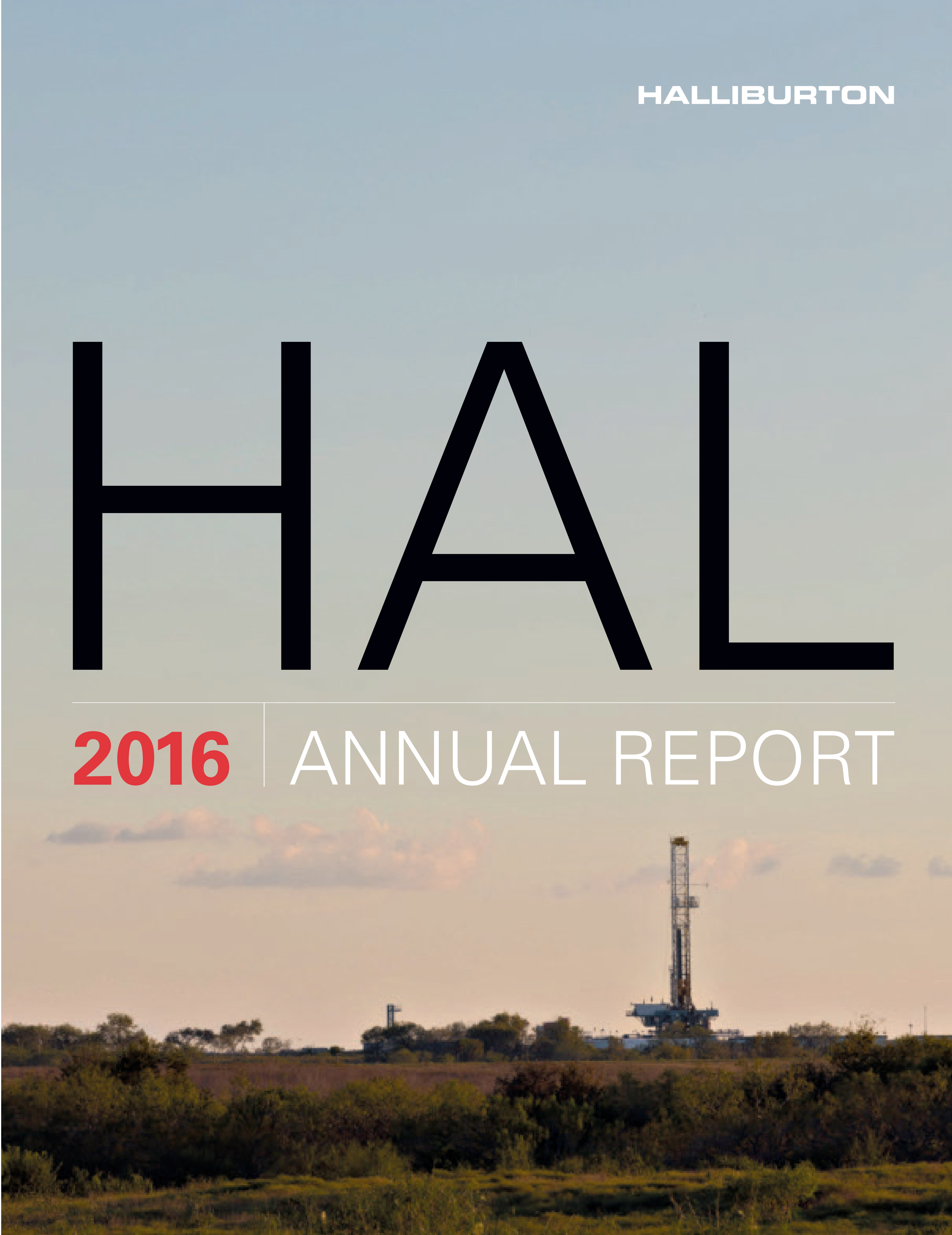
HALLIBURTON

# HAL

## 2016 ANNUAL REPORT




**Halliburton's strategy is built on delivering the lowest cost per barrel of oil equivalent, which means delivering effective and efficient solutions employing technology responsive to customers' requirements.**

# Financial Highlights

| (Millions of dollars and shares, except per share data) | 2016[1] | 2015[1] | 2014 |
|---|---|---|---|
| Revenue | **$ 15,887** | $ 23,633 | $ 32,870 |
| Operating Income (Loss) | **$ (6,778)** | $ (165) | $ 5,097 |
| Amounts Attributable to Company Shareholders: | | | |
| Income (Loss) from Continuing Operations | **$ (5,761)** | $ (666) | $ 3,436 |
| Net Income (Loss) | **$ (5,763)** | $ (671) | $ 3,500 |
| Diluted Income per Share Attributable to Company Shareholders: | | | |
| Income (Loss) from Continuing Operations | **$ (6.69)** | $ (0.78) | $ 4.03 |
| Net Income (Loss) | **$ (6.69)** | $ (0.79) | $ 4.11 |
| Cash Dividends per Share | **$ 0.72** | $ 0.72 | $ 0.63 |
| Diluted Common Shares Outstanding | **861** | 853 | 852 |
| Working Capital[2] | **$ 7,654** | $ 14,733 | $ 8,781 |
| Capital Expenditures | **$ 798** | $ 2,184 | $ 3,283 |
| Long-Term Debt, including Currrent Maturities | **$ 12,377** | $ 15,346 | $ 7,779 |
| Debt to Total Capitalization[3] | **57%** | 50% | 33% |
| Depreciation, Depletion and Amortization | **$ 1,503** | $ 1,835 | $ 2,126 |
| Return on Average Capital Employed[4] | **(20)%** | (1)% | 17% |
| Total Capitalization[5] | **$ 21,832** | $ 30,850 | $ 24,196 |

[1] Reported losses during these periods were primarily due to Baker Hughes related costs and termination fee of $4.1 billion and impairments and other charges of $3.4 billion for the year ended December 31, 2016, and impairments and other charges of $2.2 billion for the year ended December 31, 2015.

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

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

[4] 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.

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

**Revenue**
in billions

**$32.9**
2014

**$23.6**
2015

**$15.9**
**2016**

**Dividends to Shareholders**
in millions

**$533**
2014

**$614**
2015

**$620**
**2016**

**Capital Expenditures**
in billions

**$3.3**
2014

**$2.2**
2015

**$0.8**
**2016**

## To Our Shareholders

**In 2016, despite a turbulent year in the oil and gas industry, Halliburton increased market share by collaborating with our customers, adapting to market changes and maintaining our superior service quality. By remaining centered on our customers' needs, reducing structural costs and focusing on efficient use of our assets, Halliburton successfully navigated the downturn and is well-positioned for the recovery.**

Our playbook during this cycle was built on Halliburton's strengths: We are the execution company, with the best employees, technology and service offerings to deliver on our value proposition – collaborating and engineering solutions to maximize asset value for our customers. Over the course of the year, we eliminated $1 billion of structural costs and worked to live within our cash flow. This tremendous effort did not come without sacrifice, but it positions Halliburton for the global recovery.

In North America, the oil and gas industry went through a historic cycle, punctuated by an almost 80 percent decline in the U.S. land rig count. During this downturn Halliburton gained significant market share. As a result, after the market bottomed in North America midway through the year, we were able to utilize this historically high share to drive margin improvement and return to profitability in the fourth quarter.

**"We are the execution company, with the best employees, technology and service offerings to deliver on our value proposition – collaborating and engineering solutions to maximize asset value for our customers."**

As activity increases in North America, we do not expect to rely on rising service pricing alone to earn returns. We recognize that North America's emergence as the world's swing producer could mean that cycles may be shorter and commodity prices may be range bound – not as low as they were during the downturn, but not as high as they were during the last up cycle. As a result, we plan to make more effective use of our assets through greater asset velocity to increase margins. We will be leaner, avoid over-investing and remain flexible in our cost structure.

As the recovery began to unfold in North America, we continued to experience headwinds in our international markets. Low commodity prices stressed our customers' capital budgets and impacted economics across the international deepwater and mature field markets, resulting in decreased activity and pricing throughout 2016. We expect to see improved activity in mature fields – where much of the world's oil is produced – and believe that this market will lead the international recovery in late 2017. While the deepwater market has been the most challenged during the downturn, we continue to work with our customers as we wait for this market to improve.

Ultimately, stronger and more stable commodity prices will help free our customers from the cage of limited cash flows and enable them to increase investment. This will lead to greater utilization of our services and equipment and generate greater returns. The fundamentals of the macro market have not changed and the last few years of underinvestment means that in the coming upcycle more work will have to be put into fighting decline curves as global demand begins to once again outpace supply.

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

eighty+

WE COLLABORATED WITH CUSTOMERS
on more than 80 research and development projects in 2016, innovating to meet their specific needs.

**$1B**

WE SUCCEEDED IN MAKING **STRUCTURAL COST REDUCTIONS** OF $1 BILLION IN 2016.

**7.5**
**PERCENT REDUCTION**
In 2016, we reduced our TOTAL RECORDABLE INCIDENT RATE by 7.5 percent.

5
**Consecutive Years**

FIVE CONSECUTIVE YEARS OF IMPROVEMENT IN HEALTH, SAFETY AND INCIDENT RATES.

59% TOTAL SHAREHOLDER **RETURN**

As we move forward, our strategy remains the same. We will deliver superior growth, margins and returns by executing on our core strategies in the unconventionals, deepwater and mature fields markets. We will provide our products, services and technologies to customers in the most important oil and gas basins in North America and across the globe. We will collaborate with our customers in their efforts to maximize their asset value and remain focused on integrity, efficiency, safety and service quality. We will grow our service capability by addressing service lines one building block at a time through internal growth, investment and selective acquisitions.

Halliburton's 98th year in business was consequential for the company and the industry. Our employees, management and Board of Directors persevered during difficult times. As we enter our 99th year, we remain steadfast in our commitment to deliver reliable execution and industry-leading growth, margins and returns. We appreciate the confidence placed in us by our customers as we work together to find efficient, cost-effective and safe means to achieve their goals, as well as the support of our investors who have remained with us through these challenging times.

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

**Jeffrey A. Miller**
President and Chief Health, Safety and Environment Officer

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

**Robb L. Voyles**
Executive Vice President, Interim Chief Financial Officer, Secretary and General Counsel

**Eric J. Carre**
Executive Vice President, Global Business Lines

**James S. Brown**
President, Western Hemisphere

**Joe D. Rainey**
President, Eastern Hemisphere

# NORTH AMERICA

$ 6.8 BILLION in REVENUE

AVG 8M LBS SAND PER WELL

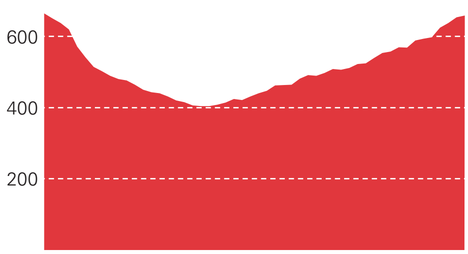
**59%** YEAR-OVER-YEAR GROWTH IN SAND

**GULF** OF **MEXICO** REPRESENTS **15%** OF **REVENUE**

**9%** SEQUENTIAL **GROWTH** **in fourth quarter 2016**

# North America

**U.S. Land Rig Count**
January – December 2016




This year was punctuated with the U.S. land rig count bottoming in the second quarter, ending the year just below where it started with approximately 670 rigs.

**Spotlight**

Halliburton completed a hydraulic fracturing job for Eclipse Resources on the longest horizontal onshore lateral ever drilled in the U.S. The total well depth, including lateral extension, was 27,046 feet. The Utica Shale well has a lateral length of over 18,500 feet and was completed with 124 frac stages in 24 days. The Halliburton and Eclipse team worked incredibly efficiently together, setting 124 Obsidian® Frac plugs, averaging 5.3 frac stages per day and achieving a North America land record of 26,641 feet in plug set depth. This accomplishment was made using our Frac of the Future fleet, including dual fuel engine capability that reduced fuel consumption by 40 percent. The efficiencies achieved with this equipment allowed Eclipse to improve its daily completion rate by 20 percent and created production across the entire length of the lateral, leading to best-in-class production and cost results.

**During 2016, Halliburton weathered the deep cyclical downturn in North America – and gained significant market share – because we helped our customers increase the efficiency of their operations through the quality of our services and superior technology.**

The industry saw unprecedented declines in rig count until it reached the bottom of the cycle at the end of the second quarter. From there, we managed a steady growth in rig count and activity, which allowed us to increase our utilization and return to profitability by the fourth quarter. When low commodity prices squeezed operators' capital budgets, we helped them reduce the cost of each barrel of oil equivalent by driving down costs, improving productivity and increasing the ultimate recovery from their wells.

Halliburton demonstrated its value proposition – collaborating and engineering solutions to maximize asset value for our customers – while working with a customer in the Williston Basin that wanted to drill an 830-foot curve section of a horizontal well in the fastest time possible while maintaining drill bit control. The local team determined that the well was a prime candidate for the Halliburton Cruzer™ depth of cut rolling element, which provides reliable drilling efficiency by stabilizing the bit's cutting action. Cruzer also maintains consistent depth of cut and lowers the coefficient of friction, creating less torque and heat generation as compared to conventional technologies. The solution reduced overall drilling costs for the operator because the curve section was drilled in just 9.5 hours of on-bottom drilling time, as well as achieving the fastest rate of penetration and lowest cost per foot among offsets on the well pad.

As operators ramp up activity coming out of the downturn, we are seeing a combination of increased land rig drilling efficiency, longer average lateral lengths for wells and increased completion intensity. These three factors have a compounding effect that consumes more horsepower per rig than in previous cycles. Today, we are pumping more sand than ever before – on average, more than 8 million pounds per well – and Halliburton's Q10™ pressure pumping technology, which is the centerpiece of the Frac of the Future, is designed specifically to operate in these conditions.

Our surface efficiency focus was highlighted with an operator in the Bakken who turned to Halliburton to reduce significant non-productive time resulting from costly third-party zipper manifold maintenance, leaks and failure. Halliburton utilized its ExpressKinect™ Wellhead Connection Unit to displace the third-party zipper manifold and eliminate the source of delays; this improved cycle times by 50 percent and enabled the wells to be completed faster.

Subsurface insight and custom chemistry also set Halliburton apart from the competition. Multi-Chem utilized a combination of subsurface insight and chemistry to create a custom solution for a Permian customer struggling to get adequate production due to absorption of traditional surfactants by the clay and carbonate rock. The tailored chemical solution included a proprietary surfactant that prevents absorption, allowing the surfactant to reach deeper in the rock and drive increased oil recovery. As a result, initial production was 40 percent higher than offset wells in the same area and this improved incremental production more than offset the cost of the custom solution.

These examples illustrate ways in which Halliburton leads the industry by working with customers to engineer solutions to drive down costs and improve production at every step of drilling and completing wells. Halliburton brings a systematic approach to listening and responding to our customers' needs that results in the most efficient technology, removing waste in the last mile and relentlessly focusing on high-quality, efficient execution.

# INTERNATIONAL

**33%** REDUCTION

**LOST-TIME INCIDENT RATE**
across our international regions

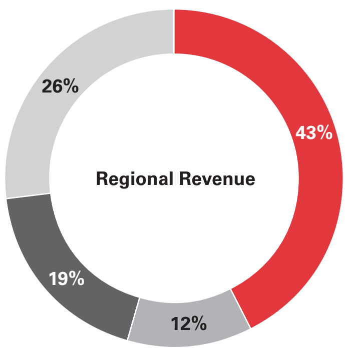
**70%** OF THE WORLD'S OIL & GAS PRODUCTION IS FROM **MATURE FIELDS**

**90 PERCENT**
Average Nationalized Workforce

**62%** INTERNATIONAL REVENUE FROM **LAND-BASED OPERATIONS**

## International

**With operations in approximately 70 countries, Halliburton's services, technology and execution provide a strong platform for growth across every region of the world. Our value proposition to lower the cost per barrel of oil equivalent through collaboration and engineering solutions resonates with our customers and has led to increased business across the globe.**




- North America
- Latin America
- Europe/Africa/CIS
- Middle East/Asia

Our international footprint showed its strength in 2016 accounting for 57 percent of our total revenue.

Our international market presence is driven by two important market segments, mature fields and deepwater. Approximately 70 percent of global oil production today is mature fields-based, which serves as a major element of Halliburton's international operations. This segment was the most resilient throughout 2016, although at lower activity levels and with increased pricing pressure.

When working in mature fields, it is important to understand the stage of production of the developed field, while learning from the work that was previously completed to better optimize the field for further production. We work with our customers in mature fields to increase recovery rates and find bypassed pay; frequently applying recent innovations to fight declining production rates.

In Azerbaijan, Halliburton helped a customer by developing a custom perforating solution that used the Dominator® shaped charge system specifically tuned for the customer's reservoir conditions and achieved a 14 percent improvement in performance in the second phase of field development. This project led to a multi-year, multi-well award for continued work in Azerbaijan. It is a great example of how Halliburton listens to our customers to engineer solutions that optimize results.

A customer in the Middle East was seeking an optimal field development plan for over 200 wells. Halliburton Consulting and Project Management collaborated with the customer to identify the optimal plan. New well locations were optimized for drilling using Halliburton's patented Well Placement Optimization methodology. The coordinated plan was built with production assurance from DecisionSpace™ Assisted History Matching, which uses reservoir data collected over time to create predictive models. The approach increased the reservoir original oil in place by 17 percent and increased the estimated ultimate recovery factor from 26 percent to 37 percent, exceeding the customer's expectation by 5 percent. This project demonstrates how Halliburton can work with our customers, using both historical data and new technology to achieve their goals at any scale.

While the deepwater segment remains challenged, Halliburton is committed to our customers with deepwater activities and our extensive global footprint positions us well for the eventual upturn.

An example of deepwater offshore work today is the project we are executing in Brazil's Libra field. Halliburton helped our customer drill a difficult section of a well with a narrow pressure window. Halliburton installed automated GeoBalance® Managed Pressure Drilling on the drillship and developed a collaborative solution with the rig operator and customer for a difficult salt zone. As a result, we drilled four sections totaling 3,785 meters with zero nonproductive time, saving the customer $30 million as compared to traditional drilling methods. This cost savings improved the project economics and maximized the asset value.

In 2016, activity in the international market was region-specific; there were historic lows in rig counts in some regions while others maintained high activity. Our strategy has adapted to these challenges and we are poised to handle future market challenges as we prepare for the international market recovery.

**"Overall, our 2016 results show that we have executed in a challenging market. Guided by the lessons learned from past industry cycles, our strategy focused not only on managing costs, but also on aligning our resources to strengthen our market position and I think we've done that."**

CEO Dave Lesar,
Fourth Quarter Earnings Call

# TECHNOLOGY

**590**

**Patents granted in 2016, a 19% increase over 2015**

INDUSTRY-LEADING

**38**

API Q2 Certifications

**55%**

**SEQUENTIAL REDUCTION**

IN COST OF POOR QUALITY

# Technology

**Halliburton's approach to technology emphasizes reliability, simplicity and cost. Ideas emerge from collaborations with our customers, our field personnel and a deep technical bench rooted in 15 technology centers spread around the globe. On a cost per patent basis – an important measure of research and development efficiency – we go head to head with the best in any industry sector. Our disciplined approach to developing differentiated solutions is recognized by both our customers and the industry. The following exemplifies our most recognized technology differentiators in 2016:**

2016 Offshore Technology Conference – Spotlight on New Technology Winners

**BaraLogix™ Density & Rheology Unit (DRU)**

We broke down barriers to deliver a single piece of equipment that can autonomously measure fluid density and rheology in real-time. The BaraLogix™ DRU can be added to any drilling program. The frequent and accurate data collection helps identify trends in the drilling fluid properties that are unavailable with current rig site resources, providing unmatched accuracy and reliability to help reduce risk, increase efficiency and communicate performance.

**CoreVault®**

Built into the proven Xaminer® Coring Tool, our CoreVault® system can capture up to 10 samples in a sealed container – in one run. By preserving 100 percent of the fluids within the core sample, we are able to define critical fluid properties, including bubblepoint or saturation pressure of hydrocarbons in the reservoir. This enables accurate simulation of production – a world's first for the industry.

*World Oil* Awards 2016

**Integrated Sensor Diagnostics Service** – *Best Production Technology*

Integrated sensor diagnostics (ISD) service combines subsurface insight with far-field and near wellbore sensors data collected throughout a well's life. This knowledge is integrated with proven fracture and reservoir engineering techniques to help make financially important decisions relating to well spacing, fracture spacing and completion design.

