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

FORM 10-K

☒ **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 1-13926

DIAMOND OFFSHORE DRILLING, INC.
(Exact name of registrant as specified in its charter)

Delaware	**76-0321760**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

15415 Katy Freeway
Houston, Texas 77094
(Address and zip code of principal executive offices)

(281) 492-5300
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value 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 ☒ 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 ☒

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

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

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

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

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second fiscal quarter.

As of June 30, 2016 $1,558,351,487

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of February 10, 2017 Common Stock, $0.01 par value per share 137,169,663 shares

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2017 Annual Meeting of Stockholders of Diamond Offshore Drilling, Inc., which will be filed within 120 days of December 31, 2016, are incorporated by reference in Part III of this report.

DIAMOND OFFSHORE DRILLING, INC.

FORM 10-K for the Year Ended December 31, 2016

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PART I

Item 1. Business.

General

Diamond Offshore Drilling, Inc. provides contract drilling services to the energy industry around the globe with a fleet of 24 offshore drilling rigs. Our current fleet consists of four drillships, 19 semisubmersible rigs, and one jack-up rig. *See* "— Our Fleet — *Fleet Enhancements and Additions*" and "— Our Fleet — *Floater Fleet Status*."

Unless the context otherwise requires, references in this report to "Diamond Offshore," "we," "us" or "our" mean Diamond Offshore Drilling, Inc. and our consolidated subsidiaries. Diamond Offshore Drilling, Inc. was incorporated in Delaware in 1989.

Our Fleet

Our diverse fleet enables us to offer a broad range of services worldwide, primarily in the floater market (ultra-deepwater, deepwater and mid-water).

Floaters. A floater rig is a type of mobile offshore drilling unit that floats and does not rest on the seafloor. This asset class includes self-propelled drillships and semisubmersible rigs. Semisubmersible rigs consist of an upper working and living deck resting on vertical columns connected to lower hull members. Such rigs operate in a "semi-submerged" position, remaining afloat, off bottom, in a position in which the lower hull is approximately 55 feet to 90 feet below the water line and the upper deck protrudes well above the surface. Semisubmersibles hold position while drilling by use of a series of small propulsion units or thrusters that provide dynamic positioning, or DP, to keep the rig on location, or with anchors tethered to the sea bed. Although DP semisubmersibles are self-propelled, such rigs may be moved long distances with the assistance of tug boats. Non-DP, or moored, semisubmersibles require tug boats or the use of a heavy lift vessel to move between locations.

A drillship is an adaptation of a maritime vessel that is designed and constructed to carry out drilling operations by means of a substructure with a moon pool centrally located in the hull. Drillships are typically self-propelled and are positioned over a drillsite through the use of a DP system similar to those used on semisubmersible rigs.

Our floater fleet (semisubmersibles and drillships) can be further categorized based on the nominal water depth for each class of rig as follows:

Category	Rated Water Depth [a] (in feet)	Number of Units in Our Fleet
Ultra-Deepwater	7,501 to 12,000	12
Deepwater	5,000 to 7,500	6
Mid-Water	400 to 4,999	5

(a) Rated water depth for semisubmersibles and drillships reflects the maximum water depth in which a floating rig has been designed to operate. However, individual rigs are capable of drilling, or have drilled, in marginally greater water depths depending on various conditions (such as salinity of the ocean, weather and sea conditions).

Floater Fleet Status

The following table presents additional information regarding our floater fleet at January 30, 2017:

Rig Type and Name	Rated Water Depth (in feet)	Attributes	Year Built/ Redelivered (a)	Current Location (b)	Customer (c)
ULTRA-DEEPWATER:					
Drillships (4):					
Ocean BlackLion	12,000	DP; 7R; 15K	2015	GOM	Hess Corporation
Ocean BlackRhino	12,000	DP; 7R; 15K	2014	GOM	Contract preparation/Hess Corporation
Ocean BlackHornet	12,000	DP; 7R; 15K	2014	GOM	Anadarko
Ocean BlackHawk	12,000	DP; 7R; 15K	2014	GOM	Anadarko
Semisubmersibles (8):					
Ocean GreatWhite	10,000	DP; 6R; 15K	2016	Malaysia	BP
Ocean Valor	10,000	DP; 6R; 15K	2009	Brazil	Petrobras (d)
Ocean Courage	10,000	DP; 6R; 15K	2009	Brazil	Petrobras
Ocean Confidence	10,000	DP; 6R; 15K	2001/2015	Canary Islands	Cold Stacked
Ocean Monarch	10,000	15K	2008	Singapore	Survey/Contract preparation
Ocean Endeavor	10,000	15K	2007	Italy	Cold Stacked
Ocean Rover	8,000	15K	2003	Malaysia	Cold Stacked
Ocean Baroness	8,000	15K	2002	GOM	Cold Stacked
DEEPWATER:					
Semisubmersibles (6):					
Ocean Apex	6,000	15K	2014	Australia	Woodside Energy
Ocean Onyx	6,000	15K	2013	GOM	Cold Stacked
Ocean Victory	5,500	15K	1997	Trinidad & Tobago	BP Trinidad
Ocean America	5,500	15K	1988	Malaysia	Cold Stacked
Ocean Valiant	5,500	15K	1988	North Sea/U.K.	Maersk
Ocean Alliance	5,250	DP; 15K	1988	GOM	Cold Stacked
MID-WATER:					
Semisubmersibles (5):					
Ocean Patriot	3,000	15K	1983	North Sea/U.K.	Apache
Ocean Guardian	1,500	15K	1985	North Sea/U.K.	Dana
Ocean Princess	1,500	15K	1975	North Sea/U.K.	Cold Stacked
Ocean Vanguard	1,500	15K	1982	North Sea/U.K.	Cold Stacked
Ocean Nomad	1,200		1975	North Sea/U.K.	Cold Stacked

Attributes

DP	=	Dynamically Positioned/Self-Propelled	7R	=	2 Seven ram blow out preventers
6R	=	Six ram blow out preventer	15K	=	15,000 psi well control system

(a) Represents year rig was built and originally placed in service or year rig was redelivered with significant enhancements that enabled the rig to be classified within a different floater category than originally constructed.

(b) GOM means U.S. Gulf of Mexico.

(c) For ease of presentation in this table, customer names have been shortened or abbreviated.

(d) In August 2016, our subsidiary received notice of termination of its drilling contract from Petróleo Brasileiro S.A., or Petrobras. In the same month, we filed a lawsuit in Brazil, claiming that Petrobras' purported termination of the contract was unlawful and requesting an injunction to prohibit the contract termination. In September 2016, a Brazilian court issued a preliminary injunction, suspending Petrobras' purported termination of the contract and ordering that the contract remain in effect until the end of the term or further court order. Petrobras has appealed the granting of the injunction. We do not believe that Petrobras had a valid or lawful basis for terminating the contract, and we intend to continue to defend our rights under the contract.

Jack-ups. Jack-up rigs are mobile, self-elevating drilling platforms equipped with legs that are lowered to the ocean floor. Our jack-up is used for drilling in water depths from 20 feet to 350 feet. As of January 30, 2017, the *Ocean Scepter*, a cantilevered jack-up drilling rig built in 2008, was offshore Mexico where it was waiting to commence a short-term contract for Fieldwood Energy. The *Ocean Spur*, which was reported as held for sale at the end of 2016, is expected to be sold in the near future.

Fleet Enhancements and Additions. Our long-term strategy is to upgrade our fleet to meet customer demand for advanced, efficient and high-tech rigs by acquiring or building new rigs when possible to do so at attractive prices, and otherwise by enhancing the capabilities of our existing rigs at a lower cost and shorter construction period than newbuild construction would require. Since 2009, commencing with the acquisition of two newbuild, ultra-deepwater semisubmersible rigs, the *Ocean Courage* and *Ocean Valor*, we have spent over $5.0 billion towards upgrading our fleet. In 2016, we took delivery of the *Ocean GreatWhite*, the final rig to be completed during our most recent fleet enhancement cycle.

We will evaluate further rig acquisition and enhancement opportunities as they arise. However, we can provide no assurance whether, or to what extent, we will continue to make rig acquisitions or enhancements to our fleet. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow and Capital Expenditures" in Item 7 of this report.

