Form of Non-Employee Director Restricted Stock Unit Agreement (Director Plan) (incorporated by reference to Exhibit 99.8 of Halliburton's Form S-8 filed June 22, 2012, Registration No. 333-182284).
†	10.26	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. 001-03492).
†	10.27	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. 001-03492).
†	10.28	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. 001-03492).
†	10.29	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. 001-03492).
†	10.30	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. 001-03492).
†	10.31	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. 001-03492).
†	10.32	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. 001-03492).
	10.33	U.S. $2,000,000,000 Five Year Revolving Credit Agreement among Halliburton Company, 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. 001-03492).
†	10.34	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. 001-03492).
†	10.35	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. 001-03492).

†	10.36	Executive Agreement (Christian A. Garcia) (incorporated by reference to Exhibit 10.40 to Halliburton’s Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.37	First Amendment to Halliburton Company Restricted Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.41 to Halliburton’s Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.38	Form of Restricted Stock Agreement (Section 16 officers) (incorporated by reference to Exhibit 10.42 to Halliburton’s Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.39	Form of Non-Employee Director Restricted Stock Unit Agreement (Stock and Incentive Plan) (incorporated by reference to Exhibit 99.9 of Halliburton's Form S-8 filed June 22, 2012, Registration No. 333-182284).
†	10.40	Second Amendment to Restricted Stock Plan for Non-Employee Directors of Halliburton Company (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended June 30, 2012, File No. 001-03492).
†	10.41	Third Amendment to Restricted Stock Plan for Non-Employee Directors of Halliburton Company effective December 1, 2012 (incorporated by reference to Exhibit 10.44 to Halliburton’s Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.42	First Amendment dated December 1, 2012 to Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective May 16, 2012 (incorporated by reference to Exhibit 10.45 to Halliburton’s Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.43	Executive Agreement (Jeffrey A. Miller) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed September 21, 2012, File No. 001-03492).
†	10.44	Second Amendment dated December 11, 2012 to Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Exhibit 10.47 to Halliburton’s Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.45	Executive Agreement (Myrtle L. Jones) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).
†	10.46	First Amendment dated April 23, 2013 of the Five Year Revolving Credit Agreement among Halliburton Company, as Borrower, the Banks party thereto, and Citibank, N.A., as Agent effective February 22, 2011 (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).
	10.47	Underwriting Agreement, dated July 29, 2013, among Halliburton Company and Citigroup Global Markets Inc., Deutsche Bank Securities Inc., HSBC Securities (USA) Inc., RBS Securities Inc. and the several other underwriters identified therein (incorporated by reference to Exhibit 1.1 of Halliburton’s Form 8-K filed August 1, 2013, File No. 001-03492).
*†	10.48	Executive Agreement (Robb L. Voyles).
*†	10.49	Executive Agreement (Timothy McKeon).
*	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 January 2014: Alan M. Bennett James R. Boyd Milton Carroll Nance K. Dicciani Murry S. Gerber José C. Grubisich 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.
† Management contracts or compensatory plans or arrangements.

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 7th day of February, 2014.

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 7th day of February, 2014.

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/ Christian A. Garcia Christian A. Garcia	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
* José C. Grubisich José C. Grubisich	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
*By Christina M. Ibrahim, Attorney-in-fact

SHAREHOLDER INFORMATION //

Shares Listed

New York Stock Exchange
Symbol: HAL

Transfer Agent and Registrar

Computershare
P.O. Box 30170
College Station, Texas 77842-3170
Telephone: 800.279.1227
www.computershare.com/investor

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

This annual report is printed on environmentally responsible paper, which is FSC-certified (portions of which are 100% post-consumer recycled paper).

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HALLIBURTON

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