**DES DrillingXpert™ Software Integrated Sensor Diagnostics Service** – *Best Visualization & Collaboration*

DrillingXpert™ software provides our experts the ability to design an entire drilling system in one advanced package, reducing planning time and improving decision making by providing access to all required information in a single location. This well-engineering software tool kit is unparalleled in the industry and increases collaboration between Halliburton and its customers in the drilling process.

**Quasar Trio™ Service** – *Best Drilling Technology*

The Quasar Trio™ M/LWD Triple-Combo Service brings together three high-grade sensors for accurate data collection in extreme-temperature environments. The three rugged sensors capture resistivity, azimuthal density and neutron porosity measurements with the same accuracy as standard-temperature sensors, providing real-time data to optimize drilling, reservoir characterization and production. No other commercially available M/LWD system can yield comprehensive measurements at such temperatures.

2016 Hart's Meritorious Engineering Achievement Awards

**SmartPlex® Downhole Control System**

The SmartPlex® downhole control system remotely actuates downhole control devices using electro-hydraulic control lines from the surface. This multi-drop system provides simple and reliable zonal control of up to 12 interval control valves in a single wellbore, with a minimum number of the control lines reducing operational time, complexity and risk.

**The Advanced Perforating Flow Laboratory at the Halliburton Jet Research Center**

For more than ten years, Halliburton has conducted tests tailored specifically to our customers' needs to help better understand downhole conditions and perforating system performance. This facility is as close to the real world as you can get in a laboratory setting making it an industry leader in perforating system research, development and test programs.

# Leadership

## Board of Directors

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

**Abdulaziz F. Al Khayyal**
Retired Senior Vice President of Industrial Relations,
Saudi Aramco
(2014) (C) (D)

**William E. Albrecht**
Non-Executive Chairman of the Board,
California Resources Corporation
(2016) (B) (C)

**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**
Non-Executive Chair of the Board,
AgroFresh Solutions, Inc.
(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)

**Robert A. Malone**
Executive Chairman, President and
Chief Executive Officer,
First Sonora Bancshares, Inc.
(2009) (B) (C)

**J. Landis Martin**
Founder,
Platte River Equity
(1998) (C) (D)

**Jeffrey A. Miller**
President and Chief Health, Safety
and Environment Officer,
Halliburton Company
(2014)

**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 and Chief Executive Officer

**Jeffrey A. Miller**
President and Chief Health, Safety and
Environment Officer

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

**Robb L. Voyles**
Executive Vice President, Interim Chief Financial
Officer, Secretary and General Counsel

**Eric J. Carre**
Executive Vice President,
Global Business Lines

**James S. Brown**
President, Western Hemisphere

**Joe D. Rainey**
President, Eastern Hemisphere

**Anne L. Beaty**
Senior Vice President, Finance

**Myrtle L. Jones**
Senior Vice President, Tax

**Charles E. Geer, Jr.**
Vice President and Corporate Controller

**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, 2016**

**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, 2016, determined using the per share closing price on the New York Stock Exchange Composite tape of $45.29 on that date, was approximately $38.8 billion.

As of January 31, 2017, there were 866,933,212 shares of Halliburton Company Common Stock, $2.50 par value per share, outstanding.

Portions of the Halliburton Company Proxy Statement for our 2017 Annual Meeting of Stockholders (File No. 001-03492) are incorporated by reference into Part III of this report.

**HALLIBURTON COMPANY**
**Index to Form 10-K**
**For the Year Ended December 31, 2016**

## 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 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. 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.

*Completion and Production* delivers cementing, stimulation, intervention, pressure control, specialty chemicals, artificial lift and completion services. The segment consists of the following product service lines:

- Production Enhancement: includes 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: involves 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.
- Production Solutions: includes pressure control services such as coiled tubing, hydraulic workover units and downhole tools.
- Pipeline & Process Services: includes pre-commissioning and maintenance services, subsea pipeline services, conventional pipeline services and process services.
- Multi-Chem: includes oilfield production and completion chemicals and services that address production, processing and transportation challenges.
- Artificial Lift: offers electrical submersible pumps and progressive cavity 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 the following product service lines

- 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 that offer directional control for precise wellbore placement while providing important measurements about the characteristics of the drill string and geological formations while drilling wells. 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.
- Wireline and Perforating: includes 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.
- 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.
- Landmark Software and Services: supplies integrated exploration, drilling and production software, and related professional and data management services for the upstream oil and natural gas industry.

- Testing and Subsea: provides 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.
- 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. In addition, well control and prevention services are included.

See Note 4 to the consolidated financial statements for further financial information related to each of our business segments. We have manufacturing operations in various locations, the most significant of which are located in the United States, Canada, Malaysia, Singapore and the United Kingdom.

***Business strategy***

Our value proposition is to collaborate and engineer solutions to maximize asset value for our customers. We strive to achieve superior growth and returns for our shareholders by delivering technology and services that improve efficiency, increase recovery and maximize production for our customers. 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.

For further discussion on our business strategies we plan to continue to execute, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview."

***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 70 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 2016, 2015 and 2014, based on the location of services provided and products sold, 41%, 44% and 51% 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 4 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, changes in foreign currency exchange rates, 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 14 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 $329 million in 2016, $487 million in 2015 and $601 million in 2014. 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 technology covered by patents owned by others, and we license others to utilize technology covered by our patents. 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 typically result in higher activity in the fourth quarter of the year.

***Employees***

At December 31, 2016, we employed approximately 50,000 people worldwide compared to approximately 65,000 at December 31, 2015. At December 31, 2016, 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 9 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 into the rock formation to enable natural gas or oil to move more easily from the rock pores to a production conduit. 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 sometimes design and generally implement a hydraulic fracturing operation to 'stimulate' the well's production, 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 generally supply the proppant (often sand) and at least a portion of the 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 produced or 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 freshwater aquifers or 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. On December 13, 2016, the EPA released a final report, "*Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*" representing the culmination of a six-year study requested by Congress. While the EPA report noted a potential for some impact to drinking water sources caused by hydraulic fracturing, the agency confirmed the overall incidence of impacts is low. Moreover, a number of the areas of potential impact identified in the report involve activities for which we are not generally responsible, such as potential impacts associated with withdrawals of surface water for use as a base fluid and management of wastewater.

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 hydraulic fracturing technologies, which offer our customers a variety of especially 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 that uses ultraviolet light to control the growth of bacteria in hydraulic fracturing fluids, 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 2016, 2015, or 2014. 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, 2017, 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 62) | President, Western Hemisphere of Halliburton Company, since January 2008 |
| * | Eric J. Carre (Age 50) | Executive Vice President, Global Business Lines of Halliburton Company, since May 2016 |
| | | Senior Vice President, Drilling and Evaluation Division of Halliburton Company, June 2011 to April 2016 |
| | Charles E. Geer, Jr. (Age 46) | Vice President and Corporate Controller of Halliburton Company, since January 2015 |
| | | Vice President, Finance of Halliburton Company, December 2013 to December 2014 |
| | | Vice President and Chief Accounting Officer of Select Energy Services, April 2011 to November 2013 |
| | Myrtle L. Jones (Age 57) | 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 63) | Chairman of the Board and Chief Executive Officer of Halliburton Company, since August 2014 |
| | | Chairman of the Board, President and Chief Executive Officer of Halliburton Company, August 2000 to July 2014 |
| * | Mark A. McCollum (Age 57) | Executive Vice President and Chief Financial Officer of Halliburton Company, since July 2016 |
| | | Executive Vice President and Chief Integration Officer of Halliburton Company, January 2015 to June 2016 |
| | | Executive Vice President and Chief Financial Officer of Halliburton Company, January 2008 to December 2014 |

| | | |
|---|---|---|
| | Timothy M. McKeon (Age 44) | Vice President and Treasurer of Halliburton Company, since January 2014<br>Assistant Treasurer of Halliburton Company, September 2011 to December 2013 |
| * | Jeffrey A. Miller (Age 53) | Member of the Board of Directors and President of Halliburton Company, since August 2014<br>Executive Vice President and Chief Operating Officer of Halliburton Company, September 2012 to July 2014<br>Senior Vice President, Global Business Development and Marketing of Halliburton Company, January 2011 to August 2012 |
| * | Lawrence J. Pope (Age 48) | Executive Vice President of Administration and Chief Human Resources Officer of Halliburton Company, since January 2008 |
| | Joe D. Rainey (Age 60) | President, Eastern Hemisphere of Halliburton Company, since January 2011 |
| * | Robb L. Voyles (Age 59) | Executive Vice President, Secretary and General Counsel of Halliburton Company, since May 2015<br>Executive Vice President and General Counsel of Halliburton Company, January 2014 to April 2015<br>Senior Vice President, Law of Halliburton Company, September 2013 to December 2013<br>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.

***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. 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. Crude oil prices have fluctuated significantly since 2014, with West Texas Intermediate (WTI) oil spot prices declining from a high of $108 per barrel in June 2014 to a low of $26 per barrel in February 2016, a level which has not been experienced since 2003. Although crude oil prices increased during the second half of 2016 to a high of $54 per barrel in December 2016, market reports indicate prices are not expected to increase materially in 2017. For more information, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations.”

The prolonged reduction in oil and natural gas prices depressed levels of exploration, development, and production activity in 2015 and 2016, and prolonged further reductions could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition. Should current market conditions worsen or persist for an extended period of time, we may be required to record additional asset impairments. Such a potential impairment charge could have a material adverse impact on our operating results. 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. We also have a small number of integrated projects that have remuneration tied to hydrocarbon production. Reduction in oil and gas prices can affect the overall returns for these projects, either lengthening the time until the expected returns are realized or by impairing the value of the asset.

Factors affecting the prices of oil and natural gas include:

- the level of supply and demand for oil and natural gas;
- 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 ability or willingness of the Organization of Petroleum Exporting Countries (OPEC) to set and maintain oil production levels;
- the level of oil production by non-OPEC countries;
- 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 further 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.

As a result of the decreases in commodity prices, many of our customers reduced capital spending in 2015 and 2016. While customer budgets are slowly increasing in response to improved market conditions, any prolonged further reduction in commodity prices may result in further capital budget reductions in the future.

***Our operations are subject to political and economic instability and risk of government actions 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, other armed conflict, and sanctions;
  - 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 or our operations, 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, cause us to cease operating in certain countries, 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, 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 subject to cyber-attacks that could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.***

Our operations are becoming increasingly dependent on digital technologies and services. We use these technologies for internal purposes, including data storage, processing, and transmissions, as well as in our interactions with customers and suppliers. Digital technologies are 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 of or damage to intellectual property, proprietary or confidential information, or customer, supplier, or employee data; interruption of our business operations; and increased costs required to prevent, respond to, or mitigate cybersecurity attacks. These risks could harm our reputation and our relationships with customers, suppliers, employees, and other third parties, and may result in claims against us. In addition, 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 anti-corruption laws, even though some of 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 have resulted and may in the future result in internal, independent, or government investigations. Violations of anti-corruption laws 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, the shipment of goods, services, and technology across international borders subjects us to extensive trade laws and regulations. Our import activities are governed by the unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the United States, control the export and re-export of certain goods, services and technology and impose related export recordkeeping and reporting obligations. Governments may also impose economic sanctions against certain countries, persons, and entities that may restrict or prohibit transactions involving such countries, persons and entities, which may limit or prevent our conduct of business in certain jurisdictions. During 2014, the United States and European Union imposed sectoral sanctions directed at Russia's oil and gas industry. Among other things, these sanctions restrict the provision of U.S. and EU goods, services, and technology in support of exploration or production for deep water, Arctic offshore, or shale projects that have the potential to produce oil in Russia. These sanctions resulted in our winding down and ending work on two projects in Russia in 2014, and have prevented us from pursuing certain other projects in Russia. Our ability to engage in certain future projects in Russia is dependent upon whether or not our involvement in such projects is restricted under U.S. or EU sanctions laws and the extent to which any of our Russian operations may be subject to those laws. Those laws may change from time to time, and any expansion of sanctions against Russia's oil and gas industry could further hinder our ability to do business in Russia, which could have a material adverse effect on our consolidated results of operations.

The laws and regulations concerning import activity, export recordkeeping and reporting, export control, and economic sanctions are complex and constantly changing. These laws and regulations can cause delays in shipments and unscheduled operational downtime. Moreover, any failure to comply with applicable legal and regulatory trading obligations could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from governmental contracts, seizure of shipments and loss of import and export privileges. 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.***

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 regulations that apply to hydraulic fracturing operations on wells that are subject to federal oil and gas leases and that 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. The Department of Interior has been enjoined from enforcing these regulations by a federal court; however, this decision is being appealed. If they become effective, these regulations would establish additional levels of regulation at the federal level that could lead to operational delays and increased operating costs. The EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of the EPA's study could spur action towards federal or state legislation and regulation of hydraulic fracturing or similar production operations.

At the same time, legislation and/or regulations have been adopted in many 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. Two states (New York and Vermont) have banned the use of high volume hydraulic fracturing. Moreover, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells and hydraulic fracturing, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities. Local jurisdictions in some states have adopted ordinances that restrict or in certain cases prohibit the use of hydraulic fracturing for oil and gas development. 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.

***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.***

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 the Gulf of Mexico for the lease operator, BP Exploration and Production, Inc. (BP). We performed a variety of services on that well for BP. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

Numerous lawsuits relating to the Macondo well incident and alleging damages arising from the blowout were filed against various parties, including BP, Transocean and us, most of which were consolidated in a Multi-District Litigation (MDL) proceeding. In addition, the Bureau of Safety and Environmental Enforcement has issued a notification of Incidents of Noncompliance (INCs) to us relating to the Macondo well incident. We understand that regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation.

Although the MDL proceeding has concluded and we, BP, Transocean and the plaintiff's steering committee in the MDL proceeding have settled all claims against each other, our settlement is subject to court approval and other conditions before it becomes effective. In addition, we have appealed the INCs, but the appeal has been suspended pending final resolution, including appeals, of the MDL. If the MDL court does not approve our settlement, and the MDL liability finding is overturned on appeal, liabilities resulting from the Macondo well incident could have a material adverse effect on our liquidity, consolidated results of operations and consolidated financial condition. We are unable to predict whether or when the court will approve our MDL settlement or whether or when the conditions of our MDL Settlement will be satisfied.

For additional information relating to the Macondo well incident, our MDL Settlement, the status of the MDL and the INCs, see Note 9 to the consolidated financial statements.

***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;
- the use of underground injection wells; and
- the protection of worker safety both onshore and offshore.

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.

***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 70 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 the year. For example, potential United States tax reform could significantly impact our tax expense and the value of our United States deferred tax assets.

***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 that have restricted or limited trading markets for their local currencies. We may accumulate cash in those geographies, but 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, although we have made a provision to income taxes for a portion of our cumulative undistributed foreign earnings, the balance of such foreign earnings and cash we may accumulate in foreign jurisdictions in the future 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 10 to the consolidated financial statements.

***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 or commodity price 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, the risk of delayed payments, and currency risks, 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, which continues to experience significant political and economic turmoil, including the possibility that the Venezuelan government could assume control over our operations and assets. Any delays in receiving payment on our receivables from our primary customer in Venezuela or failure to pay us a significant amount of our outstanding receivables 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 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, such as proppants, hydrochloric acid, and gels, including guar gum, are normally readily available. Shortage of raw materials as a result of high levels of demand or loss of suppliers during market challenges 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 venture interests. 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 or we may use cash on hand. 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 we attempt will be completed on the terms announced, or at all;
- 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, or acquisitions, including integration efforts, would not divert management resources; or
- any dispositions, investments, or acquisitions 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 attract, 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 attract, employ, and retain technical personnel with the ability to design, utilize, and enhance these services and products. 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. We also have numerous small facilities that include sales, project, and support offices and bulk storage facilities throughout the world. All of our owned properties are unencumbered.

The following locations represent our major facilities by segment:

| | |
|---|---|
| *Completion and Production:* | Arbroath, United Kingdom; Johor Bahru, Malaysia; and Lafayette, Louisiana |
| *Drilling and Evaluation:* | Alvarado, Texas; Nisku, Canada; and The Woodlands, Texas |
| *Shared/corporate facilities:* | Carrollton, Texas; Denver, Colorado; Dhahran, Saudi Arabia; Dubai, United Arab Emirates (corporate executive offices); Duncan, Oklahoma; Houston, Texas (corporate executive offices); Kuala Lumpur, Malaysia; London, England; Moscow, Russia; Panama City, Panama; Pune, India; Rio de Janeiro, Brazil; Singapore; and Stavanger, Norway |

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 9 to the consolidated financial statements.

**Item 4. Mine Safety Disclosures.**

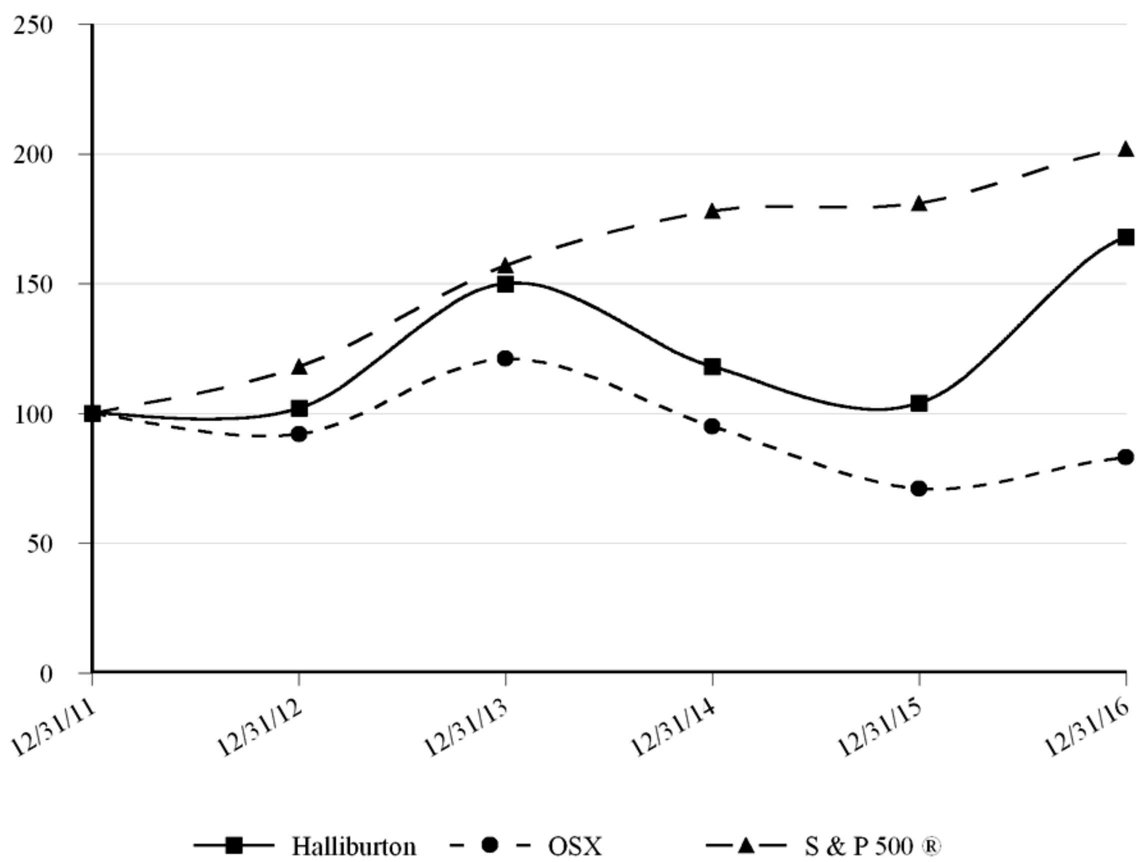
Our barite and bentonite mining operations, in support of our fluid services business, are subject to regulation by the federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required 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 $0.18 per share for all four quarters of 2015 and 2016. 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 continue paying dividends at our current rate during 2017.