Pressure Control by the Hour®. During 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide us services with respect to certain blowout preventer and related well control equipment on our four drillships. Such services include management of maintenance, certification and reliability with respect to such equipment. In connection with the services agreement with GE, we sold the equipment to a GE affiliate and have leased back such equipment under four separate ten-year operating leases. Collectively, we refer to the services agreement with GE and the lease agreements with the GE affiliate as the "PCbtH program."

Markets

The principal markets for our offshore contract drilling services are:

- the Gulf of Mexico, including the United States, or U.S., and Mexico;
- South America, principally offshore Brazil, and Trinidad and Tobago;
- Australia and Southeast Asia, including Malaysia, Indonesia and Vietnam;
- Europe, principally offshore the United Kingdom, or U.K., and Norway;
- East and West Africa;
- the Mediterranean; and
- the Middle East.

We actively market our rigs worldwide. From time to time our fleet operates in various other markets throughout the world. See Note 18 "Segments and Geographic Area Analysis" to our Consolidated Financial Statements in Item 8 of this report.

Offshore Contract Drilling Services

Our contracts to provide offshore drilling services vary in their terms and provisions. We typically obtain our contracts through a competitive bid process, although it is not unusual for us to be awarded drilling contracts following direct negotiations. Our drilling contracts generally provide for a basic dayrate regardless of whether or not drilling results in a productive well. Drilling contracts generally also provide for reductions in rates during periods when the rig is being moved or when drilling operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other circumstances. Under dayrate contracts, we generally pay the operating expenses of the rig, including wages and the cost of incidental supplies. Historically, dayrate contracts have accounted for the majority of our revenues. In addition, from time to time, our dayrate contracts may also provide for the ability to earn an incentive bonus from our customer based upon performance.

The duration of a dayrate drilling contract is generally tied to the time required to drill a single well or a group of wells, in what we refer to as a well-to-well contract, or a fixed period of time, in what we refer to as a term contract. Many drilling contracts may be terminated by the customer in the event the drilling unit is destroyed or lost, or if drilling operations are suspended for an extended period of time as a result of a breakdown of equipment or, in some cases, due to events beyond the control of either party to the contract. Certain of our contracts also permit the customer to terminate the contract early by giving notice; in most circumstances this requires the payment of an early termination fee by the customer. The contract term in many instances may also be extended by the customer exercising options for the drilling of additional wells or for an additional length of time, generally at competitive market rates and mutually agreeable terms at the time of the extension. In periods of decreasing demand for offshore rigs, drilling contractors may prefer longer term contracts to preserve dayrates at existing levels and ensure utilization, while customers may prefer shorter contracts that allow them to more quickly obtain the benefit of declining dayrates. Moreover, drilling contractors may accept lower dayrates in a declining market in order to obtain longer-term contracts and add backlog. See "Risk Factors — *We may not be able to renew or replace expiring contracts for our rigs,*" "Risk Factors — *Our business involves numerous operating hazards that could expose us to significant losses and significant damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us,*" "Risk Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized,*" "Risk Factors — *We may enter into drilling contracts that expose us to greater risks than we normally assume*" and "Risk Factors — *We self-insure for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico*" in Item 1A of this report, which are incorporated herein by reference. For a discussion of our contract backlog, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*" in Item 7 of this report, which is incorporated herein by reference.

Customers

We provide offshore drilling services to a customer base that includes major and independent oil and gas companies and government-owned oil companies. During 2016, 2015 and 2014, we performed services for 18, 19 and 35 different customers, respectively. During 2016, 2015 and 2014, our most significant customers were as follows:

	Percentage of Annual Consolidated Revenues		
Customer	**2016**	**2015**	**2014**
Anadarko	22.4%	12.4%	3.6%
Petróleo Brasileiro S.A.	17.9%	24.1%	31.9%
ExxonMobil	5.8%	12.4%	5.0%

No other customer accounted for 10% or more of our annual total consolidated revenues during 2016, 2015 or 2014. See "Risk Factors — *Our industry is highly competitive, with oversupply and intense price competition*" and "Risk Factors — *Our customer base is concentrated"* in Item 1A of this report, which are incorporated herein by reference.

As of January 1, 2017, our contract backlog was $3.6 billion attributable to 11 customers. All four of our drillships are currently contracted to work in the GOM. As of January 1, 2017, contract backlog attributable to our expected operations in the GOM was $639.0 million, $653.0 million, $554.0 million and $85.0 million for the years 2017, 2018, 2019 and 2020, respectively, all of which was attributable to two customers. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*" in Item 7 of this report. See "Risk

Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized*" in Item 1A of this report, which is incorporated herein by reference.

Competition

Despite consolidation in previous years, the offshore contract drilling industry remains highly competitive with numerous industry participants, none of which at the present time has a dominant market share. The industry may also experience additional consolidation in the future, which could create other large competitors. Some of our competitors may have greater financial or other resources than we do. Based on industry data, as of the date of this report, there are approximately 830 mobile drilling rigs in service worldwide, including approximately 290 floater rigs.

The offshore contract drilling industry is influenced by a number of factors, including global economies and demand for oil and natural gas, current and anticipated prices of oil and natural gas, expenditures by oil and gas companies for exploration and development of oil and natural gas and the availability of drilling rigs.

Drilling contracts are traditionally awarded on a competitive bid basis. Price is typically the primary factor in determining which qualified contractor is awarded a job. Customers may also consider rig availability and location, a drilling contractor's operational and safety performance record, and condition and suitability of equipment. We believe we compete favorably with respect to these factors.

We compete on a worldwide basis, but competition may vary significantly by region at any particular time. See "— Markets." Competition for offshore rigs generally takes place on a global basis, as these rigs are highly mobile and may be moved, although at a cost that may be substantial, from one region to another. It is characteristic of the offshore drilling industry to move rigs from areas of low utilization and dayrates to areas of greater activity and relatively higher dayrates. The current oversupply of offshore drilling rigs also intensifies price competition. See "Risk Factors — *Our industry is highly competitive, with oversupply and intense price competition"* in Item 1A of this report, which is incorporated herein by reference.

Governmental Regulation

Our operations are subject to numerous international, foreign, U.S., state and local laws and regulations that relate directly or indirectly to our operations, including regulations controlling the discharge of materials into the environment, requiring removal and clean-up under some circumstances, or otherwise relating to the protection of the environment, and may include laws or regulations pertaining to climate change, carbon emissions or energy use. See "Risk Factors — *We are subject to extensive domestic and international laws and regulations that could significantly limit our business activities and revenues and increase our costs*" and "Risk Factors — *Compliance with or breach of environmental laws can be costly and could limit our operations*" in Item 1A of this report, which are incorporated herein by reference.

Operations Outside the United States

Our operations outside the U.S. accounted for approximately 66%, 79% and 85% of our total consolidated revenues for the years ended December 31, 2016, 2015 and 2014, respectively. See "Risk Factors — *Significant portions of our operations are conducted outside the United States and involve additional risks not associated with United States domestic operations*," "Risk Factors — *We may enter into drilling contracts that expose us to greater risks than we normally assume*," "Risk Factors — *We may be required to accrue additional tax liability on certain of our foreign earnings*" and "Risk Factors — *Fluctuations in exchange rates and nonconvertibility of currencies could result in losses to us*" in Item 1A of this report, which are incorporated herein by reference.

Employees

As of December 31, 2016, we had approximately 2,800 workers, including international crew personnel furnished through independent labor contractors.

Executive Officers of the Registrant

We have included information on our executive officers in Part I of this report in reliance on General Instruction G(3) to Form 10-K. Our executive officers are elected annually by our Board of Directors and serve at the discretion of our Board of Directors until their successors are duly elected and qualified, or until their earlier death, resignation, disqualification or removal from office. Information with respect to our executive officers is set forth below.

Name	Age as of January 31, 2017	Position
Marc Edwards	56	President and Chief Executive Officer and Director
David L. Roland	55	Senior Vice President, General Counsel and Secretary
Thomas Roth	61	Senior Vice President — Worldwide Operations
Ronald Woll	49	Senior Vice President and Chief Commercial Officer
Kelly Youngblood	51	Senior Vice President and Chief Financial Officer
Beth G. Gordon	61	Vice President and Controller

Marc Edwards has served as our President and Chief Executive Officer and as a Director since March 2014. Mr. Edwards previously served as a member of the Executive Committee and as Senior Vice President of the Completion and Production Division at Halliburton Company, a global diversified oilfield services company, from January 2010 to February 2014.

David L. Roland has served as our Senior Vice President, General Counsel and Secretary since September 2014. From April 2004 until joining us in 2014, Mr. Roland served as Senior Vice President, General Counsel and Corporate Secretary of ION Geophysical Corporation, a NYSE-listed geophysical company.

Thomas Roth has served as our Senior Vice President — Worldwide Operations since December 2016. Mr. Roth previously served as Vice President of the Boots & Coots Product Service Line at Halliburton Company from July 2013 to September 2015. Mr. Roth also served as Boots & Coots Global Operations Manager at Halliburton Company from August 2011 to July 2013.

Ronald Woll has served as our Senior Vice President and Chief Commercial Officer since June 2014. Mr. Woll previously served as Senior Vice President — Supply Chain at Halliburton Company from January 2011 through June 2014.

Kelly Youngblood has served as our Senior Vice President and our Chief Financial Officer since May 2016. Mr. Youngblood previously served as Vice President, Investor Relations at Halliburton Company from January 2013 to April 2016. From September 2011 to December 2012, Mr. Youngblood served as Senior Director, Investor Relations at Halliburton Company.

Beth G. Gordon has served as our Vice President and Controller since January 2017 and previously served as our Controller since April 2000.

Access to Company Filings

We are subject to the informational requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and accordingly file annual, quarterly and current reports, any amendments to those reports, proxy statements and other information with the United States Securities and Exchange Commission, or SEC. You may read and copy the information we file with the SEC at the public reference facilities maintained by the SEC at 100 F Street, N.E., Washington, DC 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference room. Our SEC filings are also available to the public from the SEC's Internet site at www.sec.gov or from our Internet site at www.diamondoffshore.com. Our website provides a hyperlink to a third-party SEC filings website where these reports may be viewed and printed at no cost as soon as reasonably practicable after we have electronically filed such material with, or furnished it to, the SEC. The preceding Internet addresses and all other Internet addresses referenced in this report are for information purposes only and are not intended to be a hyperlink. Accordingly, no information found or provided at such Internet addresses or at our website in general (or at other websites linked to our website) is intended or deemed to be incorporated by reference in this report.

Item 1A. Risk Factors.

Our business is subject to a variety of risks and uncertainties. If any of these risks or uncertainties actually occur, our business, financial condition, results of operations and cash flows, and the trading prices of our securities, may be materially and adversely affected. You should carefully consider these risks when evaluating us and our securities. We have described below the most significant risks and uncertainties facing us; however, these risks and uncertainties are not the only ones facing our company. We are also subject to a variety of risks that affect many other companies generally, as well as additional risks and uncertainties not known to us or that, as of the date of this report, we believe are not as significant as the risks described below.

The worldwide demand for drilling services has declined significantly as a result of the decline in oil prices, which commenced during the second half of 2014 and has continued into 2017.

Demand for our drilling services depends in large part upon the oil and natural gas industry's offshore exploration and production activity and expenditure levels, which are directly affected by oil and gas prices and market expectations of potential changes in oil and gas prices. Commencing in the second half of 2014, oil prices have declined precipitously, falling to a 12-year low of less than $30 per barrel in January 2016. Oil prices have recently rebounded to some extent, but continue to exhibit day-to-day volatility. The dramatic reduction in commodity prices has caused a sharp decline in the demand for offshore drilling services, including services that we provide and adversely affected our results of operations and cash flows in 2015 and 2016, compared to previous years. A prolonged period of low oil prices would have a material adverse effect on many of our customers and, therefore, on demand for our services and on our financial condition, results of operations and cash flows.

Oil prices have been, and are expected to continue to be, volatile and are affected by numerous factors beyond our control, including:

- worldwide supply and demand for oil and gas;
- the level of economic activity in energy-consuming markets;
- the worldwide economic environment and economic trends, including recessions and the level of international trade activity;
- the ability of the Organization of Petroleum Exporting Countries, or OPEC, to set and maintain production levels and pricing;
- the level of production in non-OPEC countries;
- civil unrest and the worldwide political and military environment, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities involving the Middle East, Russia, other oil-producing regions or other geographic areas or further acts of terrorism in the United States or elsewhere;
- the cost of exploring for, developing, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves and production;

- available pipeline and other oil and gas transportation and refining capacity;
- the ability of oil and gas companies to raise capital;
- weather conditions, including hurricanes, which can affect oil and gas operations over a wide area;
- natural disasters or incidents resulting from operating hazards inherent in offshore drilling, such as oil spills;
- the policies of various governments regarding exploration and development of their oil and gas reserves;
- technological advances affecting energy consumption, including development and exploitation of alternative fuels or energy sources;
- laws and regulations relating to environmental or energy security matters, including those purporting to address global climate change;
- domestic and foreign tax policy; and
- advances in exploration and development technology.

An increase in commodity demand and prices will not necessarily result in a prompt increase in offshore drilling activity since our customers' project development times, reserve replacement needs and expectations of future commodity demand, prices and supply of available competing rigs all combine to affect demand for our rigs.

Our business depends on the level of activity in the offshore oil and gas industry, which has been cyclical and is significantly affected by many factors outside of our control.

Demand for our drilling services depends upon the level of offshore oil and gas exploration, development and production in markets worldwide, and those activities depend in large part on oil and gas prices, worldwide demand for oil and gas and a variety of political and economic factors. The level of offshore drilling activity is adversely affected when operators reduce or defer new investment in offshore projects, reduce or suspend their drilling budgets or reallocate their drilling budgets away from offshore drilling in favor of other priorities, such as shale or other land-based projects, which could reduce demand for our rigs. As a result, our business and the oil and gas industry in general are subject to cyclical fluctuations.

As a result of the cyclical fluctuations in the market, there have been periods of lower demand, excess rig supply and lower dayrates, followed by periods of higher demand, shorter rig supply and higher dayrates. We cannot predict the timing or duration of such fluctuations. Periods of lower demand or excess rig supply, which have occurred in the recent past and are continuing, intensify the competition in the industry and often result in periods of lower utilization and lower dayrates. During these periods, our rigs may not obtain contracts for future work and may be idle for long periods of time or may be able to obtain work only under contracts with lower dayrates or less favorable terms, which could have a material adverse effect on our financial condition, results of operations and cash flows during these periods. Additionally, prolonged periods of low utilization and dayrates could also result in the recognition of further impairment charges on certain of our drilling rigs if future cash flow estimates, based upon information available to management at the time, indicate that the carrying value of these rigs may not be recoverable. See "— *We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs.*"

Our industry is highly competitive, with oversupply and intense price competition.

The offshore contract drilling industry is highly competitive with numerous industry participants. Some of our competitors may be larger companies, have larger or more technologically advanced fleets and have greater financial or other resources than we do. The drilling industry has experienced consolidation in the past and may experience additional consolidation, which could create additional large competitors. Drilling contracts are traditionally awarded on a competitive bid basis. Price is typically the primary factor in determining which qualified contractor is awarded a job; however, rig availability and location, a drilling contractor's safety record and the quality and technical capability of service and equipment may also be considered.

New rig construction and upgrades of existing drilling rigs, cancelation or termination of drilling contracts and established rigs coming off contract have contributed to the current oversupply of drilling rigs, intensifying price competition. Additional newbuild rigs entering the market are expected to further negatively impact rig utilization and intensify price competition as rigs are delivered. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Floater Markets*" in Item 7 of this report.

Our customer base is concentrated.

We provide offshore drilling services to a customer base that includes major and independent oil and gas companies and government-owned oil companies. During 2016, one of our customers in the GOM, Anadarko, and our five largest customers in the aggregate accounted for 22% and 65%, respectively, of our annual total consolidated revenues. In addition, the number of customers we have performed services for has declined from 35 in 2014 to 18 in 2016. The loss of a significant customer could have a material adverse impact on our financial condition, results of operations and cash flows, especially in a declining market where the number of our working drilling rigs is declining along with the number of our active customers. In addition, if a significant customer experiences liquidity constraints or other financial difficulties, or elects to terminate one of our drilling contracts, it could materially adversely affect our utilization rates in the affected market and also displace demand for our other drilling rigs as the resulting excess supply enters the market. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*" in Item 7 of this report.

We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized.