The following graph and table compare total shareholder return on our common stock for the five-year period ended December 31, 2016, 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, 2011 and the reinvestment of all dividends. The shareholder return set forth is not necessarily indicative of future performance.




| | December 31 | | | | | |
|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
| Halliburton | $ 100.00 | $ 101.67 | $ 150.46 | $ 117.96 | $ 103.96 | $ 167.97 |
| Philadelphia Oil Service Index (OSX) | 100.00 | 92.26 | 121.15 | 95.32 | 71.30 | 83.08 |
| Standard & Poor's 500 ® Index | 100.00 | 118.45 | 156.82 | 178.28 | 180.75 | 202.37 |

At January 31, 2017, we had 12,992 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, 2016.

| 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 | 21,639 | $46.45 | — | $5,700,004,373 |
| November 1 - 30 | 38,246 | $47.36 | — | $5,700,004,373 |
| December 1 - 31 | 239,807 | $54.00 | — | $5,700,004,373 |
| Total | 299,692 | $52.60 | — | |

(a) All of the 299,692 shares purchased during the three-month period ended December 31, 2016 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 2016, 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 $5.7 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 19 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 14 to the consolidated financial statements on page 66 of this annual report.

**Item 8. Financial Statements and Supplementary Data.**



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

None.

**Item 9(a). Controls and Procedures.**

In accordance with the Securities Exchange Act of 1934 Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 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, 2016 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 41 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

***Termination of Baker Hughes acquisition***

In November 2014, we entered into a merger agreement with Baker Hughes to acquire all outstanding shares of Baker Hughes in a stock and cash transaction. On April 30, 2016, primarily because of the challenges in obtaining remaining regulatory approvals and general industry conditions that severely damaged deal economics, we and Baker Hughes mutually terminated our merger agreement. As a result, we paid Baker Hughes a termination fee of $3.5 billion and recognized the tax-deductible expense during 2016. In addition, we mandatorily redeemed $2.5 billion of senior notes during 2016. See Note 2 to the consolidated financial statements for further information.

***Financial results***

The past several years have continued to be extremely challenging for us, as the impact of reduced commodity prices created widespread pricing pressure and activity reductions on a global basis. 2016 represented the sharpest and deepest industry decline in history. More specifically, the North America market continued to face activity and pricing challenges, with the average United States rig count for the year ended December 31, 2016 having declined nearly 75% from the peak in November 2014. As a result, we recognized significant operating losses in the region during 2016. However, crude prices and the North American rig count have increased significantly since the low points in February 2016 and May 2016, respectively, signaling that we may have hit the bottom of the industry downturn and can begin to look ahead for a market recovery. In the fourth quarter of 2016, the average United States rig count increased 23% compared to the third quarter, and we returned to operating profitability in North America in the fourth quarter after recording operating losses in the first three quarters of the year.

We generated $15.9 billion of revenue during 2016, a 33% decline from the $23.6 billion of revenue generated in 2015. Additionally, we recognized $6.8 billion of operating losses in 2016 compared to $165 million of operating losses in 2015. Our results reflected the negative impact of global activity and pricing reductions, combined with $3.4 billion and $2.2 billion of impairments and other charges recorded in 2016 and 2015, respectively. Additionally, operating results were negatively impacted by Baker Hughes related costs, which were $4.1 billion during 2016 and included a $3.5 billion merger termination fee along with charges resulting from our reversal of assets held for sale accounting, compared to $308 million of Baker Hughes related costs during 2015.

Our operating results towards the latter part of 2016 began to benefit from the impact of the structural global cost savings initiatives we initiated in 2015. We successfully completed our structural cost savings goal of stripping out approximately $1 billion of annualized costs from our business through consolidations of facilities, asset write-offs and headcount reductions. We reduced our global workforce in an effort to address deteriorating market conditions and better align our workforce with anticipated activity levels in the near-term. Personnel expense is one of the largest cost categories for us, and therefore, we implemented cost containment measures as they related to employees and their work locations by reducing our global headcount by approximately 14,000 in 2016 and by approximately 40% since the beginning of 2015.

***Business outlook***

While 2015 and 2016 were challenging as we navigated through this historic industry downturn, we believe our 2016 results reflect successful execution in a difficult environment and position us for the challenges and opportunities ahead. With improvements in commodity prices and the North America rig count from first half 2016 lows, there are signs of optimism in the industry for a market recovery, which we believe we are well positioned to benefit from given our delivery platform and cost containment strategies.

In North America, low commodity prices and rig counts during 2016 resulted in substantial pricing pressure across all of our product service lines. Our customers remain focused on cost and producing more barrels of oil equivalent. We are continuing to collaborate and engineer solutions to maximize asset value for our customers and will continue to take advantage of the recent rig count growth by focusing on increasing equipment utilization, managing costs and expanding our surface efficiency model. Additionally, we gained significant North America market share through the downturn by demonstrating to our customers the benefits of our efficiency and technology, coming out of the downturn with our highest North America market share in history. We have been utilizing this increased market share to drive margin improvement. The historically high level of market share we built in the downturn gives us the ability to focus our work with the most efficient customers and, as such, we continued to execute our strategy of high grading the profitability of our portfolio with customers that value our services. While our market share has been improving, pricing challenges continue as the industry recovers and equipment availability tightens. We will continue to maintain our focus on execution and service quality.

While the North America market appears to have begun to recover, the international downswing continues to persist. The international markets have been more resilient than North America through most of the downturn, particularly in the Eastern Hemisphere, but pricing and activity levels remain under pressure as the industry nears what we believe is the bottom of the international cycle. Low commodity prices have stressed customer budgets and have impacted economics across deepwater and mature field markets, which led to decreased activity and pricing throughout 2016, leading to revenue declines and stressed margins in all three of our international regions. These headwinds still persist, and we do not expect to see an inflection of revenue and margin improvements in the international markets until the latter part of 2017. In the meantime, our international customers remain focused on cash flow, and traditional contracting cycles will likely hinder any substantial rebound coming off the bottom of the cycle. We expect to see a bottoming of the Eastern Hemisphere rig count in the first half of 2017, driven by both cyclical and traditional seasonal impacts, and therefore we expect revenue and margins to continue to be under pressure during 2017 until the market stabilizes. In Latin America, rig activity remains low across the region, while Venezuela continues to experience significant political and economic turmoil. However, we are committed to the Latin America region and believe that oil and gas is a critical element to the region's broader economic recovery. We continue to work with our global customers during this downturn to improve project economics through technology and improved operating efficiency.

We maintained capital discipline during 2016 and adjusted to market conditions, reducing our capital expenditures to $798 million during the year, representing a 63% reduction over 2015. We plan to increase capital spending to approximately $1.0 billion in 2017, which includes reactivating some of our cold stacked pressure pumping equipment and continuing to convert our hydraulic fracturing fleet to Q10 pumps to support our surface efficiency strategy.

As a result of the actions we have taken over the past few years, we believe we are well positioned for the impending market recovery and will scale up our delivery platform by addressing our product service lines one step at a time through a combination of organic growth, investment and selective acquisitions. We plan to continue executing the following strategies in 2017:

- directing capital and resources into strategic growth markets, primarily unconventional plays and mature fields;
- leveraging our broad technology offerings to provide value to our customers and enabling them to more efficiently drill and complete their wells;
- exploring additional 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;
- investing in technology that will help our customers reduce reservoir uncertainty and increase operational efficiency;
- improving working capital and managing our balance sheet to maximize our financial flexibility;
- 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
- collaborating and engineering solutions to maximize asset value for our customers.

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

***Financial markets, liquidity and capital resources***

During 2016, in conjunction with the termination of the Baker Hughes transaction, we paid a $3.5 billion termination fee and mandatorily redeemed $2.5 billion of debt. We also paid off an additional $600 million of senior notes that matured during 2016, closing out the year at $4.0 billion of cash and cash equivalents. This represents a $6.1 billion reduction in our cash position since December 31, 2015. However, we focused on cash flows and generated almost $1 billion of cash during the second half of 2016. This was driven by improved working capital metrics, including a significant reduction of days sales outstanding, disciplined capital spending and tax refunds collected from our carry back of net operating losses we recognized in previous periods.

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. We will continue to execute capital discipline over the next year during this challenged market environment. Given the size of our cash position and the potential impact of U.S. tax reform, we are actively evaluating our options and opportunities around uses of cash, which could include paying off debt, funding acquisitions and organic growth projects or shareholder return opportunities. We also have $3.0 billion available under our revolving credit facility which, with our cash balance, we believe provides us with sufficient liquidity to address the challenges and opportunities of the current market. If determined appropriate, we may seek to raise additional capital in the future through sales of equity or additional indebtedness. For additional information on market conditions, see “Liquidity and Capital Resources” and “Business Environment and Results of Operations.”

## LIQUIDITY AND CAPITAL RESOURCES

As of December 31, 2016, we had $4.0 billion of cash and equivalents, compared to $10.1 billion at December 31, 2015. Additionally, we held $92 million of investments in fixed income securities at December 31, 2016, compared to $96 million at December 31, 2015. These securities are reflected in "Other current assets" and "Other assets" in our consolidated balance sheets. Approximately $1.8 billion of our total cash position as of December 31, 2016 was held by our foreign subsidiaries, a substantial portion of which is available to be repatriated into the United States to fund our U.S. operations or for general corporate purposes, with a portion subject to certain country-specific restrictions. See Note 10 for further discussion on U.S. federal income taxes we recorded during 2016 relating to cumulative undistributed foreign earnings.

***Significant sources and uses of cash in 2016***

*Sources of cash:*

- We improved working capital (receivables, inventories and accounts payable) by a net $1.2 billion during the year, driven by efficient working capital management during the year.
- We received a series of United States tax refunds aggregating $513 million during the second half of 2016, primarily related to the carryback of our net operating losses recognized in 2015. This was partially offset by tax payments for normal business operations in various foreign jurisdictions.

*Uses of cash:*

- Cash flows from operating activities were a negative $1.7 billion in 2016, driven primarily by the $3.5 billion termination fee paid to Baker Hughes during the second quarter.
- Capital expenditures were $798 million in 2016. The capital expenditures in 2016 were predominantly made in our Production Enhancement, Sperry Drilling, Production Solutions, Cementing and Baroid product service lines.
- We mandatorily redeemed $2.5 billion of senior notes in the second quarter and repaid $600 million of senior notes that matured during the third quarter.
- We paid $620 million of dividends to our shareholders in 2016.

***Future sources and uses of cash***

We manufacture most of our own equipment, which allows us flexibility to increase or decrease our capital expenditures based on market conditions. Capital spending for 2017 is currently expected to be approximately $1.0 billion, an increase of over 20% from 2016. The capital expenditures plan for 2017 is primarily directed towards our Production Enhancement, Sperry Drilling, Production Solutions, Wireline and Perforating and Baroid Drilling product service lines. This includes reactivating some of our cold stacked pressure pumping equipment and continuing to convert our hydraulic fracturing fleet to Q10 pumps to support our surface efficiency strategy.

Currently, our quarterly dividend rate is $0.18 per share, or approximately $156 million per quarter. Subject to Board of Directors approval, our intention is to continue paying dividends at our current rate during 2017. Our Board of Directors has authorized a program to repurchase our common stock from time to time. Approximately $5.7 billion remains authorized for repurchases as of December 31, 2016, and may be used for open market and other share purchases. There were no repurchases made under the program during the year ended December 31, 2016.

We expect to receive a United States tax refund in the amount of approximately $475 million during the second half of 2017, primarily related to the carryback of our net operating losses recognized in 2016. Additionally, we had $427 million of gross unrecognized tax benefits at December 31, 2016, of which we estimate $257 million may require a cash payment by us. We estimate that $253 million of the cash payment will not be settled within the next 12 months. We are not able to reasonably estimate in which future periods this amount will ultimately be settled and paid.

During 2014, we reached an agreement, subject to court approval, to settle a substantial portion of the plaintiffs' claims asserted against us relating to the Macondo well incident. During 2016, we made a $33 million payment in accordance with our MDL Settlement. Our total Macondo-related loss contingency liability as of December 31, 2016 was $413 million, of which $369 million is expected to be paid in the first quarter of 2017. In December 2016, we reached an agreement in principle to settle a class action lawsuit and incurred a charge of $54 million. We expect to make the related payment in 2017 when the settlement is finalized and approved by the court. See Note 9 to the consolidated financial statements for further information.

Given the size of our cash position and the potential impact of U.S. tax reform, we are actively evaluating our options and opportunities around uses of cash, which could include paying off debt, funding acquisitions and organic growth projects or shareholder return opportunities.

***Contractual obligations***

The following table summarizes our significant contractual obligations and other long-term liabilities as of December 31, 2016:

| | Payments Due | | | | | | |
|---|---|---|---|---|---|---|---|
| *Millions of dollars* | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
| Long-term debt (a) | $ 163 | $ 841 | $ 1,028 | $ 24 | $ 702 | $ 9,729 | $ 12,487 |
| Interest on debt (b) | 611 | 609 | 584 | 526 | 516 | 8,856 | 11,702 |
| Operating leases | 164 | 135 | 100 | 68 | 52 | 185 | 704 |
| Purchase obligations (c) | 468 | 54 | 34 | 26 | 18 | 39 | 639 |
| Other long-term liabilities (d) | 31 | — | — | — | — | — | 31 |
| Total | $ 1,437 | $ 1,639 | $ 1,746 | $ 644 | $ 1,288 | $ 18,809 | $ 25,563 |

(a) Represents principal amounts of long-term debt, including capital lease obligations and current maturities of debt, which excludes any unamortized debt issuance costs and discounts. See Note 8 to the consolidated financial statements.
(b) Interest on debt includes 80 years of interest on $300 million of debentures at 7.6% interest that become due in 2096.
(c) Amount in 2017 primarily represents certain purchase orders for goods and services utilized in the ordinary course of our business.
(d) Includes 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 2017 as we are currently not able to reasonably estimate our contributions for years after 2017.

***Other factors affecting liquidity***

*Financial position in current market.* As of December 31, 2016, we had $4.0 billion of cash and equivalents, $92 million in fixed income investments and a total of $3.0 billion of available committed bank credit under our revolving credit facility. Furthermore, we have no financial covenants or material adverse change provisions in our bank agreements, and our debt maturities extend over a long period of time. We currently believe that cash on hand, cash flows generated from operations and our available credit facility will provide sufficient liquidity to manage our global cash needs in 2017, including capital expenditures, working capital investments, dividends, if any, and contingent liabilities.

*Guarantee agreements.* In the normal course of business, we have agreements with financial institutions under which approximately $2.0 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2016. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

*Credit ratings.* During 2016, in conjunction with the termination of our merger agreement with Baker Hughes and as a result of general market conditions, Standard & Poor's changed our credit ratings for our long-term debt from A to BBB+ and changed our credit ratings on our short-term debt from A-1 to A-2, with all of our ratings on stable outlook. Moody's Investors Service changed our credit ratings for our long-term debt from A2 to Baa1 and changed our credit ratings on our short-term debt from P-1 to P-2, with all of our ratings on negative outlook.

*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 receivables from our primary customer in Venezuela.

## BUSINESS ENVIRONMENT AND RESULTS OF OPERATIONS

We operate in approximately 70 countries throughout the world to provide a comprehensive range of services and products to the upstream oil and natural gas 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. The industry we serve is highly competitive with many substantial competitors in each segment of our business. In 2016, 2015 and 2014, based on the location of services provided and products sold, 41%, 44% and 51%, respectively, 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, sanctions, expropriation or other governmental actions, inflation, changes in foreign currency exchange rates, 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 within our business segments is 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, global oil supply, the world economy, the availability of credit, government regulation and global stability, which together drive worldwide drilling activity. Due to improved drilling and completion efficiencies as more of our customers move to multi-well pad drilling, our financial performance in North America is impacted by well count in the North America market. Additionally, our financial performance is significantly affected by oil and natural gas prices and worldwide rig activity, which are summarized in the following tables.

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:

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Oil price - WTI (1) | $ 43.14 | $ 48.69 | $ 93.37 |
| Oil price - Brent (1) | 43.55 | 52.36 | 99.04 |
| Natural gas price - Henry Hub (2) | 2.52 | 2.63 | 4.39 |

(1) Oil price measured in dollars per barrel
(2) Natural gas price measured in dollars per million British thermal units (Btu), or MMBtu

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

| **Land vs. Offshore** | 2016 | 2015 | 2014 |
|---|---|---|---|
| United States: | | | |
| Land | 486 | 943 | 1,804 |
| Offshore (incl. Gulf of Mexico) | 23 | 35 | 57 |
| Total | 509 | 978 | 1,861 |
| Canada: | | | |
| Land | 128 | 189 | 378 |
| Offshore | 2 | 2 | 2 |
| Total | 130 | 191 | 380 |
| International (excluding Canada): | | | |
| Land | 734 | 884 | 1,011 |
| Offshore | 221 | 283 | 326 |
| Total | 955 | 1,167 | 1,337 |
| Worldwide total | 1,594 | 2,336 | 3,578 |
| Land total | 1,348 | 2,016 | 3,193 |
| Offshore total | 246 | 320 | 385 |

| **Oil vs. Natural Gas** | 2016 | 2015 | 2014 |
|---|---|---|---|
| United States (incl. Gulf of Mexico): | | | |
| Oil | 409 | 751 | 1,528 |
| Natural gas | 100 | 227 | 333 |
| Total | 509 | 978 | 1,861 |
| Canada: | | | |
| Oil | 63 | 84 | 218 |
| Natural gas | 67 | 107 | 162 |
| Total | 130 | 191 | 380 |
| International (excluding Canada): | | | |
| Oil | 726 | 916 | 1,070 |
| Natural gas | 229 | 251 | 267 |
| Total | 955 | 1,167 | 1,337 |
| Worldwide total | 1,594 | 2,336 | 3,578 |
| Oil total | 1,198 | 1,751 | 2,816 |
| Natural gas total | 396 | 585 | 762 |

| **Drilling Type** | 2016 | 2015 | 2014 |
|---|---|---|---|
| United States (incl. Gulf of Mexico): | | | |
| Horizontal | 400 | 744 | 1,274 |
| Vertical | 60 | 139 | 376 |
| Directional | 49 | 95 | 211 |
| Total | 509 | 978 | 1,861 |

Crude oil prices have been extremely volatile during the past few years. WTI oil spot prices declined significantly towards the second half of 2014 with a peak price of $108 per barrel in June 2014, and continued to decline throughout 2015, ranging from a high of $61 per barrel to a low of $35 per barrel. WTI oil spot prices declined further into February 2016 to a low of $26 per barrel, a level which had not been experienced since 2003. Brent crude oil spot prices declined from a high of $115 per barrel in June 2014, and continued to decline throughout 2015, ranging from a high of $66 per barrel to a low of $35 per barrel, and declined further to $26 per barrel in January 2016. Commodity prices have increased from the low point experienced in early 2016 to highs of $54 per barrel in December 2016 for WTI and $55 per barrel in December 2016 for Brent.

While prices continue to fluctuate, we believe this price improvement signals the turning point in the North American market and believe that the international market should begin to improve in the latter half of 2017.

WTI and Brent crude oil spot prices had a monthly average in December 2016 of $52 per barrel and $53 per barrel, respectively. The market reactions to the OPEC plan to cut production by 1.2 million barrels per day beginning in January 2017, as well as growing domestic and global consumption, have contributed to rising oil prices. However, prices are expected to remain relatively unchanged for the beginning of 2017 as significant economic and geopolitical events are expected to affect market participants' expectations and demand growth and as global oil inventory builds at a slower rate. Crude oil production in the United States is projected to average 9.0 million barrels per day in 2017, largely due to increases in offshore Gulf of Mexico production and rising tight oil production.

In the United States Energy Information Administration (EIA) January 2017 "Short Term Energy Outlook," the EIA projects that Brent prices will average $53 per barrel in 2017, while WTI prices will average about $1 less per barrel. The EIA also notes that price projections are highly uncertain due to the current values of futures and options contracts. The International Energy Agency's (IEA) January 2017 "Oil Market Report" forecasts the 2017 global demand to average approximately 97.8 million barrels per day, which is up 1% from 2016, driven by an increase in the Asia Pacific region, while all other regions remain approximately the same.

The average full year 2016 Henry Hub natural gas price in the United States decreased approximately 4% from 2015. However, the Henry Hub natural gas spot price averaged $3.59 per MMBtu in December 2016, an increase of $0.60 per MMBtu, or 20%, from September 2016. Production decline, increased demand for natural gas to fuel electricity generation and inventories falling below the five-year average contributed to the highest natural gas prices since December 2014. The EIA January 2017 “Short Term Energy Outlook” projects Henry Hub natural gas prices to average $3.55 per MMBtu in 2017. The EIA also expects natural gas consumption to increase in 2017, primarily because of higher residential and commercial consumption based on a forecast of colder winter temperatures and, to a lesser extent, due to new fertilizer and chemical projects in the industrial sector.