Generally, our customers may terminate our drilling contracts under certain circumstances, such as the destruction or loss of a drilling rig, if we suspend drilling operations for a specified period of time as a result of a breakdown of major equipment, excessive downtime for repairs, failure to meet minimum performance criteria (including customer acceptance testing) or, in some cases, due to other events beyond the control of either party.

In addition, some of our drilling contracts permit the customer to terminate the contract after specified notice periods, often by tendering contractually specified termination amounts, which may not fully compensate us for the loss of the contract. During depressed market conditions, such as those currently in effect, certain customers have utilized such contract clauses to seek to renegotiate or terminate a drilling contract or claim that we have breached provisions of our drilling contracts in order to avoid their obligations to us under circumstances where we believe we are in compliance with the contracts. For example, in August 2016, Petrobras, the customer for the *Ocean Valor*, delivered a notice of termination of its drilling contract. We are disputing in court the termination attempt as unlawful and have obtained a preliminary injunction against the termination, which Petrobras has appealed. Additionally, because of depressed commodity prices, restricted credit markets, economic downturns, changes in priorities or strategy or other factors beyond our control, a customer may no longer want or need a rig that is currently under contract or may be able to obtain a comparable rig at a lower dayrate. For these reasons, customers may seek to renegotiate the terms of our existing drilling contracts, terminate our contracts without justification or repudiate or otherwise fail to perform their obligations under our contracts. Such renegotiations could include requests to lower the contract dayrate, in some cases, in exchange for additional contract term, shorten the term on one contracted rig in exchange for additional term on another rig, early termination of a contract in exchange for a lump sum payout and many other possibilities. Our contract backlog may be adversely impacted as a result of such contract terminations or renegotiations.

When a customer terminates our contract prior to the contract's scheduled expiration, our contract backlog is adversely impacted, and we might not recover any compensation for the termination or any recovery we might obtain may not fully compensate us for the loss of the contract. In any case, the early termination of a contract may result in our rig being idle for an extended period of time. Each of these results could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, if our customer cancels our contract or if we elect to terminate a contract due to the customer's nonperformance and in either case we are unable to secure a new contract on a timely basis and on substantially similar terms, or if a contract is disputed or suspended for an extended period of time or if a contract is renegotiated, it could materially and adversely affect our financial condition, results of operations and cash flows.

Currently, our reported contract backlog only includes future revenues under firm commitments; however, from time to time, we may report anticipated commitments for which definitive agreements have not yet been, but are expected to be, executed. We can provide no assurance that in such cases we will be able to ultimately execute a definitive agreement. In addition, for the reasons described above, we can provide no assurance that our customers will be willing or able to fulfill their contractual commitments to us.

Our inability to perform our contractual obligations, or our customers' inability or unwillingness to fulfill their contractual commitments to us, may have a material adverse effect on our financial condition, results of operations and cash flows. See "*— Our industry is highly competitive, with oversupply and intense price competition*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Contract Drilling Backlog*" in Item 7 of this report.

We may not be able to renew or replace expiring contracts for our rigs.

As of the date of this report, we have a number of customer contracts that will expire in 2017 and 2018. Our ability to renew or replace expiring contracts or obtain new contracts, and the terms of any such contracts, will depend on various factors, including market conditions and the specific needs of our customers, at such times. Given the historically cyclical and highly competitive nature of our industry, we may not be able to renew or replace the contracts or we may be required to renew or replace expiring contracts or obtain new contracts at dayrates that are below, and potentially substantially below, existing dayrates, or that have terms that are less favorable to us than our existing contracts. Moreover, we may be unable to secure contracts for these rigs. Failure to secure contracts for a rig may result in a decision to cold stack the rig, which puts the rig at risk for impairment and may competitively disadvantage the rig as customers, during the most recent market downturn, have expressed a preference for ready or "hot" stacked rigs over cold-stacked rigs. This could have a material adverse effect on our financial condition, results of operations and cash flows.

We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs.

The current oversupply of drilling rigs in the offshore drilling market has resulted in numerous rigs being idled and in some cases retired and/or scrapped. We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable, and we could incur additional impairment charges related to the carrying value of our drilling rigs. Impairment write-offs could result if, for example, any of our rigs become obsolete or commercially less desirable due to changes in technology, market demand or market expectations or their carrying values become excessive due to the condition of the rig, cold stacking the rig, the expectation of cold stacking the rig in the near future, contracted backlog of less than one year for a rig, a decision to retire or scrap the rig, or excess spending over budget on a new-build construction project or major rig upgrade. We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment, reflecting management's assumptions and estimates regarding the appropriate risk-adjusted dayrate by rig, future industry conditions and operations and other factors. Asset impairment evaluations are, by their nature, highly subjective. The use of different estimates and assumptions could result in materially different carrying values of our assets, which could impact the need to record an impairment charge and the amount of any charge taken. Since 2012, we have retired and sold 20 drilling rigs and recorded impairment losses aggregating $1.6 billion, including $678.1 million recognized in 2016. Historically, the longer a drilling rig remains cold stacked, the higher the cost of reactivation and, depending on the age, technological obsolescence and condition of the rig, the lower the likelihood that the rig will be reactivated at a future date. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Overview — *Critical Accounting Estimates — Property, Plant and Equipment*” in Item 7 of this report and Note 2 “Asset Impairments” to our Consolidated Financial Statements in Item 8 of this report.

We can provide no assurance that our assumptions and estimates used in our asset impairment evaluations will ultimately be realized or that the current carrying value of our property and equipment, including rigs designated as held for sale, will ultimately be realized.

Our contract drilling expense includes fixed costs that will not decline in proportion to decreases in rig utilization and dayrates.

Our contract drilling expense includes all direct and indirect costs associated with the operation, maintenance and support of our drilling equipment, which is often not affected by changes in dayrates and utilization. During periods of reduced revenue and/or activity, certain of our fixed costs will not decline and often we may incur additional operating costs, such as fuel and catering costs, for which we are generally reimbursed by the customer when a rig is under contract. During times of reduced utilization, reductions in costs may not be immediate as we may incur additional costs associated with cold stacking a rig (particularly if we cold stack a newer rig, such as a drillship, for which cold-stacking costs are typically substantially higher than for a jack-up rig or an older floater rig), or we may not be able to fully reduce the cost of our support operations in a particular geographic region due to the need to support the remaining drilling rigs in that region. Accordingly, a decline in revenue due to lower dayrates and/or utilization may not be offset by a corresponding decrease in contract drilling expense and could have a material adverse effect on our financial condition, results of operations and cash flows.

We may enter into drilling contracts that expose us to greater risks than we normally assume.

From time to time, we may enter into drilling contracts with national oil companies, government-controlled entities or others that expose us to greater risks than we normally assume, such as exposure to greater environmental or other liability and more onerous termination provisions giving the customer a right to terminate without cause or upon little or no notice. Upon termination, these contracts may not result in a payment to us, or if a termination payment is required, it may not fully compensate us for the loss of a contract.

Changes in tax laws, effective income tax rates or adverse outcomes resulting from examination of our tax returns could adversely affect our financial results.

Tax laws and regulations are highly complex and subject to interpretation and disputes. We conduct our worldwide operations through various subsidiaries in a number of countries throughout the world. As a result, we are subject to highly complex tax laws, regulations and income tax treaties within and between the countries in which we operate as well as countries in which we may be resident, which may change and are subject to interpretation. We determine our income tax expense based on our interpretation of the applicable tax laws and regulations in effect in each jurisdiction for the period during which we operate and earn income. Our overall effective tax rate could be adversely and suddenly affected by lower than anticipated earnings in countries where we have lower statutory rates and higher than anticipated earnings in countries where we have higher statutory rates, by changes in the valuation of our deferred tax assets and liabilities or by changes in tax law, tax treaties, regulations, accounting principles or interpretations thereof in one or more countries in which we operate. In addition, changes in laws, treaties and regulations and the interpretation of such laws, treaties and regulations may put us at risk for future tax assessments and liabilities which could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows.

Our income tax returns are subject to review and examination. We do not recognize the benefit of income tax positions we believe are more likely than not to be disallowed upon challenge by a tax authority. If any tax authority successfully challenges any tax position taken or intercompany pricing policies, or if the terms of certain income tax treaties are interpreted in a manner that is adverse to us or our operations, or if we lose a material tax dispute in any country, our effective tax rate on our worldwide earnings could increase substantially and our earnings and cash flows from operations could be materially adversely affected.

We are subject to extensive domestic and international laws and regulations that could significantly limit our business activities and revenues and increase our costs.

Our operations are affected in varying degrees by governmental laws and regulations. In addition to the specific regulatory risks discussed elsewhere in this Item 1A. “Risk Factors” section, our operations are subject to other laws, regulations and government policies worldwide. Certain countries are subject to restrictions, sanctions and embargoes imposed by the United States government or other governmental or international authorities. These restrictions, sanctions and embargoes may prohibit or limit us from participating in certain business activities in those countries. Our operations are also subject to numerous local, state and federal laws and regulations in the United States and in foreign jurisdictions concerning the containment and disposal of hazardous materials, the remediation of contaminated properties and the protection of the environment. The offshore drilling industry is dependent on demand for services from the oil and gas exploration industry and, accordingly, can be affected by changes in tax and other laws relating to the energy business generally. We may be required to make significant expenditures for additional capital equipment or inspections and recertifications thereof to comply with existing or new governmental laws and regulations. It is also possible that these laws and regulations may in the future add significantly to our operating costs or result in a reduction in revenues associated with downtime required to install such equipment or may otherwise significantly limit drilling activity.

In addition, our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a special survey, that are due every five years for most of our rigs. The inspection interval for our North Sea rigs is two-and-one-half years. These special surveys are generally performed in a shipyard and require scheduled downtime, which can negatively impact operating revenue. Operating expenses increase as a result of these special surveys due to the cost to mobilize the rigs to a shipyard, and inspection, repair and maintenance costs. Repair and maintenance activities may result from the special survey or may have been previously planned to take place during this mandatory downtime. The number of rigs undergoing a special survey will vary from year to year, as well as from quarter to quarter. Operating income may also be negatively impacted by intermediate surveys, which are performed at interim periods between special surveys. Although an intermediate survey normally does not require shipyard time, the survey may require some downtime for the rig. We can provide no assurance as to the exact timing and/or duration of downtime associated with regulatory inspections, planned rig mobilizations and other shipyard projects.

In April 2016, the Bureau of Safety and Environmental Enforcement, or BSEE, issued its final well control regulations in response to the 2010 Macondo well blowout and subsequent investigation into the causes of the event. The final well control rule, which became effective in July 2016, resulted in reforms that consolidated new regulations regarding equipment and operational requirements pertaining to offshore oil and gas drilling, completions, workovers and decommissioning operations in the U.S. Gulf of Mexico to enhance safety and environmental protection. BSEE’s final rule focuses on blowout preventers, or BOPs, and well-control requirements. Key features of the well control rule include requirements for BOPs, double shear rams, third-party reviews of equipment, real-time monitoring data, safe drilling margins, centralizers, inspections and other reforms related to well design and control, casing, cementing and subsea containment.

BSEE’s new regulations under the well control rule, to be phased in over time, could require modifications or enhancements to existing systems and equipment, or require new equipment, and could increase our operating costs and cause downtime for our rigs if we are required to take any of them out of service between scheduled surveys or inspections, or if we are required to extend scheduled surveys or inspections, to meet any such new requirements. We are not able to predict the likelihood, nature or extent of any additional rulemaking or the future impact of these events on our operations. Additional governmental regulations concerning licensing, taxation, equipment specifications, training requirements or other matters could increase the costs of our operations, and enhanced permitting requirements, as well as escalating costs borne by our customers, could reduce exploration activity in the GOM and therefore demand for our services.

Governments in some countries are increasingly active in regulating and controlling the ownership of concessions, the exploration for oil and gas and other aspects of the oil and gas industry. The modification of existing laws or regulations or the adoption of new laws or regulations curtailing exploratory or developmental drilling for oil and gas for economic, environmental or other reasons could materially and adversely affect our operations by limiting drilling opportunities.

Governments around the world are also increasingly considering and adopting laws and regulations to address climate change issues. Lawmakers and regulators in the United States and other jurisdictions where we operate have focused increasingly on restricting the emission of carbon dioxide, methane and other “greenhouse” gases. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. We may be exposed to risks related to new laws, regulations, treaties or international agreements pertaining to climate change, greenhouse gases, carbon emissions or energy use that could decrease the use of oil or natural gas, thus reducing demand for hydrocarbon-based fuel and our drilling services. Governments may also pass laws or regulations incentivizing or mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and natural gas and our drilling services. Such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business, and could adversely affect our operations by limiting drilling opportunities.

If we or our customers are unable to acquire or renew permits and approvals required for drilling operations, we may be forced to delay, suspend or cease our operations.

Oil and natural gas exploration and production operations require numerous permits and approvals for us and our customers from governmental agencies in the areas in which we operate or expect to operate. Obtaining all necessary permits and approvals may necessitate substantial expenditures to comply with the requirements of these permits and approvals, future changes to these permits or approvals, or any adverse change in the interpretation of existing permits and approvals. In addition, such regulatory requirements and restrictions could also delay or curtail our operations. Failure by us or our customers to obtain necessary permits and approvals in a timely manner could materially and adversely affect our financial condition, results of operations and cash flows.

Contracts for our drilling rigs are generally fixed dayrate contracts, and increases in our operating costs could adversely affect our profitability on those contracts.

Our contracts for our drilling rigs generally provide for the payment of a fixed dayrate per rig operating day, although some contracts do provide for a limited escalation in dayrate due to increased operating costs we incur on the project. Many of our operating costs, such as labor costs, are unpredictable and may fluctuate based on events beyond our control. In addition, equipment repair and maintenance expenses vary depending on the type of activity the rig is performing, the age and condition of the equipment and general market factors impacting relevant parts, components and services. The gross margin that we realize on these fixed dayrate contracts will fluctuate based on variations in our operating costs over the terms of the contracts. In addition, for contracts with dayrate escalation clauses, we may not be able to fully recover increased or unforeseen costs from our customers. Our inability to recover these increased or unforeseen costs from our customers could materially and adversely affect our financial condition, results of operations and cash flows.

Our business involves numerous operating hazards that could expose us to significant losses and significant damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us.

Our operations are subject to the significant hazards inherent in drilling for oil and gas offshore, such as blowouts, reservoir damage, loss of production, loss of well control, unstable or faulty sea floor conditions, fires and natural disasters such as hurricanes. The occurrence of any of these types of events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death to rig personnel and damage to producing or potentially productive oil and gas formations, oil spillage, oil leaks, well blowouts and extensive uncontrolled fires, any of which could cause significant environmental damage. In addition, offshore drilling operations are subject to marine hazards, including capsizing, grounding, collision and loss or damage from severe weather. Operations also may be suspended because of machinery breakdowns, abnormal drilling conditions, failure of suppliers or subcontractors to perform or supply goods or services or personnel shortages. Any of the foregoing events could result in significant damage or loss to our properties and assets or the properties and assets of others, injury or death to rig personnel or others, significant loss of revenues and significant damage claims against us, which could have a material adverse effect on our results of operations, financial condition and cash flows.

Our drilling contracts with our customers provide for varying levels of indemnity and allocation of liabilities between our customers and us with respect to the hazards and risks inherent in, and damages or losses arising out of, our operations, and we may not be fully protected. Our contracts with our customers generally provide that we and our customers each assume liability for our respective personnel and property. Our contracts also generally provide that our customers assume most of the responsibility for and indemnify us against loss, damage or other liability resulting from, among other hazards and risks, pollution originating from the well and subsurface damage or loss, while we typically retain responsibility for and indemnify our customers against pollution originating from the rig. However, in certain drilling contracts we may not be fully indemnified by our customers for damage to their property and/or the property of their other contractors. In certain contracts we may assume liability for losses or damages (including punitive damages) resulting from pollution or contamination caused by negligent or willful acts of commission or omission by us, our suppliers and/or subcontractors, generally (but not always) subject to negotiated caps on a per occurrence basis and/or on an aggregate basis for the term of the contract. In some cases, suppliers or subcontractors who provide equipment or services to us may seek to limit their liability resulting from pollution or contamination. Our contracts are individually negotiated, and the levels of indemnity and allocation of liabilities in them can vary from contract to contract depending on market conditions, particular customer requirements and other factors existing at the time a contract is negotiated. If we incur liability for significant losses or damages under any such provisions, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Additionally, the enforceability of indemnification provisions in our contracts may be limited or prohibited by applicable law or such provisions may not be enforced by courts having jurisdiction, and we could be held liable for substantial losses or damages and for fines and penalties imposed by regulatory authorities. The indemnification provisions in our contracts may be subject to differing interpretations, and the laws or courts of certain jurisdictions may enforce such provisions while other laws or courts may find them to be unenforceable, void or limited by public policy considerations, including when the cause of the underlying loss or damage is our gross negligence or willful misconduct, when punitive damages are attributable to us or when fines or penalties are imposed directly against us. The law with respect to the enforceability of indemnities varies from jurisdiction to jurisdiction and is unsettled under certain laws that are applicable to our contracts. Current or future litigation in particular jurisdictions, whether or not we are a party, may impact the interpretation and enforceability of indemnification provisions in our contracts. There can be no assurance that our contracts with our customers, suppliers and subcontractors will fully protect us against all hazards and risks inherent in our operations. There can also be no assurance that those parties with contractual obligations to indemnify us will be financially able to do so or will otherwise honor their contractual obligations.