***North America operations***

The average North America oil-directed rig count declined 363 rigs, or 43%, for the full year 2016 as compared to 2015, while the average North America natural gas-directed rig count decreased 167 rigs, or 50%, during the same period. In the United States land market during 2016, there was a decline of 48% in the average rig count compared to 2015.

The United States average rig count for December 2016 reflected a drop of 67% since its peak in November 2014. Price erosion for our services continued during the majority of 2016. However, the rig count has begun to show improvement with a 23% increase in the average fourth quarter United States rig count when compared to the third quarter, and is expected to continue improving in the first half of 2017. As a result of the recent uptick in activity and the structural changes to our delivery platform we made during this down cycle, we returned to operating profitability in North America in the fourth quarter of 2016 after recording operating losses in the first three quarters of the year. We anticipate our North America revenue for the first quarter of 2017 will perform in-line with changes in the rig count. In the long run, we believe the continuing shifts to unconventional oil and liquids-rich basins in the United States land market will continue to drive increased service intensity and will create higher demand in fluid chemistry and other technologies required for these complex reservoirs, which will have positive implications for our operations as the energy market recovers.

In the Gulf of Mexico, the average offshore rig count for 2016 was down 34% compared to 2015. Low commodity prices have stressed budgets and have impacted economics across the deepwater market, which has led to decreased activity and pricing throughout 2016. These headwinds still persist today. We believe there will continue to be challenges in 2017 on deepwater project economics. Additionally, activity in the Gulf of Mexico is dependent on, among the factors described above, governmental approvals for permits, our customers' actions, and the entry and exit of deepwater rigs in the market.

***International operations***

The average international rig count for 2016 decreased by 18% compared to 2015, as the international markets remain stressed as they near the bottom of the cycle. Depressed crude oil prices have caused many of our customers to reduce their budgets and defer several new projects; however, we have continued to work with our customers to improve project economics through technology and improved operating efficiency. In Latin America, the rig count hit a 15-year low across the region during 2016, and Venezuela continues to experience significant political and economic turmoil. While our fourth quarter results in the region were solid, headwinds persist in the larger Latin American markets and until these are alleviated, we do not believe we will see improvement. However, we are committed to the region and believe that oil and gas is a critical element to the region’s broader economic recovery. For our Eastern Hemisphere business, we expect to see an inflection in the rig count in the latter half of 2017, supported by strengthening activity in the land-based mature field markets but decreased activity in the deepwater markets.

*Venezuela.* In February 2015, the Venezuelan government created a three-tier foreign exchange rate system, which included the National Center of Foreign Commerce official rate of 6.3 Bolívares per United States dollar, the SICAD and the SIMADI. During the first quarter of 2015, we began utilizing the SIMADI floating rate mechanism to remeasure our net monetary assets denominated in Bolívares, with an initial market rate of 192 Bolívares per United States dollar, resulting in a foreign currency loss of $199 million recorded during the first quarter of 2015.

In February 2016, the Venezuelan government revised the three-tier exchange rate system to a new dual-rate system designed to streamline access to dollars for production and essential imports as well as to combat inflation. The dual-rate exchange mechanisms are as follows: (i) the DIPRO, which replaced and devalued the official rate from 6.3 to 10.0 Bolívares per United States dollar, and represents a protected rate made available for vital imports such as food, medicine and raw materials for production; and (ii) the DICOM, which replaces the SIMADI and which is intended to be a free floating system that will fluctuate according to market supply and demand. The DICOM had a market rate of 674 Bolívares per United States dollar at December 31, 2016. We are utilizing the DICOM to remeasure our net monetary assets denominated in Bolívares, and the revised system and continued devaluation did not materially affect our financial statements for the year ended December 31, 2016.

As of December 31, 2016, our total net investment in Venezuela was approximately $820 million, with only $1 million of net monetary liabilities denominated in Bolívares, and we had an additional $38 million of surety bond guarantees outstanding relating to our Venezuelan operations.

We have continued to experience delays in collecting payments 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. During the second quarter of 2016, we executed a financing agreement with our primary customer in Venezuela in an effort to actively manage these customer receivables, resulting in an exchange of $200 million of outstanding trade receivables for an interest-bearing promissory note. We recorded the note at its fair market value at the date of exchange, which resulted in a $148 million pre-tax loss on exchange in the second quarter. This instrument provides a more defined schedule around the timing of payments, while we generate a return awaiting payment. We are using an effective interest method to accrete the carrying amount to its par value as it matures. We received interest payments on this promissory note during the third and fourth quarters, and the carrying amount of the note was $70 million as of December 31, 2016. In the fourth quarter of 2016, we agreed to exchange this promissory note for a new note with the same maturity and coupon, but which is expected to be tradeable in a more liquid market. We intend to hold the new note to maturity.

Our total outstanding net trade receivables in Venezuela were $610 million as of December 31, 2016, excluding the $200 million promissory note receivable discussed above, compared to $704 million as of December 31, 2015, which represents 15% and 14% of total company trade receivables at the respective balance sheet dates. The majority of our Venezuela receivables are United States dollar-denominated receivables. Of the $610 million receivables in Venezuela as of December 31, 2016, $409 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets. As a result of current conditions in Venezuela and the continued delays in collecting payments on our receivables in the country, we began curtailing activity in Venezuela during the first quarter of 2016.

For additional information, see Part I, Item 1(a), “Risk Factors.”

## RESULTS OF OPERATIONS IN 2016 COMPARED TO 2015

| ***REVENUE:*** *Millions of dollars* | 2016 | 2015 | Favorable (Unfavorable) | Percentage Change |
|---|---|---|---|---|
| Completion and Production | $ 8,882 | $ 13,682 | $ (4,800) | (35)% |
| Drilling and Evaluation | 7,005 | 9,951 | (2,946) | (30) |
| Total revenue | $ 15,887 | $ 23,633 | $ (7,746) | (33)% |
| *By geographic region:* | | | | |
| North America | $ 6,770 | $ 10,856 | $ (4,086) | (38)% |
| Latin America | 1,860 | 3,149 | (1,289) | (41) |
| Europe/Africa/CIS | 2,993 | 4,175 | (1,182) | (28) |
| Middle East/Asia | 4,264 | 5,453 | (1,189) | (22) |
| Total | $ 15,887 | $ 23,633 | $ (7,746) | (33)% |

| ***OPERATING INCOME:*** *Millions of dollars* | 2016 | 2015 | Favorable (Unfavorable) | Percentage Change |
|---|---|---|---|---|
| Completion and Production | $ 107 | $ 1,069 | $ (962) | (90)% |
| Drilling and Evaluation | 794 | 1,519 | (725) | (48) |
| Total | 901 | 2,588 | (1,687) | (65) |
| Corporate and other | (4,322) | (576) | (3,746) | 650 |
| Impairments and other charges | (3,357) | (2,177) | (1,180) | 54 |
| Total operating loss | $ (6,778) | $ (165) | $ (6,613) | 4,008 % |
| *By geographic region:* | | | | |
| North America | $ (201) | $ 458 | $ (659) | (144)% |
| Latin America | 111 | 440 | (329) | (75) |
| Europe/Africa/CIS | 269 | 523 | (254) | (49) |
| Middle East/Asia | 722 | 1,167 | (445) | (38) |
| Total | $ 901 | $ 2,588 | $ (1,687) | (65)% |

Consolidated revenue in 2016 decreased 33% compared to 2015, associated with widespread pricing pressure and activity reductions on a global basis, primarily attributable to stimulation activity, well completion services and pricing declines in North America. Revenue outside of North America was 57% of consolidated revenue in 2016 and 54% of consolidated revenue in 2015.

We reported a consolidated operating loss of $6.8 billion in 2016, as compared to an operating loss of $165 million in 2015. Operating results were negatively impacted by $3.4 billion and $2.2 billion of impairments and other charges recorded during 2016 and 2015, respectively. Additionally, we incurred $4.1 billion of Baker Hughes related costs during 2016, primarily due to the $3.5 billion termination fee and $464 million of charges resulting from our reversal of assets held for sale accounting, compared to $308 million of Baker Hughes related costs during 2015. Also impacting consolidated operating results was a significant decline in stimulation activity and pricing declines in North America and reduced well completion services across all regions as a result of the global downturn in the energy market. See Note 2 to the consolidated financial statements for further discussion of the Baker Hughes transaction and financial statement impact of terminating our merger agreement and Note 3 to the consolidated financial statements for further information about impairments and other charges.

***OPERATING SEGMENTS***

*Completion and Production*

Completion and Production (C&P) revenue was $8.9 billion in 2016, a decrease of $4.8 billion, or 35%, compared to 2015, due to a decline in activity and pricing in the majority of our product services lines, particularly North America pressure pumping services which drove the majority of the C&P revenue decline. International revenue declined as a result of reductions in well completion services and stimulation activity in all regions.

C&P operating income was $107 million in 2016, compared to $1.1 billion of operating income in 2015, with decreased profitability across all regions as a result of global activity and pricing reductions, primarily in North America stimulation activity and completion of well services across all regions.

*Drilling and Evaluation*

Drilling and Evaluation (D&E) revenue was $7.0 billion in 2016, a decrease of $2.9 billion, or 30%, from 2015. Reductions were seen across all product service lines due to the low rig count, lower pricing and customer budget constraints worldwide.

D&E operating income was $794 million in 2016, a decrease of $725 million, or 48%, compared to 2015, driven by a decline in activity and pricing across all regions, particularly drilling and logging activity in Middle East/Asia region and reduced fluid services in Latin America.

***GEOGRAPHIC REGIONS***

*North America*

North America revenue was $6.8 billion in 2016, a 38% decline compared to 2015, relative to a 45% decline in average North America rig count. We had an operating loss of $201 million in 2016, compared to $458 million of operating income in 2015. These declines were driven by reduced activity and pricing pressure throughout the United States land market, specifically relating to stimulation and drilling activity.

*Latin America*

Latin America revenue was $1.9 billion in 2016, a 41% reduction compared to 2015, with operating income of $111 million in 2016, a 75% decline from 2015. These reductions were primarily related to our decision to curtail activity in Venezuela and currency weakness in the country, reduced activity across all product service lines in Mexico and lower drilling activity in Brazil and Colombia.

*Europe/Africa/CIS*

Europe/Africa/CIS revenue was $3.0 billion in 2016, a decline of 28% compared to 2015, with operating income of $269 million in 2016, a 49% decrease compared to 2015. These decreases were driven by a reduction of activity in the North Sea, Angola, Nigeria and Congo, along with lower drilling activity, completion tools sales and pressure pumping services throughout the region.

*Middle East/Asia*

Middle East/Asia revenue was $4.3 billion in 2016, a reduction of 22% compared 2015, with operating income of $722 million in 2016, a 38% decrease from 2015. This was the result of pricing concessions across the region, along with reduced activity for pressure pumping services in the Middle East, Indonesia and Australia, and a decline in drilling and logging activity in Indonesia, Malaysia and the Middle East.

***OTHER OPERATING ITEMS***

*Corporate and other* expenses were $4.3 billion in 2016, as compared to $576 million in 2015, primarily driven by Baker Hughes related costs. During 2016, we incurred a $3.5 billion termination fee and $464 million of charges resulting from our reversal of assets held for sale accounting, as compared to $308 million of Baker Hughes related costs during 2015. See Note 2 to the consolidated financial statements for further discussion of the Baker Hughes transaction and the financial statement impact of terminating our merger agreement.

*Impairments and other charges.* Primarily as a result of the downturn in the energy market and its corresponding impact on the company's business outlook, we recorded a total of approximately $3.4 billion in company-wide charges during 2016, which consisted of fixed asset impairments and write-offs, inventory write-downs, impairments of intangible assets, severance costs, country and facility closures, a loss on exchange for a promissory note from our primary customer in Venezuela and other charges. This compares to $2.2 billion of impairments and other charges recorded in 2015 which consisted of fixed asset impairments and write-offs, inventory write-downs, impairments of intangible assets, severance costs, country and facility closures and other charges. See Note 3 to the consolidated financial statements for further information.

***NONOPERATING ITEMS***

*Interest expense, net* increased $192 million in 2016, as compared to 2015. This was primarily due to additional interest resulting from the $7.5 billion of senior notes issued in November 2015, coupled with $41 million of redemption fees and associated costs, which were recorded through interest expense, related to the $2.5 billion of senior notes mandatorily redeemed during the second quarter of 2016. Additionally, we recognized $25 million of interest income in 2016 related to interest receipts and accretion on the promissory note from our primary customer in Venezuela, as we continue to accrete the carrying amount of the promissory note to its par value as it matures. See Note 14 to the consolidated financial statements for further information on our promissory note in Venezuela.

*Other, net* was a $208 million loss in 2016, as compared to a $324 million loss in 2015, driven by foreign currency exchange losses in various countries primarily due to the strengthening U.S. dollar. These losses included a $53 million loss in 2016 for the devaluation of the Egyptian pound and a $199 million loss in 2015 as a result of utilizing the new currency exchange mechanism in Venezuela. Also impacting both periods were foreign currency exchange losses in Brazil and Argentina. See "Business Environment and Results of Operations" for further information regarding Venezuela.

*Effective tax rate*. During 2016, we recorded a total income tax benefit of $1.9 billion on pre-tax losses of $7.6 billion, resulting in an effective tax rate of 24.4%. During 2015, we recorded a total income tax benefit $274 million on pre-tax losses of $936 million, resulting in an effective tax rate of 29.3%. See Note 10 to the consolidated financial statements for significant drivers of these effective tax rates.

## RESULTS OF OPERATIONS IN 2015 COMPARED TO 2014

| ***REVENUE:*** *Millions of dollars* | 2015 | 2014 | Favorable (Unfavorable) | Percentage Change |
|---|---|---|---|---|
| Completion and Production | $ 13,682 | $ 20,253 | $ (6,571) | (32)% |
| Drilling and Evaluation | 9,951 | 12,617 | (2,666) | (21) |
| Total revenue | $ 23,633 | $ 32,870 | $ (9,237) | (28)% |
| *By geographic region:* | | | | |
| North America | $ 10,856 | $ 17,698 | $ (6,842) | (39)% |
| Latin America | 3,149 | 3,875 | (726) | (19) |
| Europe/Africa/CIS | 4,175 | 5,490 | (1,315) | (24) |
| Middle East/Asia | 5,453 | 5,807 | (354) | (6) |
| Total | $ 23,633 | $ 32,870 | $ (9,237) | (28)% |

| ***OPERATING INCOME:*** *Millions of dollars* | 2015 | 2014 | Favorable (Unfavorable) | Percentage Change |
|---|---|---|---|---|
| Completion and Production | $ 1,069 | $ 3,670 | $ (2,601) | (71)% |
| Drilling and Evaluation | 1,519 | 1,740 | (221) | (13) |
| Total | 2,588 | 5,410 | (2,822) | (52) |
| Corporate and other | (576) | (184) | (392) | 213 |
| Impairments and other charges | (2,177) | (129) | (2,048) | 1,588 |
| Total operating income (loss) | $ (165) | $ 5,097 | $ (5,262) | (103)% |
| *By geographic region:* | | | | |
| North America | $ 458 | $ 3,216 | $ (2,758) | (86)% |
| Latin America | 440 | 431 | 9 | 2 |
| Europe/Africa/CIS | 523 | 689 | (166) | (24) |
| Middle East/Asia | 1,167 | 1,074 | 93 | 9 |
| Total | $ 2,588 | $ 5,410 | $ (2,822) | (52)% |

Consolidated revenue in 2015 decreased 28% compared to 2014, associated with widespread pricing pressure and activity reductions on a global basis, primarily attributable to pressure pumping in North America and Europe/Africa/CIS. Revenue outside of North America was 54% of consolidated revenue in 2015 and 46% of consolidated revenue in 2014.

We reported a consolidated operating loss of $165 million in 2015, as compared to operating income of $5.1 billion in 2014. This $5.3 billion decrease was primarily driven by a significant decline in pressure pumping activity and pricing declines in North America as a result of the global downturn in the energy market. Also impacting consolidated operating income was $2.2 billion of impairments and other charges recorded in 2015 and $308 million of Baker Hughes related costs. See Note 3 to the consolidated financial statements for further information about impairments and other charges.

## *OPERATING SEGMENTS*

*Completion and Production*

Completion and Production (C&P) revenue declined $6.6 billion in 2015, or 32%, compared to 2014, due to activity decreases across all regions, mainly North America pressure pumping services which drove the majority of the C&P revenue decline. International revenue fell as a result of reductions in well completion services and pressure pumping activity across all regions.

C&P operating income was $1.1 billion in 2015, a decrease of $2.6 billion, or 71% compared to 2014, driven predominantly by the decline in North America pressure pumping services and decreased profitability across all regions as a result of global activity and pricing reductions.

*Drilling and Evaluation*

Drilling and Evaluation (D&E) revenue decreased $2.7 billion in 2015, or 21%, compared to 2014, primarily due to reduced drilling and logging activity in all regions due to the low rig count, lower pricing and customer budget constraints worldwide. Revenue declines were partially offset by increased project management services throughout Middle East/Asia.

D&E operating income was $1.5 billion in 2015, a decrease of 13% compared to 2014, partly due to decreased drilling and logging activity primarily in North America, partially offset by increased project management services and fluid activity in Middle East/Asia.

## *GEOGRAPHIC REGIONS*

*North America*

North America revenue was $10.9 billion in 2015, a 39% decline compared to 2014, relative to a 48% decline in average North America rig count. Operating income was $458 million in 2015, a substantial reduction from the $3.2 billion of operating income reported in 2014. These reductions were driven by a decline in activity across a majority of product service lines, predominately in the United States land market as a result of steep rig count declines, pricing concessions and reduced stimulation activity.

*Latin America*

Latin America revenue was $3.1 billion in 2015, a 19% reduction compared to 2014, with operating income of $440 million in 2015, a 2% increase from 2014. These results were impacted by reduced activity and pricing in Mexico, primarily associated with pressure pumping and production solution services, along with reduced offshore activity in Brazil. Operating income benefited from depreciation cessation related to assets held for sale during 2015 along with improved pipeline and fluid services in Venezuela and well completions activity in Brazil.

*Europe/Africa/CIS*

Europe/Africa/CIS revenue was $4.2 billion in 2015, a decline of 24% compared to 2014, with operating income of $523 million in 2015, a 24% decrease compared to 2014. These decreases were driven by reduced fluid services and currency weakness in Norway, lower pressure pumping services and currency weakness in Russia and decreased drilling and fluid activity throughout the entire region.

*Middle East/Asia*

Middle East/Asia revenue was $5.5 billion in 2015, a reduction of 6% compared to 2014, with operating income of $1.2 billion in 2015, a 9% increase from 2014. These results were impacted by decreased pressure pumping activity in Australia and reduced drilling activity across the region. Operating income benefited from depreciation cessation related to assets held for sale during 2015 along with increased project management and fluid services activity in the Middle East.

## *OTHER OPERATING ITEMS*

*Corporate and other* expenses increased to $576 million in 2015 compared to $184 million in 2014, primarily due to $308 million of Baker Hughes related costs recorded in 2015, as compared to $17 million in 2014. Additionally, in 2014, we recorded a reduction of our Macondo-related loss contingency liability and an expected insurance recovery totaling $195 million.

*Impairments and other charges.* As a result of the downturn in the energy market and its corresponding impact on our business outlook, we recorded a total of approximately $2.2 billion in company-wide charges during 2015, which consisted of fixed asset impairments, inventory write-downs, impairments of intangible assets, severance costs, country and facility closures and other charges. During 2014, $129 million was recorded for impairments and other charges. See Note 3 to the consolidated financial statements for further information.

***NONOPERATING ITEMS***

*Interest expense, net* increased $64 million in 2015, compared to 2014, primarily due to fees associated with the bridge facility commitment related to the Baker Hughes transaction and additional interest expense associated with the $7.5 billion of senior notes issued in November 2015. See Note 8 to the consolidated financial statements for further information.

*Other, net* was a $324 million loss in 2015, as compared to a $2 million loss in 2014, primarily due to a $199 million foreign exchange loss we incurred in Venezuela in the first quarter of 2015 as a result of utilizing the new currency exchange mechanism, coupled with foreign currency exchange losses in Brazil and Argentina. See Note 3 to the consolidated financial statements and "Business Environment and Results of Operations" for further information about Venezuela.

*Effective tax rate.* Our effective tax rate was 29.3% for 2015 and 27.1% for 2014. The effective tax rates in both periods were positively impacted by lower tax rates in certain foreign jurisdictions. The effective tax rate for 2015 was also impacted by the tax effects of the $2.2 billion of impairments and other charges, a change in mix of geographic earnings in which we experienced low levels of United States income during the year, additional valuation allowances booked on foreign deferred tax assets, a $199 million foreign currency exchange loss in Venezuela and non-deductible Baker Hughes related costs. The effective tax rate for 2014 was positively impacted by a $201 million net operating loss valuation allowance released as a result of a reorganization of our legal entity structure in Brazil. See Note 10 to the consolidated financial statements for further information regarding income taxes.

## 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.

***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 70 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 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 9 of our consolidated financial statements, as of December 31, 2016, 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. 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. See Note 3 for further discussion on the significant impairment charges we recorded on our long-lived assets during the years ended December 31, 2016, 2015 and 2014 as a result of the downturn in the energy market.

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 assessment.

The quantitative impairment test we perform for goodwill utilizes certain assumptions, including forecasted revenue and costs assumptions. If the crude oil market remains at low levels for a sustained period of time, we could record an impairment of the carrying value of our goodwill in the future. If crude oil prices decline further or remain at low levels, to the extent appropriate we expect to perform our goodwill impairment assessment on a more frequent basis to determine whether an impairment is required.

***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 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. These assumptions differ based on varying factors specific to each particular country or economic environment.

The discount rate utilized in 2016 to determine the projected benefit obligation at the measurement date for our United Kingdom pension plan, which constituted 84% of our international plans' pension obligations, was 2.55%, compared to a discount rate of 3.90% utilized in 2015. The expected long-term rate of return assumption used for our United Kingdom pension plan expense was 5.4% in 2016 and 6.0% in 2015.

The following table illustrates the sensitivity to changes in certain assumptions, holding all other assumptions constant, for our United Kingdom pension plan.

| | Increase (Decrease) on | |
|---|---|---|
| *Millions of dollars* | Pretax Pension Expense in 2016 | Pension Benefit Obligation at December 31, 2016 |
| 50-basis-point decrease in discount rate | $ 2 | $ 104 |
| 50-basis-point increase in discount rate | (2) | (96) |
| 50-basis-point decrease in expected long-term rate of return | 4 | NA |
| 50-basis-point increase in expected long-term rate of return | (4) | NA |

Our international defined benefit plans reduced pretax income by $30 million in 2016, $42 million in 2015 and $36 million in 2014. Included in these amounts was income from expected return on plan assets of $40 million in 2016, $48 million in 2015 and $52 million in 2014. Actual returns on international plan assets totaled $132 million in 2016, compared to $34 million in 2015. Our net actuarial loss, net of tax, related to international pension plans was $290 million at December 31, 2016 and $205 million at December 31, 2015. 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 five to 16 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 30 years, which represents the estimated average remaining lifetime of the benefit obligations. These ranges reflect varying maturity levels among the plans.

During 2016, we made contributions of $19 million to our international defined benefit plans. We expect to make contributions of approximately $15 million to our international defined benefit plans in 2017.

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 15 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 4.3%. At December 31, 2016, allowance for bad debts totaled $175 million, or 4.3% of notes and accounts receivable before the allowance. At December 31, 2015, allowance for bad debts totaled $145 million, or 2.7% 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, 2016 would have resulted in a $41 million adjustment to 2016 total operating costs and expenses. See Note 5 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 Part I, 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, 2016, we had no material off balance sheet arrangements, except for operating leases. In the normal course of business, we have agreements with financial institutions under which approximately $2.0 billion of letters of credit, bank guarantees or surety bonds were outstanding as of December 31, 2016. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization. None of these off balance sheet arrangements either has, or is likely to have, a material effect on our consolidated financial statements. For information on our contractual obligations related to operating leases, see Note 9 to the consolidated financial statements and "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, 2016 would result in a $47 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 $15 million of interest charges for the year ended December 31, 2016.

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 14 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 9 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," "believe," "do not believe," "plan," "estimate," "intend," "expect," "do not expect," "anticipate," "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, 2016 based upon criteria set forth in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2016, our internal control over financial reporting is effective.

The effectiveness of Halliburton's internal control over financial reporting as of December 31, 2016 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<br>Chairman of the Board and<br>Chief Executive Officer | Mark A. McCollum<br>Executive Vice President and<br>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, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016. 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, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, 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, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 7, 2017 expressed an unqualified opinion on the effectiveness of Halliburton Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 7, 2017

## 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, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Halliburton Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Halliburton Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated February 7, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 7, 2017

**HALLIBURTON COMPANY**
**Consolidated Statements of Operations**

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of dollars and shares except per share data* | 2016 | 2015 | 2014 |
| **Revenue:** | | | |
| Services | $ 11,140 | $ 16,981 | $ 24,535 |
| Product sales | 4,747 | 6,652 | 8,335 |
| Total revenue | 15,887 | 23,633 | 32,870 |
| **Operating costs and expenses:** | | | |
| Cost of services | 11,253 | 16,014 | 20,855 |
| Cost of sales | 3,770 | 5,099 | 6,479 |
| Baker Hughes related costs and termination fee | 4,057 | 308 | 17 |
| Impairments and other charges | 3,357 | 2,177 | 129 |
| General and administrative | 228 | 200 | 293 |
| Total operating costs and expenses | 22,665 | 23,798 | 27,773 |
| **Operating income (loss)** | (6,778) | (165) | 5,097 |
| Interest expense, net of interest income of $59, $16, and $13 | (639) | (447) | (383) |
| Other, net | (208) | (324) | (2) |
| **Income (loss) from continuing operations before income taxes** | (7,625) | (936) | 4,712 |
| Income tax benefit (provision) | 1,858 | 274 | (1,275) |
| **Income (loss) from continuing operations** | (5,767) | (662) | 3,437 |
| Income (loss) from discontinued operations, net | (2) | (5) | 64 |
| **Net income (loss)** | $ (5,769) | $ (667) | $ 3,501 |
| Net (income) loss attributable to noncontrolling interest | 6 | (4) | (1) |
| **Net income (loss) attributable to company** | $ (5,763) | $ (671) | $ 3,500 |
| **Amounts attributable to company shareholders:** | | | |
| Income (loss) from continuing operations | $ (5,761) | $ (666) | $ 3,436 |
| Income (loss) from discontinued operations, net | (2) | (5) | 64 |
| **Net income (loss) attributable to company** | $ (5,763) | $ (671) | $ 3,500 |
| **Basic income per share attributable to company shareholders:** | | | |
| Income (loss) from continuing operations | $ (6.69) | $ (0.78) | $ 4.05 |
| Income (loss) from discontinued operations, net | — | (0.01) | 0.08 |
| **Net income (loss) per share** | $ (6.69) | $ (0.79) | $ 4.13 |
| **Diluted income per share attributable to company shareholders:** | | | |
| Income (loss) from continuing operations | $ (6.69) | $ (0.78) | $ 4.03 |
| Income (loss) from discontinued operations, net | — | (0.01) | 0.08 |
| **Net income (loss) per share** | $ (6.69) | $ (0.79) | $ 4.11 |
| Basic weighted average common shares outstanding | 861 | 853 | 848 |
| Diluted weighted average common shares outstanding | 861 | 853 | 852 |

See notes to consolidated financial statements.

**HALLIBURTON COMPANY**
**Consolidated Statements of Comprehensive Income**

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of dollars* | 2016 | 2015 | 2014 |
| **Net income (loss)** | $ (5,769) | $ (667) | $ 3,501 |
| **Other comprehensive income, net of income taxes:** | | | |
| Defined benefit and other post retirement plans adjustment | (92) | 105 | (84) |
| Unrealized loss on cash flow hedges | — | (67) | — |
| Other | 1 | (2) | (7) |
| Other comprehensive income (loss), net of income taxes | (91) | 36 | (91) |
| **Comprehensive income (loss)** | $ (5,860) | $ (631) | $ 3,410 |
| Comprehensive (income) loss attributable to noncontrolling interest | 6 | (4) | (1) |
| **Comprehensive income (loss) attributable to company shareholders** | $ (5,854) | $ (635) | $ 3,409 |

See notes to consolidated financial statements.

**HALLIBURTON COMPANY**
**Consolidated Balance Sheets**

| *Millions of dollars and shares except per share data* | December 31 2016 | 2015 |
|---|---|---|
| **Assets** | | |
| **Current assets:** | | |
| Cash and equivalents | $ 4,009 | $ 10,077 |
| Receivables (net of allowances for bad debts of $175 and $145) | 3,922 | 5,317 |
| Inventories | 2,275 | 2,993 |
| Prepaid income taxes | 585 | 527 |
| Other current assets | 886 | 1,156 |
| **Total current assets** | 11,677 | 20,070 |
| Property, plant and equipment (net of accumulated depreciation of $11,198 and $11,576) | 8,532 | 12,117 |
| Goodwill | 2,414 | 2,385 |
| Deferred income taxes | 1,960 | 552 |
| Other assets | 2,417 | 1,818 |
| **Total assets** | $ 27,000 | $ 36,942 |
| **Liabilities and Shareholders' Equity** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 1,764 | $ 2,019 |
| Accrued employee compensation and benefits | 544 | 862 |
| Liabilities for Macondo well incident | 369 | 400 |
| Deferred revenue | 261 | 298 |
| Taxes other than income | 218 | 293 |
| Current maturities of long-term debt | 163 | 659 |
| Other current liabilities | 704 | 806 |
| **Total current liabilities** | 4,023 | 5,337 |
| Long-term debt | 12,214 | 14,687 |
| Employee compensation and benefits | 574 | 479 |
| Other liabilities | 741 | 944 |
| **Total liabilities** | 17,552 | 21,447 |
| **Shareholders' equity:** | | |
| Common shares, par value $2.50 per share (authorized 2,000 shares, issued 1,070 and 1,071 shares) | 2,674 | 2,677 |
| Paid-in capital in excess of par value | 201 | 274 |
| Accumulated other comprehensive loss | (454) | (363) |
| Retained earnings | 14,141 | 20,524 |
| Treasury stock, at cost (204 and 215 shares) | (7,153) | (7,650) |
| **Company shareholders' equity** | 9,409 | 15,462 |
| Noncontrolling interest in consolidated subsidiaries | 39 | 33 |
| **Total shareholders' equity** | 9,448 | 15,495 |
| **Total liabilities and shareholders' equity** | $ 27,000 | $ 36,942 |

See notes to consolidated financial statements.

## HALLIBURTON COMPANY
## Consolidated Statements of Cash Flows

| *Millions of dollars* | Year Ended December 31 2016 | 2015 | 2014 |
|---|---|---|---|
| **Cash flows from operating activities:** | | | |
| Net income (loss) | $ (5,769) | $ (667) | $ 3,501 |
| Adjustments to reconcile net income (loss) to cash flows from operating activities: | | | |
| Impairments and other charges | 3,357 | 2,177 | 129 |
| Depreciation, depletion and amortization | 1,503 | 1,835 | 2,126 |
| Deferred income tax benefit, continuing operations | (1,501) | (224) | (454) |
| Cash impact of impairments and other charges - severance payments | (273) | (304) | (28) |
| Payment related to the Macondo well incident | (33) | (333) | (569) |
| Changes in assets and liabilities: | | | |
| Receivables | 899 | 1,468 | (1,381) |
| Inventories | 552 | 153 | (271) |
| Accounts payable | (219) | (603) | 489 |
| Other | (219) | (596) | 520 |
| **Total cash flows provided by (used in) operating activities** | (1,703) | 2,906 | 4,062 |
| **Cash flows from investing activities:** | | | |
| Capital expenditures | (798) | (2,184) | (3,283) |
| Proceeds from sales of property, plant and equipment | 222 | 168 | 338 |
| Payments to acquire businesses, net of cash acquired | (31) | (39) | (231) |
| Other investing activities | (103) | (137) | 38 |
| **Total cash flows used in investing activities** | (710) | (2,192) | (3,138) |
| **Cash flows from financing activities:** | | | |
| Payments on long-term borrowings | (3,171) | (8) | (4) |
| Dividends to shareholders | (620) | (614) | (533) |
| Proceeds from issuance of common stock | 186 | 167 | 332 |
| Proceeds from issuance of long-term debt, net | 74 | 7,440 | — |
| Payments to reacquire common stock | — | — | (800) |
| Other financing activities | (9) | 96 | (25) |
| **Total cash flows provided by (used in) financing activities** | (3,540) | 7,081 | (1,030) |
| Effect of exchange rate changes on cash | (115) | (9) | 41 |
| Increase (decrease) in cash and equivalents | (6,068) | 7,786 | (65) |
| Cash and equivalents at beginning of year | 10,077 | 2,291 | 2,356 |
| **Cash and equivalents at end of year** | $ 4,009 | $ 10,077 | $ 2,291 |
| **Supplemental disclosure of cash flow information:** | | | |
| Cash payments (receipts) during the period for: | | | |
| Interest | $ 659 | $ 380 | $ 384 |
| Income taxes | $ (20) | $ 370 | $ 1,269 |

See notes to consolidated financial statements.

# HALLIBURTON COMPANY
## Consolidated Statements of Shareholders' Equity

| *Millions of dollars* | Common Shares | Paid-in Capital in Excess of Par Value | Treasury Stock | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling interest in Consolidated Subsidiaries | Total |
|---|---|---|---|---|---|---|---|
| | Company Shareholders' Equity | | | | | | |
| **Balance at December 31, 2013** | $ 2,680 | $ 415 | $ (8,049) | $ 18,842 | $ (307) | $ 34 | $ 13,615 |
| **Comprehensive income (loss):** | | | | | | | |
| Net income | — | — | — | 3,500 | — | 1 | 3,501 |
| Other comprehensive loss | — | — | — | — | (92) | — | (92) |
| Common shares repurchased | — | — | (800) | — | — | — | (800) |
| Stock plans | (1) | (161) | 718 | — | — | — | 556 |
| Cash dividends ($0.63 per share) | — | — | — | (533) | — | — | (533) |
| Other | — | 55 | — | — | — | (4) | 51 |
| **Balance at December 31, 2014** | $ 2,679 | $ 309 | $ (8,131) | $ 21,809 | $ (399) | $ 31 | $ 16,298 |
| **Comprehensive income (loss):** | | | | | | | |
| Net income (loss) | — | — | — | (671) | — | 4 | (667) |
| Other comprehensive income | — | — | — | — | 36 | — | 36 |
| Stock plans | (2) | (39) | 481 | — | — | — | 440 |
| Cash dividends ($0.72 per share) | — | — | — | (614) | — | — | (614) |
| Other | — | 4 | — | — | — | (2) | 2 |
| **Balance at December 31, 2015** | $ 2,677 | $ 274 | $ (7,650) | $ 20,524 | $ (363) | $ 33 | $ 15,495 |
| **Comprehensive income (loss):** | | | | | | | |
| Net loss | — | — | — | (5,763) | — | (6) | (5,769) |
| Other comprehensive loss | — | — | — | — | (91) | — | (91) |
| Stock plans | (3) | (69) | 497 | — | — | — | 425 |
| Cash dividends ($0.72 per share) | — | — | — | (620) | — | — | (620) |
| Other | — | (4) | — | — | — | 12 | 8 |
| **Balance at December 31, 2016** | $ 2,674 | $ 201 | $ (7,153) | $ 14,141 | $ (454) | $ 39 | $ 9,448 |

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 a leading provider of services and products to 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. 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.

***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 do not have a controlling interest, but over which we do exercise 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 addition, certain reclassifications of prior period balances have been made to conform to the current period presentation.

***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.

*New Accounting Pronouncement.* In May 2014, a new revenue recognition standard was issued that will supersede existing revenue recognition guidance. See Note 16 for additional information.

***Research and development***

Research and development costs are expensed as incurred. Research and development costs were $329 million in 2016, $487 million in 2015 and $601 million in 2014.

***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, 2014: | $ 1,606 | $ 724 | $ 2,330 |
| Current year acquisitions | 27 | 26 | 53 |
| Purchase price adjustments for previous acquisitions | 1 | 1 | 2 |
| Balance at December 31, 2015: | $ 1,634 | $ 751 | $ 2,385 |
| Current year acquisitions | 31 | — | 31 |
| Purchase price adjustments for previous acquisitions | (2) | — | (2) |
| Other | 16 | (16) | — |
| Balance at December 31, 2016: | $ 1,679 | $ 735 | $ 2,414 |

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 exist such as significant current or projected operating losses. In 2016, 2015 and 2014 we performed a quantitative impairment test. This two-step quantitative process compares 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 is performed to measure the amount of impairment loss to be recorded, if any.

In performing our quantitative impairment tests, we estimated the fair value for each reporting unit using a discounted cash flow analysis based on management's short-term and long-term forecast of operating performance. Our discounted cash flow analysis for each reporting unit includes significant assumptions regarding discount rates, revenue growth rates, expected profitability margins, forecasted capital expenditures, the timing of an anticipated market recovery and the timing of expected future cash flows. As such, these analyses incorporate inherent uncertainties that are difficult to predict in volatile economic environments and could result in impairment charges in future periods if actual results materially differ from the estimated assumptions utilized in our forecasts. As a result of our annual goodwill impairment assessments performed in 2016, 2015 and 2014, we determined that the fair value of each reporting unit exceeded its net book value and, therefore, no goodwill impairments were deemed necessary.

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 two to fifteen 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.

Taxes are provided as necessary with respect to foreign earnings that are not permanently reinvested. During 2016, we concluded that we no longer intend to permanently reinvest a portion of our cumulative undistributed foreign earnings outside of the United States and recorded corresponding U.S. federal income tax expenses. See Note 10 for further information. We have not provided income taxes on a portion of our cumulative 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.

***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. Revenue and expense transactions are translated at the average rates in effect during the year, except for those expenses associated with nonmonetary balance sheet accounts, which are translated at historical rates. Gains or losses from remeasurement of monetary assets and liabilities due to 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 12 and Note 16 for additional information related to stock-based compensation.

**Note 2. Acquisitions and Dispositions**

***Termination of Baker Hughes acquisition***

In November 2014, we entered into a merger agreement with Baker Hughes to acquire all outstanding shares of Baker Hughes in a stock and cash transaction. On April 30, 2016, we and Baker Hughes mutually terminated our merger agreement primarily because of the challenges in obtaining remaining regulatory approvals and general industry conditions that severely damaged deal economics.

In April 2015, we had announced our decision to market for sale our Fixed Cutter and Roller Cone Drill Bits, our Directional Drilling, and our Logging-While-Drilling/Measurement-While-Drilling businesses in connection with the anticipated Baker Hughes transaction. Accordingly, beginning in April 2015, the assets and liabilities for these businesses, which are included within our Drilling and Evaluation operating segment, were classified as held for sale and the corresponding depreciation and amortization expense ceased at that time. Since our proposed divestitures no longer met the assets held for sale accounting criteria at March 31, 2016, we reclassified these businesses to assets held and used in the consolidated balance sheets for both periods presented. We recorded corresponding charges during 2016 totaling $464 million within "Baker Hughes related costs and termination fee" in our consolidated statements of operations, which included $329 million of accumulated unrecognized depreciation and amortization expense for these businesses during the period the associated assets were classified as held for sale, along with $135 million of capitalized and other divestiture-related costs. Beginning April 1, 2016, all depreciation and amortization expense associated with these businesses were included in operating costs and expenses on our consolidated statements of operations.

The reclassification of assets held for sale to assets held and used resulted in the following changes from amounts previously reported on our consolidated balance sheets as of December 31, 2015: $2.1 billion decrease in "Assets held for sale;" $576 million increase in "Inventories;" $1.2 billion increase in "Property, plant and equipment;" $276 million increase in "Goodwill;" $57 million increase in "Other assets;" $24 million increase in "Accrued employee compensation and benefits;" $46 million decrease in "Other current liabilities;" and $22 million increase in "Employee compensation and benefits."