We maintain liability insurance, which includes coverage for environmental damage; however, because of contractual provisions and policy limits, our insurance coverage may not adequately cover our losses and claim costs. In addition, certain risks such as pollution, reservoir damage and environmental risks are generally not fully insurable. Also, we do not typically purchase loss-of-hire insurance to cover lost revenues when a rig is unable to work.

We believe that the policy limit under our marine liability insurance is within the range that is customary for companies of our size in the offshore drilling industry and is appropriate for our business. However, if an accident or other event occurs that exceeds our coverage limits or is not an insurable event under our insurance policies, or is not fully covered by contractual indemnity, it could result in a significant loss to us. There can be no assurance that we will continue to carry the insurance we currently maintain, that our insurance will cover all types of losses or that we will be able to maintain adequate insurance in the future at rates we consider to be reasonable or that we will be able to obtain insurance against some risks.

Accordingly, the occurrence of any of these hazards or risks that we face could have a material adverse effect on our results of operations, financial condition and cash flows.

Significant portions of our operations are conducted outside the United States and involve additional risks not associated with United States domestic operations.

Our operations outside the United States accounted for approximately 66%, 79% and 85% of our total consolidated revenues for 2016, 2015 and 2014, respectively, and include, or have included, operations in South America, Australia and Southeast Asia, Europe, East and West Africa, the Mediterranean and Mexico. Because we operate in various regions throughout the world, we are exposed to a variety of risks inherent in international operations, including risks of war, political disruption, civil disturbance, acts of terrorism, political corruption, possible economic and legal sanctions (such as possible restrictions against countries that the U.S. government may consider to be state sponsors of terrorism) and changes in global trade policies. We may not have insurance coverage for these risks, or we may not be able to obtain adequate insurance coverage for such events at reasonable rates. Our operations may become restricted, disrupted or prohibited in any country in which any of these risks occur. We are also subject to the following risks in connection with our international operations:

- political and economic instability;
- piracy, terrorism or other assaults on property or personnel;
- kidnapping of personnel;
- seizure, expropriation, nationalization, deprivation, malicious damage or other loss of possession or use of property or equipment;
- renegotiation or nullification of existing contracts;
- disputes and legal proceedings in international jurisdictions;
- changing social, political and economic conditions;
- enactment of additional or stricter U.S. government or international sanctions;
- imposition of wage and price controls, trade barriers, export controls or import-export quotas;
- restrictive foreign and domestic monetary policies;
- the inability to repatriate income or capital;
- difficulties in collecting accounts receivable and longer collection periods;
- fluctuations in currency exchange rates and restrictions on currency exchange;
- regulatory or financial requirements to comply with foreign bureaucratic actions;
- restriction or disruption of business activities;

- limitation of our access to markets for periods of time;
- travel limitations or operational problems caused by public health threats or changes in immigration policies;
- difficulties in supplying, repairing or replacing equipment or transporting personnel in remote locations;
- difficulties in obtaining visas or work permits for our employees on a timely basis; and
- changing taxation policies and confiscatory or discriminatory taxation.

We are also subject to the regulations of the U.S. Treasury Department's Office of Foreign Assets Control and other U.S. laws and regulations governing our international operations in addition to domestic and international anti-bribery laws and sanctions and other restrictions imposed by other governmental or international authorities. In addition, international contract drilling operations are subject to various laws and regulations in countries in which we operate, including laws and regulations relating to:

- the equipping and operation of drilling rigs;
- import-export quotas or other trade barriers;
- repatriation of foreign earnings or capital;
- oil and gas exploration and development;
- local content requirements;
- taxation of offshore earnings and earnings of expatriate personnel; and
- use and compensation of local employees and suppliers by foreign contractors.

Some foreign governments favor or effectively require the awarding of drilling contracts to local contractors, require use of a local agent or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These practices may adversely affect our ability to compete in those regions. It is difficult to predict what governmental regulations may be enacted in the future that could adversely affect the international offshore drilling industry. The actions of foreign governments may materially and adversely affect our ability to compete against local competitors.

In addition, the shipment of goods, including the movement of a drilling rig across international borders, subjects us to extensive trade laws and regulations. Our import activities are governed by unique customs laws and regulations that differ in each of the countries in which we operate and often impose record keeping and reporting obligations. The laws and regulations concerning import/export activity and record keeping and reporting requirements are complex and change frequently. These laws and regulations may be enacted, amended, enforced and/or interpreted in a manner adverse to our operations. Shipments can be delayed and denied export or entry for a variety of reasons, some of which may be outside of our control. Shipping delays or denials could cause unscheduled downtime for our rigs. Failure to comply with these laws and regulations could result in criminal and civil penalties, economic sanctions, seizure of shipments and/or the contractual withholding of monies owed to us, among other things.

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

In the United States and in many of the international locations in which we operate, laws and regulations controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment apply to some of our operations. For example, we, as an operator of mobile offshore drilling units in navigable United States waters and some offshore areas, may be liable for damages and costs incurred in connection with oil spills related to those operations. Laws and regulations protecting the environment have become increasingly stringent, and may in some cases impose “strict liability,” rendering a person liable for environmental damage without regard to negligence or fault on the part of that person. These laws and regulations may expose us to liability for the conduct of, or conditions caused by, others or for acts that were in compliance with all applicable laws at the time they were performed.

U.S. federal and state, foreign and international laws and regulations address oil spill prevention and control and impose a variety of obligations on us related to the prevention of oil spills and liability for damages resulting from such spills. Some of these laws and regulations have significantly expanded liability exposure across all segments of the oil and gas industry. For example, the United States Oil Pollution Act of 1990 imposes strict and, with limited exceptions, joint and several liability upon each responsible party for oil removal costs and a variety of public and private damages. Failure to comply with such laws and regulations could subject us to civil or criminal enforcement action, for which we may not receive contractual indemnification or have insurance coverage, and could result in the issuance of injunctions restricting some or all of our activities in the affected areas. In addition, legislative and regulatory developments may occur that could substantially increase our exposure to liabilities that might arise in connection with our operations.

The application of these laws and regulations or the adoption of new laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows.

We may be subject to litigation and disputes that could have a material adverse effect on us.

We are, from time to time, involved in litigation and disputes. These matters may include, among other things, contract disputes, personal injury claims, environmental claims or proceedings, asbestos and other toxic tort claims, employment and tax matters and other litigation that arises in the ordinary course of our business. Although we intend to defend these matters vigorously, we cannot predict with certainty the outcome or effect of any dispute, claim or other litigation matter, and there can be no assurance as to the ultimate outcome of any litigation. We may not have insurance for litigation or claims that may arise, or if we do have insurance coverage it may not be sufficient, insurers may not remain solvent, other claims may exhaust some or all of the insurance available to us or insurers may interpret our insurance policies such that they do not cover losses for which we make claims or may otherwise dispute claims made. Litigation may have a material adverse effect on us because of potential adverse outcomes, defense costs, the diversion of our management’s resources and other risk factors inherent in litigation or relating to the claims that may arise.

We self-insure for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico.

Because the amount of insurance coverage available to us is limited, and the cost for such coverage is substantial, we self-insure for physical damage to rigs and equipment caused by named windstorms in the GOM. This results in a higher risk of losses, which could be material, that are not covered by third party insurance contracts. If one or more named windstorms in the GOM cause significant damage to our rigs or equipment, it could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, certain of our shore-based facilities are located in geographic regions that are susceptible to damage or disruption from hurricanes and other weather events. Future hurricanes or similar natural disasters that impact our facilities, our personnel located at those facilities or our ongoing operations may negatively affect our financial position and operating results. These negative effects may include or result from reduced or lost sales and revenues; costs associated with interruption in operations and with resuming operations; reduced demand for our services from customers that were similarly affected by these events; lost market share; late deliveries; uninsured property losses; lack of or inadequate business interruption insurance; employee evacuations; and an inability to retain necessary staff.