In conjunction with the termination of our merger agreement, we paid Baker Hughes a termination fee of $3.5 billion in May 2016 and recognized this expense during the second quarter. The termination also triggered a mandatory redemption of $2.5 billion of the senior notes we had issued in November 2015 in contemplation of the transaction. We redeemed those notes in May 2016 using cash on hand at a price of 101% of their principal amount, plus accrued and unpaid interest. The notes redeemed included the $1.25 billion of 2.7% senior notes due in 2020 and $1.25 billion of 3.375% senior notes due in 2022. The redemption resulted in $41 million of fees and associated expenses included in interest expense on our consolidated statements of operations for the year ended December 31, 2016.

**Note 3. Impairments and Other Charges**

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 we conduct impairment tests on goodwill annually. We review the recoverability of the carrying value of our 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. Additionally, inventories are valued at the lower of cost or market.

Market conditions have negatively impacted our business during 2016 with continued depressed commodity prices and widespread pricing pressure and activity reductions for our products and services on a global basis. As a result of these conditions and their corresponding impact on our business outlook, we determined the carrying amount of a number of our long-lived assets exceeded their respective fair values due to projected declines in asset utilization. We assessed the fair value of our long-lived assets based on a discounted cash flow analysis, which required the use of significant unobservable inputs such as management's short-term and long-term forecast of operating performance, including revenue growth rates and expected profitability margins, and a discount rate based on our weighted average cost of capital.

Over the last four years, we have been systematically converting our pressure pumping fleet in North America over to a new pump and blender design. As such, we impaired or wrote off a large portion of our older equipment, primarily during the first quarter of 2016. Additionally, market conditions during 2016 required us to take other actions to reduce some of our infrastructure and further reduce our global workforce in an effort to mitigate the impact of the industry downturn and better align our workforce with anticipated activity levels in the near-term. This resulted in a headcount reduction of approximately 14,000 for the year ended December 31, 2016 and corresponding severance charges recognized during the period. We also determined that the cost of some of our inventory exceeded its market value, resulting in associated write-downs of its carrying value during the year ended December 31, 2016.

We executed a financing agreement with our primary customer in Venezuela during the second quarter of 2016 in an effort to actively manage outstanding receivables in the country, resulting in an exchange of $200 million of outstanding trade receivables for an interest-bearing promissory note. We recorded the note at its fair market value at the date of exchange based on available pricing data points for similar assets in an illiquid market, which resulted in a $148 million pre-tax loss on exchange during the second quarter. For additional information, see Note 14 and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations."

As a result of the events described above, we recorded impairments and other charges of approximately $3.4 billion, $2.2 billion and $129 million during the years ended December 31, 2016, 2015 and 2014, respectively. Total impairments and other charges consisted of fixed asset impairments and write-offs, severance costs, impairments of intangible assets, inventory write-downs, country and facility closures, a loss on exchange for the Venezuela promissory note and other items.

The following table presents various charges we recorded during the years ended December 31, 2016, 2015 and 2014 as a result of the downturn in the energy industry and other matters, all of which were recorded within "Impairments and other charges" on our consolidated statements of operations:

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of dollars* | 2016 | 2015 | 2014 |
| **Industry downturn:** | | | |
| Fixed asset impairments | $ 2,550 | $ 760 | $ 47 |
| Severance costs | 315 | 352 | 28 |
| Inventory write-downs | 166 | 484 | 24 |
| Intangible asset impairments | 88 | 212 | 10 |
| Other | 67 | 201 | 20 |
| **Other matters:** | | | |
| Venezuela promissory note loss | 148 | — | — |
| Country closures | 39 | 80 | — |
| Other | (16) | 88 | — |
| Total impairments and other charges | $ 3,357 | $ 2,177 | $ 129 |

**Note 4. 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. For more information about the product service lines included in each segment, see Part I, Item 1, "Business." 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. Intersegment revenue and revenue between geographic areas are immaterial. Our equity in earnings and losses of unconsolidated affiliates that are accounted for using the equity method of accounting are included within cost of services on our statements of operations, which is part of operating income of the applicable segment.

The following tables present financial information on our business segments.

***Operations by business segment***

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of dollars* | 2016 | 2015 | 2014 |
| **Revenue:** | | | |
| Completion and Production | $ 8,882 | $ 13,682 | $ 20,253 |
| Drilling and Evaluation | 7,005 | 9,951 | 12,617 |
| Total revenue | $ 15,887 | $ 23,633 | $ 32,870 |
| **Operating income (loss):** | | | |
| Completion and Production | $ 107 | $ 1,069 | $ 3,670 |
| Drilling and Evaluation | 794 | 1,519 | 1,740 |
| Total operations | 901 | 2,588 | 5,410 |
| Corporate and other (a) | (4,322) | (576) | (184) |
| Impairments and other charges (b) | (3,357) | (2,177) | (129) |
| Total operating income (loss) | $ (6,778) | $ (165) | $ 5,097 |
| Interest expense, net of interest income (c) | $ (639) | $ (447) | $ (383) |
| Other, net | (208) | (324) | (2) |
| Income (loss) from continuing operations before income taxes | $ (7,625) | $ (936) | $ 4,712 |
| **Capital expenditures:** | | | |
| Completion and Production | $ 500 | $ 1,526 | $ 1,953 |
| Drilling and Evaluation | 297 | 650 | 1,297 |
| Corporate and other | 1 | 8 | 33 |
| Total | $ 798 | $ 2,184 | $ 3,283 |
| **Depreciation, depletion and amortization:** | | | |
| Completion and Production | $ 900 | $ 1,160 | $ 1,162 |
| Drilling and Evaluation | 569 | 638 | 934 |
| Corporate and other | 34 | 37 | 30 |
| Total | $ 1,503 | $ 1,835 | $ 2,126 |

(a) Includes Baker Hughes related costs for the periods presented, including a $3.5 billion termination fee and an aggregate $464 million of charges for the reversal of assets held for sale accounting during the year ended December 31, 2016.

(b) Impairments and other charges are as follows:

- For the year ended December 31, 2016, includes $2.1 billion attributable to Completion and Production, $1.2 billion attributable to Drilling and Evaluation and $10 million attributable to Corporate and other.
- For the year ended December 31, 2015, includes $1.1 billion attributable to Completion and Production, $1.0 billion attributable to Drilling and Evaluation and $88 million attributable to Corporate and other.
- For the year ended December 31, 2014, includes $60 million attributable to Completion and Production and $69 million attributable to Drilling and Evaluation.

(c) For the year ended December 31, 2016, includes $41 million of debt redemption fees and associated expenses related to the $2.5 billion of debt mandatorily redeemed and additional interest resulting from the senior notes issued in late 2015.

| Millions of dollars | December 31 2016 | 2015 |
|---|---|---|
| **Total assets:** | | |
| Completion and Production | $ 10,349 | $ 13,628 |
| Drilling and Evaluation | 8,473 | 10,531 |
| Shared assets | 3,371 | 1,785 |
| Corporate and other | 4,807 | 10,998 |
| Total | $ 27,000 | $ 36,942 |

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.

The following tables present information by geographic area. In 2016, 2015 and 2014, based on the location of services provided and products sold, 41%, 44% and 51% of our consolidated revenue was from the United States. As of December 31, 2016 and December 31, 2015, 50% and 48% of our property, plant and equipment was located in the United States. No other country accounted for more than 10% of our revenue or property, plant and equipment during the periods presented.

***Operations by geographic region***

| Millions of dollars | Year Ended December 31 2016 | 2015 | 2014 |
|---|---|---|---|
| **Revenue:** | | | |
| North America | $ 6,770 | $ 10,856 | $ 17,698 |
| Latin America | 1,860 | 3,149 | 3,875 |
| Europe/Africa/CIS | 2,993 | 4,175 | 5,490 |
| Middle East/Asia | 4,264 | 5,453 | 5,807 |
| Total | $ 15,887 | $ 23,633 | $ 32,870 |

| Millions of dollars | December 31 2016 | 2015 |
|---|---|---|
| **Net property, plant and equipment:** | | |
| North America | $ 4,431 | $ 6,091 |
| Latin America | 1,068 | 1,463 |
| Europe/Africa/CIS | 1,253 | 1,620 |
| Middle East/Asia | 1,780 | 2,943 |
| Total | $ 8,532 | $ 12,117 |

**Note 5. Receivables**

As of December 31, 2016, 28% of our gross trade receivables were from customers in the United States and 15% were from customers in Venezuela. As of December 31, 2015, 26% of our gross trade receivables were from customers in the United States and 14% were from customers in Venezuela. Other than the United States and Venezuela, no other country or single customer accounted for more than 10% of our gross trade receivables at these dates.

*Venezuela.* We have continued to experience delays in collecting payments 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. During the second quarter of 2016, we executed a financing agreement with our primary customer in Venezuela in an effort to actively manage these customer receivables, resulting in an exchange of $200 million of outstanding trade receivables for an interest-bearing promissory note.

Our total outstanding net trade receivables in Venezuela were $610 million as of December 31, 2016, excluding the promissory note receivable discussed above, compared to $704 million as of December 31, 2015, which represents 15% and 14% of total company trade receivables for the respective periods. The majority of our Venezuela receivables are United States dollar-denominated receivables. Of the $610 million receivables in Venezuela as of December 31, 2016, $409 million has been classified as long-term and included within "Other assets" on our consolidated balance sheets.

As a result of market conditions in Venezuela and the continued delays in collecting payments on our receivables in the country, we began curtailing activity in Venezuela during the first quarter of 2016. See Note 14 and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations" for additional information about the promissory note exchange.

The following table presents a rollforward of our allowance for bad debts for 2014, 2015 and 2016.

| *Millions of dollars* | Balance at Beginning of Period | Charged to Costs and Expenses | Write-Offs | Balance at End of Period |
|---|---|---|---|---|
| Year ended December 31, 2014 | $ 117 | $ 26 | $ (6) | $ 137 |
| Year ended December 31, 2015 | 137 | 44 | (36) | 145 |
| Year ended December 31, 2016 | 145 | 50 | (20) | 175 |

**Note 6. 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 $133 million at December 31, 2016 and $138 million at December 31, 2015. If the average cost method had been used, total inventories would have been $16 million higher than reported at December 31, 2016 and $18 million higher than reported at December 31, 2015. The cost of the remaining inventory was recorded on the average cost method. Inventories consisted of the following:

| | December 31 | |
|---|---|---|
| *Millions of dollars* | 2016 | 2015 |
| Finished products and parts | $ 1,388 | $ 1,992 |
| Raw materials and supplies | 778 | 879 |
| Work in process | 109 | 122 |
| Total | $ 2,275 | $ 2,993 |

All amounts in the table above are reported net of obsolescence reserves of $263 million at December 31, 2016 and $251 million at December 31, 2015.

**Note 7. Property, Plant and Equipment**

Property, plant and equipment were composed of the following:

| | December 31 | |
|---|---|---|
| *Millions of dollars* | 2016 | 2015 |
| Land | $ 228 | $ 240 |
| Buildings and property improvements | 3,399 | 3,486 |
| Machinery, equipment and other | 16,103 | 19,967 |
| Total | 19,730 | 23,693 |
| Less accumulated depreciation | 11,198 | 11,576 |
| Net property, plant and equipment | $ 8,532 | $ 12,117 |

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

| | Buildings and Property Improvements | |
|---|---|---|
| | 2016 | 2015 |
| 1 - 10 years | 11% | 12% |
| 11 - 20 years | 42% | 41% |
| 21 - 30 years | 22% | 22% |
| 31 - 40 years | 25% | 25% |

| | Machinery, Equipment and Other | |
|---|---|---|
| | 2016 | 2015 |
| 1 - 5 years | 34% | 23% |
| 6 - 10 years | 57% | 69% |
| 11 - 20 years | 9% | 8% |

**Note 8. Debt**

Our long-term debt, including current maturities, consisted of the following:

| | December 31 | |
|---|---|---|
| *Millions of dollars* | 2016 | 2015 |
| 5.0% senior notes due November 2045 | $ 2,000 | $ 2,000 |
| 3.8% senior notes due November 2025 | 2,000 | 2,000 |
| 3.5% senior notes due August 2023 | 1,100 | 1,100 |
| 4.85% senior notes due November 2035 | 1,000 | 1,000 |
| 6.15% senior notes due September 2019 | 1,000 | 1,000 |
| 7.45% senior notes due September 2039 | 1,000 | 1,000 |
| 4.75% senior notes due August 2043 | 900 | 900 |
| 6.7% senior notes due September 2038 | 800 | 800 |
| 3.25% senior notes due November 2021 | 500 | 500 |
| 4.5% senior notes due November 2041 | 500 | 500 |
| 2.0% senior notes due August 2018 | 400 | 400 |
| 5.9% senior notes due September 2018 | 400 | 400 |
| 7.6% senior debentures due August 2096 | 300 | 300 |
| 8.75% senior debentures due February 2021 | 185 | 185 |
| 6.75% notes due February 2027 | 104 | 104 |
| 7.53% notes due May 2017 | 45 | 45 |
| 3.375% senior notes due November 2022 | — | 1,250 |
| 2.7% senior notes due November 2020 | — | 1,250 |
| 1.0% senior notes due August 2016 | — | 600 |
| Other | 253 | 144 |
| Unamortized debt issuance costs and discounts | (110) | (132) |
| Total | 12,377 | 15,346 |
| Current maturities | (163) | (659) |
| Total long-term debt | $ 12,214 | $ 14,687 |

***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.

In conjunction with the termination of our merger agreement with Baker Hughes, we mandatorily redeemed $2.5 billion of the senior notes we had issued in November 2015 in contemplation of the transaction. We redeemed those notes in May 2016 using cash on hand at a price of 101% of their principal amount, plus accrued and unpaid interest. The notes redeemed included the $1.25 billion of 2.7% senior notes due in 2020 and $1.25 billion of 3.375% senior notes due in 2022. We also repaid $600 million of senior notes that matured in August 2016.

***Revolving credit facilities***

In July 2015, we entered into a new five-year revolving credit agreement with a capacity of $3.0 billion. The credit agreement is for working capital or general corporate purposes and expires on July 21, 2020. The full amount of the revolving credit facility was available as of December 31, 2016.

***Debt maturities***

Our long-term debt matures as follows: $163 million in 2017, $841 million in 2018, $1.0 billion in 2019, $24 million in 2020, $702 million in 2021 and the remainder in 2022 and thereafter.

**Note 9. Commitments and Contingencies**

***Macondo well incident***

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 an affiliate of Transocean Ltd. and had been drilling the Macondo exploration well in the Gulf of Mexico for the lease operator, BP Exploration & Production, Inc. (BP). We performed a variety of services on that well for BP. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

*Litigation and settlements.* Numerous lawsuits relating to the Macondo well incident and alleging damages arising from the blowout were filed against various parties, including BP, Transocean and us, in federal and state courts throughout the United States, most of which were consolidated in a Multi District Litigation proceeding (MDL) in the United States Eastern District of Louisiana. The defendants in the MDL proceeding filed a variety of cross claims against each other.

In 2012, BP reached a settlement to resolve the substantial majority of eligible private economic loss and medical claims stemming from the Macondo well incident (BP MDL Settlements). The MDL court has since certified the classes and granted final approval for the BP MDL Settlements, which also provided for the release by participating plaintiffs of compensatory damage claims against us.

The trial for the first phase of the MDL proceeding occurred in February 2013 through April 2013 and covered issues arising out of the conduct and degree of culpability of various parties. In September 2014, the MDL court ruled (Phase One Ruling) that, among other things, (1) in relation to the Macondo well incident, BP's conduct was reckless, Transocean's conduct was negligent, and our conduct was negligent, (2) fault for the Macondo well incident was apportioned 67% to BP, 30% to Transocean and 3% to us, and (3) the indemnity and release clauses in our contract with BP are valid and enforceable against BP. The MDL court did not find that our conduct was grossly negligent, thereby eliminating our exposure in the MDL for punitive damages.

In September 2014, prior to the Phase One Ruling, we reached an agreement, subject to court approval, to settle a substantial portion of the plaintiffs' claims asserted against us relating to the Macondo well incident (our MDL Settlement). Pursuant to our MDL Settlement, we agreed to pay an aggregate of $1.1 billion, which includes legal fees and costs, into a settlement fund in three installments over two years, except that one installment of legal fees will not be paid until all of the conditions to the settlement have been satisfied or waived. Certain conditions must be satisfied before our MDL Settlement becomes effective and the funds are released from the settlement fund. These conditions include, among others, the issuance of a final order of the MDL court, including the resolution of certain appeals. In addition, we have the right to terminate our MDL Settlement if more than an agreed number of plaintiffs elect to opt out of the settlement prior to the expiration of the opt out deadline to be established by the MDL court. Before approving our MDL Settlement, the MDL court must certify the settlement class, the numerous class members must be notified of the proposed settlement, and the court must hold a fairness hearing. The Court has issued preliminary approval of our MDL Settlement, and the hearing for the final approval was held on November 10, 2016. We are unable to predict when our MDL Settlement will receive final approval.

Our MDL Settlement does not cover claims against us by the state governments of Alabama, Florida, Mississippi, Louisiana, or Texas, claims by our own employees, compensatory damages claims by plaintiffs in the MDL that opted out of or were excluded from the settlement class in the BP MDL Settlements, or claims by other defendants in the MDL or their respective employees. However, these claims have either been dismissed, are subject to dismissal, are subject to indemnification by BP, or are not believed to be material.

On May 20, 2015, we and BP entered into an agreement to resolve all remaining claims against each other, and pursuant to which BP will defend and indemnify us in future trials for compensatory damages. On July 2, 2015, BP announced that it had reached agreements in principle to settle all remaining federal, state and local government claims arising from the Macondo well incident. We have also entered into an agreement with Transocean to dismiss all claims made against each other.

*Regulatory action.* 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. We have appealed the INCs, but the appeal has been suspended pending certain proceedings in the MDL and potential appeals. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal has ended. 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.

*Loss contingency.* During 2016, we made a legal fees payment of $33 million in accordance with our MDL Settlement and we reduced our non-current Macondo liability by $28 million. Accordingly, as of December 31, 2016, our remaining loss contingency liability related to the Macondo well incident was $413 million, consisting of a current portion of $369 million related to our MDL Settlement and a non-current portion of $44 million unrelated to that settlement. Our loss contingency liability has not been reduced for potential recoveries from our insurers. See below for information regarding amounts that we could potentially recover from insurance.

Subject to the satisfaction of the conditions of our MDL Settlement, we believe that the BP MDL Settlement, our MDL Settlement, the Phase One Ruling and our settlement with BP have eliminated any additional material financial exposure to us in relation to the Macondo well incident.

*Insurance coverage.* We had a general liability insurance program of $600 million at the time of the Macondo well incident. Our insurance was 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. Through December 31, 2016, we have incurred approximately $1.5 billion of expenses related to the MDL Settlement, legal fees, and other settlement-related costs, of which $409 million has been reimbursed or is expected to be reimbursed under our insurance program. Some of the insurance carriers that issued policies covering the final layer of insurance coverage relating to the Macondo well incident notified us that they would not reimburse us with respect to our MDL Settlement; however, we have settled with several of them and those settlement recoveries are included in the $409 million discussed above. We have initiated arbitration proceedings to pursue recovery of the remaining balance of approximately $100 million. Due to the uncertainty surrounding such recovery, no related amounts have been recognized in the consolidated financial statements as of December 31, 2016.

***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. and our disclosures and reserves relating to our 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, 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 issued an order in November 2008 denying the motion for class certification. The Fifth Circuit Court of Appeals affirmed the district court's order denying class certification. In June 2011, the United States Supreme Court reversed the Fifth Circuit ruling and the case was returned to the lower courts for further consideration.

In January 2012, the district court issued an order certifying the class. In April 2013, the Fifth Circuit affirmed the district court's order. In June 2014, the Supreme Court reversed the Fifth Circuit and held that we are entitled to rebut that presumption of class member reliance by presenting evidence that there was no impact on our stock price from the alleged misrepresentations. The Supreme Court vacated the Fifth Circuit's decision and remanded for further proceedings consistent with the Supreme Court decision.

In July 2015, the district court denied certification for the plaintiff class with respect to five of the six dates upon which the plaintiff claimed that disclosures correcting previously misleading statements had been made that resulted in an impact to the stock price. However, the district court certified the class with respect to a disclosure made on December 7, 2001 regarding an adverse jury verdict in an asbestos case that plaintiffs alleged was corrective. We appealed the ruling to the Fifth Circuit. The Fifth Circuit heard oral argument on the appeal in August 2016 and its consideration of the appeal is suspended pending finalization of the settlement discussed below. In October 2016, the district court issued an order continuing the December 2016 trial date.

In December 2016, we reached an agreement in principle to settle this lawsuit, without any admission of liability and subject to approval by the district court. We will fund approximately $54 million of the $100 million settlement fund, and our insurer will fund the balance. As such, we recorded a $54 million charge on our consolidated statement of operations for the year ended December 31, 2016. Plaintiff's counsel fees and costs will be awarded from the settlement fund. The settlement remains subject to final documentation and the approval of the district court following notice to class members.

***Investigations***

We have conducted 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 Foreign Corrupt Practices Act (FCPA) and other applicable laws. We have engaged outside counsel and independent forensic accountants to assist us with these investigations.

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 to satisfy local content requirements. The e-mail also alleged conflicts of interest, self-dealing, and the failure to act on alleged violations of our COBC and the FCPA. We contacted the Department of Justice (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 produced documents to them both voluntarily and as a result of SEC subpoenas to us and certain of our current and former officers and employees.

Our counsel has engaged in discussions with the SEC staff concerning a potential resolution of the investigations. Any potential resolution will be subject not only to an agreement with the SEC staff on specific terms and specific language in the settlement documentation, but also to approval of the Commissioners of the SEC and agreement with the DOJ. Accordingly, there can be no assurance that the discussions with the SEC will result in a final resolution of the investigations or, if a resolution is achieved, the timing of such resolution. In the event a resolution is not agreed to and approved, we cannot predict the ultimate outcome of the investigations 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. Our accrued liabilities for environmental matters were $50 million as of December 31, 2016 and December 31, 2015. 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.

Additionally, we have subsidiaries that have been named as potentially responsible parties along with other third parties for eight federal and state Superfund sites for which we have established reserves. As of December 31, 2016, those eight sites accounted for approximately $5 million of our $50 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 $2.0 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2016. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization. None of these off balance sheet arrangements either has, or is likely to have, a material effect on our consolidated financial statements.

***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 $587 million in 2016, $875 million in 2015, and $1.0 billion in 2014.

Future total rentals on our noncancellable operating leases are $704 million in the aggregate, which includes the following: $164 million in 2017; $135 million in 2018; $100 million in 2019; $68 million in 2020; $52 million in 2021; and $185 million thereafter.

**Note 10. Income Taxes**

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

| *Millions of dollars* | Year Ended December 31 2016 | 2015 | 2014 |
|---|---|---|---|
| Current income taxes: | | | |
| Federal | $ 737 | $ 635 | $ (959) |
| Foreign | (415) | (636) | (734) |
| State | 35 | 51 | (36) |
| Total current | 357 | 50 | (1,729) |
| Deferred income taxes: | | | |
| Federal | 1,343 | (18) | 83 |
| Foreign | 77 | 262 | 357 |
| State | 81 | (20) | 14 |
| Total deferred | 1,501 | 224 | 454 |
| Income tax benefit (provision) | $ 1,858 | $ 274 | $ (1,275) |

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

| *Millions of dollars* | Year Ended December 31 2016 | 2015 | 2014 |
|---|---|---|---|
| United States | $ (6,636) | $ (1,560) | $ 3,020 |
| Foreign | (989) | 624 | 1,692 |
| Total | $ (7,625) | $ (936) | $ 4,712 |

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

| | Year Ended December 31 2016 | 2015 | 2014 |
|---|---|---|---|
| United States statutory rate | 35.0% | 35.0% | 35.0% |
| Undistributed foreign earnings | (5.1) | — | — |
| Impact of foreign income taxed at different rates (a) | (3.2) | 17.0 | (5.7) |
| Valuation allowance against tax assets | (2.1) | (8.3) | (3.6) |
| Domestic manufacturing deduction | (1.3) | — | (1.9) |
| State income taxes | 1.0 | 2.0 | 0.8 |
| Non-deductible acquisition costs | 0.6 | (4.5) | — |
| Adjustments of prior year taxes | 0.2 | 1.3 | 0.3 |
| Venezuela devaluation | — | (7.5) | — |
| Other items, net | (0.7) | (5.7) | 2.2 |
| Total effective tax rate on continuing operations | 24.4% | 29.3% | 27.1% |

(a) For the year ended December 31, 2015, we recognized taxable losses in our United States operations, partially offset by taxable income in our foreign operations in which the corresponding tax expenses are applied at lower statutory rates in certain jurisdictions, which had a significant effect on our effective tax rate during the year.

Our effective tax rate on continuing operations was 24.4% for 2016, 29.3% for 2015 and 27.1% for 2014. For the year ended December 31, 2016, we had the following significant items impacting our effective tax rate:

- we recognized taxable losses in our United States operations in which we recorded tax benefits at the U.S. statutory rate and taxable losses in our foreign operations in which the corresponding tax benefits are applied at lower statutory rates in certain jurisdictions;
- we recorded $393 million of deferred tax expenses during the year on approximately $3.4 billion of cumulative undistributed foreign earnings. See further discussion below;
- we established valuation allowances on certain deferred tax assets aggregating $163 million as a result of market conditions and their corresponding impact on our business outlook;
- we recorded $96 million of tax expenses associated with our inability to utilize certain domestic manufacturing deductions as a result of the carryback of net operating losses to prior tax periods; and
- we recorded tax benefits on the $3.4 billion of impairments and other charges recorded during the year, some of which are taxed at lower income tax rates in certain foreign jurisdictions.

During 2016, as a result of the payment of the Baker Hughes termination fee and the general market conditions, we reviewed the financial requirements of our United States companies and our foreign subsidiaries, together with the overall capital structure of the global organization. As a result of this review, we concluded that we no longer intend to permanently reinvest a portion of our cumulative undistributed foreign earnings outside of the United States and recorded corresponding United States federal income tax expenses. We have not provided United States income taxes and foreign withholding taxes on the remaining undistributed earnings of foreign subsidiaries as of December 31, 2016 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, 2016, the cumulative amount of earnings upon which United States income taxes have not been provided is approximately $4.0 billion. It is not practicable to estimate the additional 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* | 2016 | 2015 |
| Gross deferred tax assets: | | |
| Net operating loss carryforwards | $ 1,647 | $ 540 |
| Foreign tax credit carryforwards | 648 | 365 |
| Employee compensation and benefits | 352 | 403 |
| Accrued liabilities | 325 | 392 |
| Other | 536 | 359 |
| Total gross deferred tax assets | 3,508 | 2,059 |
| Gross deferred tax liabilities: | | |
| Depreciation and amortization | 585 | 1,334 |
| Undistributed foreign earnings | 406 | 5 |
| Other | 145 | 109 |
| Total gross deferred tax liabilities | 1,136 | 1,448 |
| Valuation allowances | 453 | 213 |
| Net deferred income tax asset | $ 1,919 | $ 398 |

At December 31, 2016, we had $1.6 billion of domestic and foreign tax-effected net operating loss carryforwards. The ultimate realization of these deferred tax assets depends on the ability to generate sufficient taxable income in the appropriate taxing jurisdiction. $174 million of the net operating loss carryforwards will expire after taxable years ended from 2017 through 2021, $142 million will expire after taxable years ended from 2022 through 2026, and $77 million will expire after taxable years ended from 2027 through 2036. In addition, $943 million of United States net operating loss carryforwards will expire after the 2036 taxable year. The remaining balance will not expire. Additionally, we had $758 million of foreign tax credit carryforwards that will expire from 2022 through 2026, which are offset by foreign branch deferred activity reflected in the above table, along with $84 million of research and development tax credit carryforwards that will expire from 2027 through 2036.

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, 2014 | $ 175 | | $ 34 |
| Change in prior year tax positions | 83 | | 24 |
| Change in current year tax positions | 84 | | — |
| Cash settlements with taxing authorities | (27) | | (1) |
| Lapse of statute of limitations | (1) | | (1) |
| Balance at December 31, 2014 | $ 314 | | $ 56 |
| Change in prior year tax positions | (33) | | 7 |
| Change in current year tax positions | 62 | | 1 |
| Cash settlements with taxing authorities | (16) | | (15) |
| Lapse of statute of limitations | (5) | | (2) |
| Balance at December 31, 2015 | $ 322 | (a) | $ 47 |
| Change in prior year tax positions | 44 | | 20 |
| Change in current year tax positions | 129 | | 3 |
| Cash settlements with taxing authorities | (62) | | (8) |
| Lapse of statute of limitations | (6) | | (1) |
| Balance at December 31, 2016 | $ 427 | (a)(b) | $ 61 |

(a) Includes $84 million as of December 31, 2016 and $67 million as of December 31, 2015 in foreign unrecognized tax benefits that would give rise to a United States tax credit. Approximately $257 million, which excludes $5 million of unrecognized tax benefits covered by an indemnification asset, as of December 31, 2016 and $176 million, which excludes $10 million of unrecognized tax benefits covered by an indemnification asset, as of December 31, 2015, 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 $15 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 2009. 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 years 2012 through 2015 are under review by the Internal Revenue Service, and we are awaiting final review by the Joint Committee on Taxation of the appeals resolution for the tax years 2010 through 2011.

**Note 11. Shareholders' Equity**

***Shares of common stock***

The following table summarizes total shares of common stock outstanding:

| | December 31 | |
|---|---|---|
| *Millions of shares* | 2016 | 2015 |
| Issued | 1,070 | 1,071 |
| In treasury | (204) | (215) |
| Total shares of common stock outstanding | 866 | 856 |

Our Board of Directors has authorized a program to repurchase our common stock from time to time. 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. There were no repurchases made under the program during the years ended December 31, 2016 and 2015. Approximately $5.7 billion remains authorized for repurchases as of December 31, 2016. From the inception of this program in February 2006 through December 31, 2016, we repurchased approximately 201 million shares of our common stock for a total cost of approximately $8.4 billion.

***Preferred stock***

Our preferred stock consists of five million total authorized shares at December 31, 2016, of which none are issued.

***Accumulated other comprehensive loss***

Accumulated other comprehensive loss consisted of the following:

| | December 31 | |
|---|---|---|
| *Millions of dollars* | 2016 | 2015 |
| Defined benefit and other postretirement liability adjustments (a) | $ (313) | $ (221) |
| Cumulative translation adjustment | (80) | (78) |
| Other | (61) | (64) |
| Total accumulated other comprehensive loss | $ (454) | $ (363) |

(a) Included net actuarial losses for our international pension plans of $290 million at December 31, 2016 and $205 million at December 31, 2015.

**Note 12. Stock-based Compensation**

The following table summarizes stock-based compensation costs for the years ended December 31, 2016, 2015 and 2014.

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of dollars* | 2016 | 2015 | 2014 |
| Stock-based compensation cost | $ 262 | $ 294 | $ 298 |
| Tax benefit | (77) | (99) | (90) |
| Stock-based compensation cost, net of tax | $ 185 | $ 195 | $ 208 |

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 187 million shares of common stock have been reserved for issuance to employees and non-employee directors. At December 31, 2016, approximately 10 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-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.

The following table represents our stock options activity during 2016.

| | 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, 2016 | 20.0 | $ 43.90 | | |
| Granted | 3.8 | 41.18 | | |
| Exercised | (2.2) | 35.93 | | |
| Forfeited/expired | (1.0) | 49.06 | | |
| Outstanding at December 31, 2016 | 20.6 | $ 44.01 | 6.8 | $ 239 |
| Exercisable at December 31, 2016 | 13.0 | $ 43.26 | 5.7 | $ 161 |

The total intrinsic value of options exercised was $25 million in 2016, $9 million in 2015 and $151 million in 2014. As of December 31, 2016, there was $64 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 issuance of common stock was $186 million during 2016, $167 million during 2015 and $332 million during 2014, of which $80 million, $23 million and $186 million related to proceeds from exercises of stock options in 2016, 2015 and 2014, respectively. The remainder relates to cash proceeds from the issuance of shares related to our employee stock purchase plan.

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 | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Expected term (in years) | 5.21 | 5.16 | 5.23 |
| Expected volatility | 37% | 39% | 37% |
| Expected dividend yield | 1.35 - 2.46% | 1.51 - 1.85% | 0.94 - 1.77% |
| Risk-free interest rate | 1.13 - 1.84% | 1.43 - 1.72% | 1.57 - 1.86% |
| Weighted average grant-date fair value per share | $12.33 | $13.47 | $19.26 |

***Restricted stock***

Restricted shares issued under the Stock Plan are restricted as to sale or disposition. These restrictions lapse periodically generally over a period of five 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.

The following table represents our restricted stock awards and restricted stock units granted, vested and forfeited during 2016.

| | Number of Shares (in millions) | Weighted Average Grant-Date Fair Value per Share |
|---|---|---|
| Nonvested shares at January 1, 2016 | 16.5 | $ 45.59 |
| Granted | 5.5 | 42.87 |
| Vested | (5.3) | 44.43 |
| Forfeited | (1.6) | 46.05 |
| Nonvested shares at December 31, 2016 | 15.1 | $ 44.96 |

The weighted average grant-date fair value of shares granted during 2015 was $43.24 and during 2014 was $58.21. The total fair value of shares vested during 2016 was $223 million, during 2015 was $211 million and during 2014 was $278 million. As of December 31, 2016, there was $468 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 three 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. The ESPP contains 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, 74 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, 2016, 43 million shares have been sold through the ESPP since the inception of the plan and 31 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 | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Expected volatility | 36% | 35% | 23% |
| Expected dividend yield | 1.87% | 1.82% | 1.07% |
| Risk-free interest rate | 0.25% | 0.01% | 0.04% |
| Weighted average grant-date fair value per share | $ 8.61 | $ 8.62 | $ 11.80 |

## Note 13. Income per Share

Basic income or loss 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. Antidilutive securities represent potentially dilutive securities which are excluded from the computation of diluted income or loss per share as their impact was antidilutive.

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

| | Year Ended December 31 | | |
|---|---|---|---|
| *Millions of shares* | 2016 | 2015 | 2014 |
| Basic weighted average common shares outstanding | 861 | 853 | 848 |
| Dilutive effect of awards granted under our stock incentive plans | — | — | 4 |
| Diluted weighted average common shares outstanding | 861 | 853 | 852 |
| Antidilutive shares: | | | |
| Options with exercise price greater than the average market price | 11 | 10 | 2 |
| Options which are antidilutive due to net loss position | 1 | 2 | — |
| Total antidilutive shares | 12 | 12 | 2 |

## Note 14. Financial Instruments and Risk Management

At December 31, 2016, we held $92 million of investments in fixed income securities with maturities ranging from less than one year to May 2019, of which $56 million are classified as “Other current assets” and $36 million are classified as “Other assets” on our consolidated balance sheets. At December 31, 2015, we held $96 million of investments in fixed income securities, of which $63 million are classified as "Other current assets" and $33 million are classified as "Other assets" on our consolidated balance sheets. These securities consist primarily of corporate bonds and other debt instruments, are accounted for as available-for-sale and are recorded at fair value based on quoted prices for identical assets in less active markets, which are categorized within level 2 on the fair value hierarchy.

During the second quarter of 2016, we executed a financing agreement with our primary customer in Venezuela, resulting in an exchange of $200 million of outstanding trade receivables for an interest-bearing promissory note. We recorded the note at its fair market value at the date of exchange, resulting in a $148 million pre-tax loss on exchange. Fair value was based on pricing data points for similar assets in an illiquid market and is categorized within level 3 on the fair value hierarchy. We are using an effective interest method to accrete the carrying amount to its par value as it matures. This accretion income is being recorded through “Interest expense, net of interest income” on our consolidated statements of operations. As of December 31, 2016, the carrying amount of this promissory note was $70 million and approximates its fair value. This amount consists of a current portion of $29 million and non-current portion of $41 million, which are classified as “Receivables” and “Other assets,” respectively, on our consolidated balance sheets. In the fourth quarter of 2016, we agreed to exchange this promissory note for a new note with the same maturity and coupon, but which is expected to be tradeable in a more liquid market. We intend to hold the new note to maturity.

We have no financial instruments categorized within level 1 on the fair value hierarchy based on quoted prices in active markets. 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, including current maturities, is as follows:

| | December 31, 2016 | | | | December 31, 2015 | | | |
|---|---|---|---|---|---|---|---|---|
| *Millions of dollars* | Level 1 | Level 2 | Total fair value | Carrying value | Level 1 | Level 2 | Total fair value | Carrying value |
| Long-term debt | $ 753 | $ 12,812 | $ 13,565 | $ 12,377 | $ 1,009 | $ 14,947 | $ 15,956 | $ 15,346 |

Our debt categorized within level 1 on the fair value hierarchy is calculated using quoted prices in active markets for identical liabilities with transactions occurring on the last two days of year-end. Our debt categorized within level 2 on the fair value hierarchy is 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. Our total fair value and carrying value of debt decreased in 2016 compared to 2015 associated with the $2.5 billion of senior notes mandatorily redeemed and $600 million of senior notes repaid during the year. Additionally, differences between the periods presented in our level 1 and level 2 classification of our long-term debt relate to the timing of when transactions are executed. We have no debt categorized within level 3 on the fair value hierarchy based on unobservable inputs.

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, 2016 or December 31, 2015. The counterparties to our derivatives are primarily 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. 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 certain countries in which we do business internationally. 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 $603 million at December 31, 2016 and $619 million at December 31, 2015. 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 existing 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 $12.4 billion at December 31, 2016 and $15.3 billion at December 31, 2015, with $163 million maturing in 2017. We also had $36 million of long-term investments in fixed income securities at December 31, 2016 with maturities that extend through May 2019.

We maintain an interest rate management strategy that is intended to mitigate the exposure to changes in interest rates in the aggregate for our debt 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 4.5% as of December 31, 2016. 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, 2016 and December 31, 2015. The fair value of our interest rate swaps is categorized within level 2 on the fair value hierarchy and 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. 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, 2016, we had fixed rate debt aggregating $10.9 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. Our revenue is generated from selling products and providing services to the energy industry. Our trade receivables are from a broad and diverse group of customers and are generally not collateralized. As of December 31, 2016, 28% of our gross trade receivables were in the United States and 15% were in Venezuela, compared to 26% in the United States and 14% in Venezuela at December 31, 2015. We maintain an allowance for losses based upon the expected collectability of all trade accounts receivable. See Note 5 for further information.

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 15. 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 $111 million in 2016, $288 million in 2015 and $347 million in 2014. The decreases resulted from suspension of discretionary contributions in 2016 and company-wide reductions in workforce during 2016 and 2015;
- 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, 2016, the projected benefit obligation was $1.1 billion and the fair value of plan assets was $865 million, which resulted in an unfunded obligation of $241 million. At December 31, 2015, the projected benefit obligation was $1.0 billion and the fair value of plan assets was $872 million, which resulted in an unfunded obligation of $174 million. The accumulated benefit obligation for our international plans was $1.1 billion at December 31, 2016 and $990 million at December 31, 2015.

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

| Millions of dollars | December 31 2016 | 2015 |
|---|---|---|
| **Amounts recognized on the Consolidated Balance Sheets** | | |
| Accrued employee compensation and benefits | $ 16 | $ 20 |
| Employee compensation and benefits | 227 | 155 |
| **Pension plans in which projected benefit obligation exceeded plan assets** | | |
| Projected benefit obligation | $ 1,083 | $ 1,042 |
| Fair value of plan assets | 840 | 867 |
| **Pension plans in which accumulated benefit obligation exceeded plan assets** | | |
| Accumulated benefit obligation | $ 1,037 | $ 964 |
| Fair value of plan assets | 840 | 846 |

***Fair value measurements of plan assets***

The fair value of our plan assets categorized within level 1 on the fair value hierarchy is based on quoted prices in active markets for identical assets. The fair value of our plan assets categorized within level 2 on the fair value hierarchy is based on significant observable inputs for similar assets. The fair value of our plan assets categorized within level 3 on the fair value hierarchy is based on significant unobservable inputs.