Our consolidated effective income tax rate may vary substantially from one reporting period to another.

Our consolidated effective income tax rate is impacted by the mix between our domestic and international pre-tax earnings or losses, as well as the mix of the international tax jurisdictions in which we operate. We cannot provide any assurances as to what our consolidated effective income tax rate will be in the future due to, among other factors, uncertainty regarding the nature and extent of our business activities in any particular jurisdiction in the future and the tax laws of such jurisdictions, as well as potential changes in U.S. and foreign tax laws, regulations or treaties or the interpretation or enforcement thereof, changes in the administrative practices and precedents of tax authorities or any reclassification or other matter (such as changes in applicable accounting rules) that increases the amounts we have provided for income taxes or deferred tax assets and liabilities in our consolidated financial statements. This variability may cause our consolidated effective income tax rate to vary substantially from one reporting period to another. An increase in our consolidated effective income tax rate could result in a material adverse effect on our financial condition, results of operations and cash flows.

We may be required to accrue additional tax liability on certain of our foreign earnings.

Certain of our international rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or DFAC, a Cayman Islands subsidiary that we own. It is our intention to indefinitely reinvest future earnings of DFAC and its foreign subsidiaries to finance our foreign activities. We do not expect to provide for U.S. taxes on any future earnings generated by DFAC and its foreign subsidiaries, except to the extent that these earnings are immediately subjected to U.S. federal income tax. Should a future distribution be made from any unremitted earnings of this subsidiary, we may be required to record additional U.S. income taxes.

Fluctuations in exchange rates and nonconvertibility of currencies could result in losses to us.

Due to our international operations, certain of our monetary assets and liabilities, including tax-related liabilities, are denominated in a foreign currency. Fluctuations in currency exchange rates could increase or decrease the amount receivable or payable by us. We have experienced currency exchange losses where revenues are received and expenses are paid in nonconvertible currencies or where we do not effectively hedge an exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital.

Acts of terrorism and other political and military events could adversely affect the markets for our drilling services.

Terrorist attacks and the continued threat of terrorism in the U.S. and abroad, the continuation or escalation of existing armed hostilities or the outbreak of additional hostilities could lead to increased political, economic and financial market instability and a downturn in the economies of the U.S. and other countries. A lower level of economic activity could result in a decline in energy consumption or an increase in the volatility of energy prices, either of which could materially and adversely affect the market for our offshore drilling services, our dayrates or our utilization and, accordingly, our financial condition, results of operations and cash flows. While we take steps that we believe are appropriately designed to secure our energy assets, there is no assurance that we can completely secure these assets, completely protect them against a terrorist attack or other political and military events or obtain adequate insurance coverage for such events at reasonable rates.

Although we have paid cash dividends in the past, we did not pay any dividends in 2016 and we may not pay regular or special cash dividends in the future, and we can give no assurance as to the amount or timing of the payment of any future regular or special cash dividends.

We pay dividends at the discretion of our Board of Directors, or Board. Any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board's consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs and other factors that our Board considers relevant at that time. The Board's dividend policy may change from time to time, but there can be no assurance that we will declare any cash dividends at all or in any particular amounts. See "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Dividend Policy" in Item 5 of this report and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" in Item 7 of this report.

We rely on third-party suppliers, manufacturers and service providers to secure and service equipment, components and parts used in rig operations, conversions, upgrades and construction.

Our reliance on third-party suppliers, manufacturers and service providers to provide equipment and services exposes us to volatility in the quality, price and availability of such items. Certain components, parts and equipment that we use in our operations may be available only from a small number of suppliers, manufacturers or service providers. The failure of one or more third-party suppliers, manufacturers or service providers to provide equipment, components, parts or services, whether due to capacity constraints, production or delivery disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment, is beyond our control and could materially disrupt our operations or result in the delay, renegotiation or cancellation of drilling contracts, thereby causing a loss of contract drilling backlog and/or revenue to us, as well as an increase in operating costs and an increased risk of additional asset impairments.

Additionally, our suppliers, manufacturers and service providers could be negatively impacted by current industry conditions or global economic conditions. If certain of our suppliers, manufacturers or service providers were to experience significant cash flow issues, become insolvent or otherwise curtail or discontinue their business as a result of such conditions, it could result in a reduction or interruption in supplies, equipment or services available to us and/or a significant increase in the price of such supplies, equipment and services, which could adversely impact our results of operations and cash flows.

We must make substantial capital and operating expenditures to build, maintain, and upgrade our drilling fleet.

Our business is highly capital intensive and dependent on having sufficient cash flow and/or available sources of financing in order to fund our desired capital expenditure requirements. We can provide no assurance that we will have access to adequate or economical sources of capital to fund our capital expenditures.

Our debt levels may limit our liquidity and flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2016, we had outstanding approximately $104.2 million in borrowings under our revolving credit facility and $2.0 billion of senior notes, maturing at various times from 2019 through 2043. As of February 10, 2017, we had no borrowings outstanding under our revolving credit facility and $1.5 billion available to meet our short-term liquidity requirements. We may incur additional indebtedness in the future and borrow from time to time under our revolving credit facility to fund working capital or other needs, subject to compliance with its covenants.

Our ability to meet our debt service obligations is dependent upon our future performance, which is subject to general economic conditions, industry cycles and financial, business and other factors affecting our operations, many of which are beyond our control. High levels of indebtedness could have negative consequences to us, including:

- we may have difficulty satisfying our obligations with respect to our outstanding debt;
- we may have difficulty obtaining financing in the future for working capital, capital expenditures, acquisitions or other purposes;
- we may need to use a substantial portion of our available cash flow from operations to pay interest and principal on our debt, which would reduce the amount of money available to fund working capital requirements, capital expenditures, the payment of dividends and other general corporate or business activities;

- our vulnerability to the effects of general economic downturns, adverse industry conditions and adverse operating results could increase;
- our flexibility in planning for, or reacting to, changes in our business and in our industry in general could be limited;
- we may not have the ability to pursue business opportunities that become available to us;
- our amount of debt and the amount we must pay to service our debt obligations could place us at a competitive disadvantage compared to our competitors that have less debt;
- our customers may react adversely to our significant debt level and seek alternative service providers; and
- our failure to comply with the restrictive covenants in our debt instruments that, among other things, require us to maintain a specified ratio of our consolidated indebtedness to total capitalization and limit the ability of our subsidiaries to incur debt, could result in an event of default that, if not cured or waived, could have a material adverse effect on our business.

In addition, approximately $500.0 million of our long-term senior notes will mature over the next five years and will need to be paid or refinanced. We may not be able to refinance our maturing debt upon commercially reasonable terms, or at all, depending on numerous factors, including our financial condition and prospects at the time and the then current state of the bank and capital markets in the U.S. Further, our liquidity may be adversely affected if we are unable to replace our revolving credit facility upon acceptable terms when it matures.

In November 2016, S&P Global Ratings, or S&P, downgraded our corporate credit rating to BB+ from BBB, and, in January 2017, further downgraded our corporate credit rating to BB-; the outlook remains negative. Our current corporate credit rating by Moody's Investors Service is Ba2, with a stable outlook. These credit ratings are below investment grade and could raise the cost of financing. As a consequence, we may not be able to issue additional debt in amounts and/or with terms that we consider to be reasonable. One or more of these occurrences could limit our ability to pursue other business opportunities.

Our revolving credit facility bears interest at variable rates, based on our corporate credit rating and market interest rates. If market interest rates increase, our cost to borrow under our revolving credit facility may also increase. Favorable changes in our current credit ratings could lower the fees that we pay under our revolving credit facility; however, any further downgrade in our credit ratings would have no further impact on the applicable interest rate margins and fees under our revolving credit facility. An increase in interest rates would have an adverse effect on our results of operations and cash flows. Although we may employ hedging strategies such that a portion of the aggregate principal amount outstanding under this credit facility would effectively carry a fixed rate of interest, any hedging arrangement put in place may not offer complete protection from this risk.