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

| *Millions of dollars* | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash and equivalents | $ — | $ 49 | $ — | $ 49 |
| Common/collective trust funds (a) | | | | |
| Equity funds (b) | — | 197 | — | 197 |
| Bond funds (c) | — | 232 | 44 | 276 |
| Alternatives funds (d) | — | 221 | — | 221 |
| Real estate funds (e) | — | 36 | 35 | 71 |
| Other assets | 5 | 20 | 26 | 51 |
| Fair value of plan assets at December 31, 2016 | $ 5 | $ 755 | $ 105 | $ 865 |
| | | | | |
| Cash and equivalents | $ — | $ 46 | $ — | $ 46 |
| Common/collective trust funds (a) | | | | |
| Equity funds (b) | — | 209 | — | 209 |
| Bond funds (c) | — | 212 | 38 | 250 |
| Alternatives fund (d) | — | 231 | — | 231 |
| Real estate funds (e) | — | 42 | 46 | 88 |
| Other assets | 2 | 19 | 27 | 48 |
| Fair value of plan assets at December 31, 2015 | $ 2 | $ 759 | $ 111 | $ 872 |

(a) Common/collective trust funds are valued at the net asset value of units held by the plans at year-end.
(b) Strategy is to invest in diversified funds of global common stocks.
(c) Strategy is to invest in diversified funds of fixed income securities of varying geographies and credit quality and whose cash flows approximate the maturities of the benefit obligation.
(d) Strategy is to invest in a fund of diversifying investments, including but not limited to reinsurance, commodities and currencies.
(e) Strategy is to invest in diversified funds of real estate investment trusts and private real estate.

Our investment strategy varies by country depending on the circumstances of the underlying 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. Our investment strategy for our United Kingdom pension plan, which constituted 84% of our international pension plans' projected benefit obligation at December 31, 2016 and is no longer accruing service benefits, aims to achieve full funding of the benefit obligation, with the plan's assets increasingly composed of investments whose cash flows match the maturities of the obligation.

***Net periodic benefit cost***

Net periodic benefit cost for our international pension plans was $30 million in 2016, $42 million in 2015 and $36 million in 2014. Included in net periodic benefit cost were $8 million in 2016 and $9 million in 2015 of net curtailment and settlement cost arising from reductions in workforce during these years.

***Actuarial assumptions***

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

| | 2016 | 2015 |
|---|---|---|
| Discount rate | 2.9% | 4.2% |
| Rate of compensation increase | 4.8% | 5.4% |

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:

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Discount rate | 4.2% | 4.1% | 4.8% |
| Expected long-term return on plan assets | 5.3% | 5.9% | 6.4% |
| Rate of compensation increase | 5.4% | 5.3% | 5.4% |

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. Where possible, 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 $15 million to our international pension plans in 2017.

*Benefit payments.* The following table presents expected benefit payments over the next 10 years for our international pension plans.

| *Millions of dollars* | | |
|---|---|---|
| 2017 | $ | 55 |
| 2018 | | 46 |
| 2019 | | 49 |
| 2020 | | 50 |
| 2021 | | 54 |
| Years 2022 - 2026 | | 317 |

**Note 16. New Accounting Pronouncements**

**Standards adopted in 2016**

*Consolidation*

On January 1, 2016, we adopted an accounting standards update issued by the Financial Accounting Standards Board (FASB) related to the consolidation analysis, which amended the guidelines for determining whether certain legal entities should be consolidated. This update eliminated the presumption that a general partner should consolidate a limited partnership and modified the evaluation of whether limited partnerships are variable interest entities or voting interest entities. The adoption of this update did not materially impact our consolidated financial statements.

*Business Combinations*

On January 1, 2016, we adopted an accounting standards update issued by the FASB which simplifies the accounting for measurement-period adjustments for an acquirer in a business combination. The update requires an acquirer to recognize any adjustments to provisional amounts of the initial accounting for a business combination with a corresponding adjustment to goodwill in the reporting period in which the adjustments are determined in the measurement period, as opposed to revising prior periods presented in financial statements. Thus, an acquirer shall adjust its financial statements as needed, including recognizing in its current-period earnings the full effect of changes in depreciation, amortization, or other income effects, by line item, if any, as a result of the change to the provisional amounts calculated as if the accounting had been completed at the acquisition date. The adoption of this update did not impact our consolidated financial statements.

**Standards not yet adopted**

*Revenue Recognition*

In May 2014, the FASB and the International Accounting Standards Board (IASB) issued a comprehensive new revenue recognition standard that will supersede existing revenue recognition guidance under United States Generally Accepted Accounting Principles (U.S. GAAP) and International Financial Reporting Standards (IFRS). The issuance of this guidance completes the joint effort by the FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for U.S. GAAP and IFRS. In August 2015, the FASB issued an accounting standards update for a one-year deferral of the revenue recognition standard's effective date for all entities, which changed the effectiveness to annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard creates a five step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard’s application impact to individual financial statement line items.

We are currently determining the impacts of the new standard on our contract portfolio. Our approach includes performing a detailed review of key contracts representative of our different businesses and comparing historical accounting policies and practices to the new standard. Because the standard will impact our business processes, systems and controls, we are also developing a comprehensive change management project plan to guide the implementation. Our services are primarily short-term in nature, and our assessment at this stage is that we do not expect the new revenue recognition standard will have a material impact on our financial statements upon adoption. We are still evaluating software contracts within our Landmark Software and Services product service line and long-term, fixed pricing contracts requiring integrated project management services within our Consulting and Project Management product service line for potential impact from the new accounting guidance. We currently intend on adopting the new standard utilizing the modified retrospective method that will result in a cumulative effect adjustment as of January 1, 2018.

*Inventory*

In July 2015, the FASB issued an accounting standards update to simplify the measurement of inventory, which requires inventory measured using the first in, first out (FIFO) or average cost methods to be subsequently measured at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation. Currently, these inventory methods are required to be subsequently measured at the lower of cost or market. "Market" could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. This update will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, and will be applied prospectively. We evaluated this new accounting standard and determined it will not have an impact on our consolidated financial statements.

*Leases*

In February 2016, the FASB issued an accounting standards update related to accounting for leases, which requires the assets and liabilities that arise from leases to be recognized on the balance sheet. Currently only capital leases are recorded on the balance sheet. This update will require the lessee to recognize a lease liability equal to the present value of the lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for all leases longer than 12 months. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election by class of underlying asset not to recognize lease assets and liabilities and recognize the lease expense for such leases generally on a straight-line basis over the lease term. This update will be effective for fiscal periods beginning after December 15, 2018, including interim periods within that reporting period. Early adoption is permitted. We are currently evaluating the impact that this update will have on our consolidated financial statements.

*Stock-Based Compensation*

In March 2016, the FASB issued an accounting standards update to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. In addition, an entity can make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest, which is the current U.S. GAAP practice, or account for forfeitures when they occur. This update will be effective for fiscal periods beginning after December 15, 2016, including interim periods within that reporting period. The element of the new standard that will have the most impact on our financial statements will be income tax consequences. Excess tax benefits and tax deficiencies on stock-based compensation awards will now be included in our tax provision within our consolidated statement of operations as discrete items in the reporting period in which they occur, rather than our current accounting of recording in additional paid-in capital on our consolidated balance sheets. We have also elected to continue our current policy of estimating forfeitures of stock-based compensation awards at the time of grant and revising in subsequent periods to reflect actual forfeitures, which is allowable under the new standard.

*Income Taxes*

In October 2016, the FASB issued an accounting standards update to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. Under current U.S. GAAP, the recognition of current and deferred income taxes for an intra-entity asset transfer is prohibited until the asset has been sold to an outside party. Under the new standard, an entity will recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. Two common examples of assets included in the scope of this update are intellectual property and property, plant and equipment. The amendments in this update are effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within those annual reporting periods. The amendments should be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. We have elected to early adopt this standard effective January 1, 2017, and upon adoption, approximately $353 million will be recorded directly to retained earnings representing our cumulative-effect adjustment.

**HALLIBURTON COMPANY**
**Selected Financial Data**
*(Unaudited)*

| | Year ended December 31 | | | | |
|---|---|---|---|---|---|
| *Millions of dollars except per share* | 2016 | 2015 | 2014 | 2013 | 2012 |
| Revenue | $ 15,887 | $ 23,633 | $ 32,870 | $ 29,402 | $ 28,503 |
| Operating income (loss) | (6,778) | (165) | 5,097 | 3,138 | 4,159 |
| Income (loss) from continuing operations | (5,767) | (662) | 3,437 | 2,116 | 2,587 |
| Basic income (loss) per share from continuing operations | (6.69) | (0.78) | 4.05 | 2.35 | 2.78 |
| Diluted income (loss) per share from continuing operations | (6.69) | (0.78) | 4.03 | 2.33 | 2.78 |
| Cash dividends per share | 0.72 | 0.72 | 0.63 | 0.525 | 0.36 |
| Net working capital | 7,654 | 14,733 | 8,781 | 8,678 | 8,334 |
| Total assets | 27,000 | 36,942 | 32,165 | 29,223 | 27,410 |
| Long-term debt (including current maturities) | 12,377 | 15,346 | 7,779 | 7,816 | 4,820 |
| Total shareholders' equity | 9,448 | 15,495 | 16,298 | 13,615 | 15,790 |
| Capital expenditures | 798 | 2,184 | 3,283 | 2,934 | 3,566 |

**HALLIBURTON COMPANY**
**Quarterly Data and Market Price Information**
*(Unaudited)*

| *Millions of dollars except per share data* | Quarter First | Second | Third | Fourth | Year |
|---|---|---|---|---|---|
| **2016** | | | | | |
| Revenue | $ 4,198 | $ 3,835 | $ 3,833 | $ 4,021 | $ 15,887 |
| Operating income (loss) | (3,079) | (3,880) | 128 | 53 | (6,778) |
| Net income (loss) | (2,418) | (3,205) | 7 | (153) | (5,769) |
| Amounts attributable to company shareholders: | | | | | |
| Income (loss) from continuing operations | (2,410) | (3,208) | 6 | (149) | (5,761) |
| Loss from discontinued operations | (2) | — | — | — | (2) |
| Net income (loss) attributable to company | (2,412) | (3,208) | 6 | (149) | (5,763) |
| Basic and diluted net income (loss) per share | (2.81) | (3.73) | 0.01 | (0.17) | (6.69) |
| Cash dividends paid per share | 0.18 | 0.18 | 0.18 | 0.18 | 0.72 |
| Common stock prices (1) | | | | | |
| High | 36.74 | 46.69 | 46.90 | 56.08 | 56.08 |
| Low | 27.64 | 33.26 | 40.12 | 44.23 | 27.64 |
| **2015** | | | | | |
| Revenue | $ 7,050 | $ 5,919 | $ 5,582 | $ 5,082 | $ 23,633 |
| Operating income (loss) | (548) | 254 | 43 | 86 | (165) |
| Net income (loss) | (641) | 53 | (53) | (26) | (667) |
| Amounts attributable to company shareholders: | | | | | |
| Income (loss) from continuing operations | (639) | 55 | (54) | (28) | (666) |
| Loss from discontinued operations | (4) | (1) | — | — | (5) |
| Net income (loss) attributable to company | (643) | 54 | (54) | (28) | (671) |
| Basic income per share attributable to company shareholders: | | | | | |
| Income (loss) from continuing operations | (0.75) | 0.06 | (0.06) | (0.03) | (0.78) |
| Loss from discontinued operations | (0.01) | — | — | — | (0.01) |
| Net income (loss) | (0.76) | 0.06 | (0.06) | (0.03) | (0.79) |
| Diluted income per share attributable to company shareholders: | | | | | |
| Income (loss) from continuing operations | (0.75) | 0.06 | (0.06) | (0.03) | (0.78) |
| Loss from discontinued operations | (0.01) | — | — | — | (0.01) |
| Net income (loss) | (0.76) | 0.06 | (0.06) | (0.03) | (0.79) |
| Cash dividends paid per share | 0.18 | 0.18 | 0.18 | 0.18 | 0.72 |
| Common stock prices (1) | | | | | |
| High | 44.92 | 50.20 | 43.71 | 41.28 | 50.20 |
| Low | 37.27 | 42.46 | 30.93 | 32.13 | 30.93 |

Note: Results for 2016 and 2015 include Baker Hughes related costs and termination fee and impairments and other charges. See Note 2 and Note 3 for further information.

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

## PART III

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

The information required for the directors of the Registrant is incorporated by reference to the Halliburton Company Proxy Statement for our 2017 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 5 through 6 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 2017 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 2017 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 2017 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 2017 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 2016,” “Outstanding Equity Awards at Fiscal Year End 2016,” “2016 Option Exercises and Stock Vested,” “2016 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 2017 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 2017 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 2017 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 2017 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 2017 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 September 14, 2016 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed September 16, 2016, 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). |

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| 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 2.00% Senior Notes due 2018 (included as part of Exhibit 4.26).

4.28 Form of Global Note for Halliburton's 3.50% Senior Notes due 2023 (included as part of Exhibit 4.26).

4.29 Form of Global Note for Halliburton's 4.75% Senior Notes due 2043 (included as part of Exhibit 4.26).

4.30 Eighth Supplemental Indenture, dated as of November 13, 2015, 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 to Halliburton's Form 8-K filed November 13, 2015, File No. 001-03492).

4.31 Form of Global Note for Halliburton's 3.800% Senior Notes due 2025 (included as part of Exhibit 4.30).

4.32 Form of Global Note for Halliburton's 4.850% Senior Notes due 2035 (included as part of Exhibit 4.30).

4.33 Form of Global Note for Halliburton's 5.000% Senior Notes due 2045 (included as part of Exhibit 4.30).

† 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).

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| † | 10.4 | 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). |
| † | 10.5 | 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). |
| † | 10.6 | 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). |
| | 10.7 | 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). |
| | 10.8 | 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). |
| | 10.9 | 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). |
| | 10.10 | 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). |
| † | 10.11 | 2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 001-03492). |
| † | 10.12 | Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 001-03492). |
| † | 10.13 | Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.5 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 001-03492). |
| † | 10.14 | Halliburton Company Pension Equalizer Plan, as amended and restated effective March 1, 2007 (incorporated by reference to Exhibit 10.8 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 001-03492). |
| † | 10.15 | 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). |
| † | 10.16 | Retirement Plan for the Directors of Halliburton Company, as amended and restated effective July 1, 2007 (incorporated by reference to Exhibit 10.10 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 001-03492). |
| † | 10.17 | Employment Agreement (James S. Brown) (incorporated by reference to Exhibit 10.36 to Halliburton's Form 10-K for the year ended December 31, 2007, File No. 001-03492). |
| † | 10.18 | Executive Agreement (Lawrence J. Pope) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed December 12, 2008, File No. 001-03492). |

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| † | 10.19 | Halliburton Company Stock and Incentive Plan, as amended and restated effective February 24, 2015 (incorporated by reference to Appendix B of Halliburton's proxy statement filed April 7, 2015, File No. 001-03492). |
| † | 10.20 | Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 24, 2015 (incorporated by reference to Appendix C of Halliburton's proxy statement filed April 7, 2015, File No. 001-03492). |
| † | 10.21 | Form of Restricted Stock Agreement (incorporated by reference as Exhibit 99.3 of Halliburton's Form S-8 filed July 24, 2015, Registration No. 333-205842). |
| † | 10.22 | Form of Restricted Stock Unit Agreement (incorporated by reference as Exhibit 99.4 of Halliburton's Form S-8 filed July 24, 2015, Registration No. 333-205842). |
| † | 10.23 | Form of Non-Employee Director Restricted Stock Unit Agreement (Director Plan) (incorporated by reference as Exhibit 99.8 of Halliburton's Form S-8 filed July 24, 2015, Registration No. 333-205842). |
| † | 10.24 | 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). |
| † | 10.25 | 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). |
| † | 10.26 | 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). |
| † | 10.27 | 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). |
| † | 10.28 | 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). |
| † | 10.29 | 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). |
| † | 10.30 | 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). |
| | 10.31 | U.S. $3,000,000,000 Five Year Revolving Credit Agreement among Halliburton Company, as Borrower, the Banks party thereto, and Citibank, N.A., as Agent, effective July 21, 2015 (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended June 30, 2015, File No. 001-03492). |
| † | 10.32 | 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). |
| † | 10.33 | Executive Agreement (Eric Carre) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended June 30, 2016, File No. 001-03492). |

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|---|---|---|
| † | 10.34 | 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). |
| † | 10.35 | 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). |
| † | 10.36 | Form of Non-Employee Director Restricted Stock Unit Agreement (Stock and Incentive Plan) (incorporated by reference as Exhibit 99.9 of Halliburton's Form S-8 filed July 24, 2015, Registration No. 333-205842). |
| † | 10.37 | 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). |
| † | 10.38 | 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). |
| † | 10.39 | 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). |
| † | 10.40 | 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). |
| † | 10.41 | 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). |
| † | 10.42 | Executive Agreement (Robb L. Voyles) (incorporated by reference to Exhibit 10.48 to Halliburton’s Form 10-K filed February 7, 2014, File No. 001-03492). |
| † | 10.43 | Executive Agreement (Timothy McKeon) (incorporated by reference to Exhibit 10.49 to Halliburton’s Form 10-K filed February 7, 2014, File No. 001-03492). |
| † | 10.44 | Executive Agreement (Charles E. Geer, Jr.) (incorporated by reference to Exhibit 10.2 to Halliburton’s Form 8-K filed December 9, 2014, File No. 001-03492). |
| | 10.45 | HESI Punitive Damages and Assigned Claims Settlement Agreement dated September 2, 2014, entered into between Halliburton Company and Halliburton Energy Services, Inc. and counsel for The Plaintiffs Steering Committee in MDL 2179 and the Deepwater Horizon Economic and Property Damages Settlement Class (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2014, File No. 001-03492). |
| † | 10.46 | Form of Non-Employee Director Restricted Stock Agreement (Directors Plan) (incorporated by reference as Exhibit 99.5 of Halliburton's Form S-8 filed May 21, 2009, Registration No. 333-159394). |
| † | 10.47 | Form of Non-Employee Director Restricted Stock Agreement (Stock and Incentive Plan) (incorporated by reference to Exhibit 10.43 to Halliburton's Form 10-K for the year ended December 31, 2011, Registration No. 001-03492). |
| | 10.48 | Termination Agreement, dated as of April 30, 2016, between the Company and Baker Hughes (incorporated by reference to Exhibit 10.1 to Halliburton’s Form 8-K filed May 4, 2016, File No. 001-03492). |

| | | |
|---|---|---|
| † | 10.49 | Amendment No. 2 to Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2016, File No. 001-03492). |
| † | 10.50 | Second Amendment to Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended September 30, 2016, File No. 001-03492). |
| † | 10.51 | Form of Nonstatutory Stock Option Agreement (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended September 30, 2016, File No. 001-03492). |
| * | 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 2017:<br>Abdulaziz F. Al Khayyal<br>William E. Albrecht<br>Alan M. Bennett<br>James R. Boyd<br>Milton Carroll<br>Nance K. Dicciani<br>Murry S. Gerber<br>José C. Grubisich<br>Robert A. Malone<br>J. Landis Martin<br>Jeffrey A. Miller<br>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, 2017.

**HALLIBURTON COMPANY**

By /s/ David J. Lesar
David J. Lesar
Chairman of the Board 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, 2017.

| Signature | Title |
|---|---|
| /s/ David J. Lesar<br>David J. Lesar | Chairman of the Board, Director and<br>Chief Executive Officer |
| /s/ Mark A. McCollum<br>Mark A. McCollum | Executive Vice President and<br>Chief Financial Officer |
| /s/ Charles E. Geer, Jr.<br>Charles E. Geer, Jr. | Vice President and<br>Corporate Controller |

| Signature | Title |
|---|---|
| * Abdulaziz F. Al Khayyal<br>Abdulaziz F. Al Khayyal | Director |
| * William E. Albrecht<br>William E. Albrecht | Director |
| * Alan M. Bennett<br>Alan M. Bennett | Director |
| * James R. Boyd<br>James R. Boyd | Director |
| * Milton Carroll<br>Milton Carroll | Director |
| * Nance K. Dicciani<br>Nance K. Dicciani | Director |
| * Murry S. Gerber<br>Murry S. Gerber | Director |
| * José C. Grubisich<br>José C. Grubisich | Director |
| * Robert A. Malone<br>Robert A. Malone | Director |
| * J. Landis Martin<br>J. Landis Martin | Director |
| * Jeffrey A. Miller<br>Jeffrey A. Miller | President and Director |
| * Debra L. Reed<br>Debra L. Reed | Director |

/s/ Robb L. Voyles
*By Robb L. Voyles, Attorney-in-fact

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## Shares Listed

New York Stock Exchange
Symbol: HAL

## Transfer Agent & Registrar

Computershare Shareowner Services
211 Quality Circle, Suite 210
College Station, TX 77845
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

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