Any significant cyber attack or other interruption in network security or the operation of critical computer systems could materially disrupt our operations and adversely affect our business.

Our business has become increasingly dependent upon information technologies, systems and networks to conduct day-to-day operations, and we are placing greater reliance on technology to help support our operations and increase efficiency in our business functions. We are dependent upon our information technology and infrastructure, including operational and financial computer systems, to process the data necessary to conduct almost all aspects of our business. Computer and other business facilities and systems could become unavailable or impaired from a variety of causes including, among others, storms and other natural disasters, terrorist attacks, utility outages, theft, design defects, human error or complications encountered as existing systems are maintained, repaired, replaced or upgraded. It has also been reported that known or unknown entities or groups have mounted so-called "cyber attacks" on businesses and other organizations solely to disable or disrupt computer systems, disrupt operations and, in some cases, steal data. A breach or failure of our computer systems or networks, or those of our customers, vendors or others with whom we do business, could materially disrupt our business operations and our customers' operations and could result in the alteration, loss, theft or corruption of data or unauthorized release of confidential, proprietary or sensitive data concerning our company, business activities, employees, customers or vendors. Any such breach or failure could have a material adverse effect on our operations, business or reputation.

We discovered a material weakness in our internal controls and are exposed to risks relating to the effectiveness of our internal controls that could adversely affect our financial reporting and harm our business.

After we had announced our preliminary earnings for the quarter and year ended December 31, 2016, we became aware that our liability for uncertain tax positions in certain foreign jurisdictions did not appropriately reflect changes in foreign exchange rates. Management concluded that this failure was a material weakness in our internal control over financial reporting as of December 31, 2016. For a description of the material weakness in our internal control over financial reporting identified at December 31, 2016, see "Controls and Procedures" in Item 9A of this report.

If the new controls are not appropriately designed to address this material weakness or if we are unsuccessful in implementing or following these new processes or the new controls do not operate effectively or we are otherwise unable to remediate this material weakness, it may result in untimely or inaccurate reporting of our financial condition or results of operations. Ineffective internal controls could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock, limit our ability to access the capital markets in the future and require us to incur additional costs to improve our internal control systems and procedures.

Failure to obtain and retain highly skilled personnel could hurt our operations.

We require highly skilled personnel to operate and provide technical services and support for our business. A well-trained, motivated and adequately-staffed work force has a positive impact on our ability to attract and retain business. As a result, our future success depends on our continuing ability to identify, hire, develop, motivate and retain skilled personnel for all areas of our organization. To the extent that demand for drilling services and/or the size of the active worldwide industry fleet increases, shortages of qualified personnel could arise, creating upward pressure on wages and difficulty in staffing and servicing our rigs, which could adversely affect our results of operations. Our continued ability to compete effectively depends on our ability to attract new employees and to retain and motivate our existing employees. Heightened competition for skilled personnel could materially and adversely impact our financial condition, results of operations and cash flows by limiting our operations and further increasing our costs.

Unionization efforts and labor regulations in some of the countries in which we operate could materially increase our costs or limit our flexibility.

Some of our employees in non-U.S. markets are represented by labor unions and work under collective bargaining or similar agreements which are subject to periodic renegotiation. These negotiations could result in higher personnel expenses, other increased costs or increased operational restrictions. Efforts have been made from time to time to unionize other portions of our workforce. In addition, we may be subjected to strikes or work stoppages and other labor disruptions in certain countries. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our flexibility.

The results of the United Kingdom's referendum on withdrawal from the European Union may have a negative effect on global economic conditions, financial markets and our business.

In June 2016, a majority of voters in the U.K. elected to withdraw from the European Union in a national referendum. The terms of any withdrawal are subject to a negotiation period that could last at least two years after the government of the U.K. formally initiates a withdrawal process. Nevertheless, the referendum has created significant uncertainty about the future relationship between the U.K. and the European Union, including with respect to the laws and regulations that will apply as the U.K. determines which European Union-derived laws to replace or replicate in the event of a withdrawal. The governments of other European Union member states may also consider withdrawal. These developments, or the perception that any of them could occur, may have an adverse effect on global economic conditions and the stability of global financial markets, and may significantly reduce global market liquidity and restrict the ability of key market participants to operate in certain financial markets. Any of these factors could depress economic activity and restrict our access to capital, which could have a material adverse effect on our business, financial condition and results of operations.

Rig conversions, upgrades or new-builds may be subject to delays and cost overruns.

From time to time, we add new capacity through conversions or upgrades to our existing rigs or through new construction. Projects of this type are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- work stoppages;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated cost increases or change orders;
- weather interferences or storm damage;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- disputes with shipyards or suppliers;
- availability of suppliers to recertify equipment for enhanced regulations;
- customer acceptance delays;
- shipyard failures or unavailability; and
- failure or delay of third party service providers, civil unrest and labor disputes.

Failure to complete a rig upgrade or new construction on time, or failure to complete a rig conversion or new construction in accordance with its design specifications may, in some circumstances, result in the delay, renegotiation or cancellation of a drilling contract, resulting in a loss of contract drilling backlog and revenue to us. If a drilling contract is terminated under these circumstances, we may not be able to secure a replacement contract or, if we do secure a replacement contract, it may not contain equally favorable terms. In addition, impairment write-offs could result if a rig's carrying value becomes excessive due to spending over budget on a newbuild construction project or major rig upgrade.

We are controlled by a single stockholder, which could result in potential conflicts of interest.

Loews Corporation, which we refer to as Loews, beneficially owned approximately 53% of our outstanding shares of common stock as of February 10, 2017, and is in a position to control actions that require the consent of stockholders, including the election of directors, amendment of our Restated Certificate of Incorporation and any merger or sale of substantially all of our assets. In addition, three officers of Loews serve on our Board of Directors. One of those, James S. Tisch, the Chairman of the Board of our company, is also the Chief Executive Officer and a director of Loews. We have also entered into a services agreement and a registration rights agreement with Loews, and we may in the future enter into other agreements with Loews.

Loews is a holding company. In addition to us, its principal subsidiaries are CNA Financial Corporation, a 90% owned subsidiary engaged in commercial property and casualty insurance; Boardwalk Pipeline Partners, LP, a 51% owned subsidiary engaged in transportation and storage of natural gas and natural gas liquids and gathering and processing of natural gas; and Loews Hotels Holding Corporation, a wholly-owned subsidiary engaged in the operation of a chain of hotels. It is possible that Loews may in some circumstances be in direct or indirect competition with us, including competition with respect to certain business strategies and transactions that we may propose to undertake. In addition, potential conflicts of interest exist or could arise in the future for our directors who are also officers of Loews with respect to a number of areas relating to the past and ongoing relationships of Loews and us, including tax and insurance matters, financial commitments and sales of common stock pursuant to registration rights or otherwise. Although the affected directors may abstain from voting on matters in which our interests and those of Loews are in conflict so as to avoid potential violations of their fiduciary duties to stockholders, the presence of potential or actual conflicts could affect the process or outcome of Board deliberations.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

We own an office building in Houston, Texas, where our corporate headquarters are located. We also own offices and other facilities in New Iberia, Louisiana, Aberdeen, Scotland, Macae, Brazil and Ciudad del Carmen, Mexico. Additionally, we currently lease various office, warehouse and storage facilities in Australia, Louisiana, Malaysia, Singapore, Trinidad and Tobago, and the U.K. to support our offshore drilling operations.

Item 3. Legal Proceedings.

See information with respect to legal proceedings in Note 12 “Commitments and Contingencies” to our Consolidated Financial Statements in Item 8 of this report.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Price Range of Common Stock

Our common stock is listed on the New York Stock Exchange, or NYSE, under the symbol "DO." The following table sets forth, for the calendar quarters indicated, the high and low closing prices of our common stock as reported by the NYSE.

	Common Stock	
	High	Low
2016		
First Quarter	$24.09	$15.55
Second Quarter	26.04	20.28
Third Quarter	26.11	14.80
Fourth Quarter	21.08	15.42
2015		
First Quarter	$37.23	$26.49
Second Quarter	34.81	25.81
Third Quarter	25.45	17.30
Fourth Quarter	23.50	16.81

As of February 10, 2017, there were approximately 154 holders of record of our common stock. This number represents registered stockholders and does not include stockholders who hold their shares through an institution.

Dividend Policy

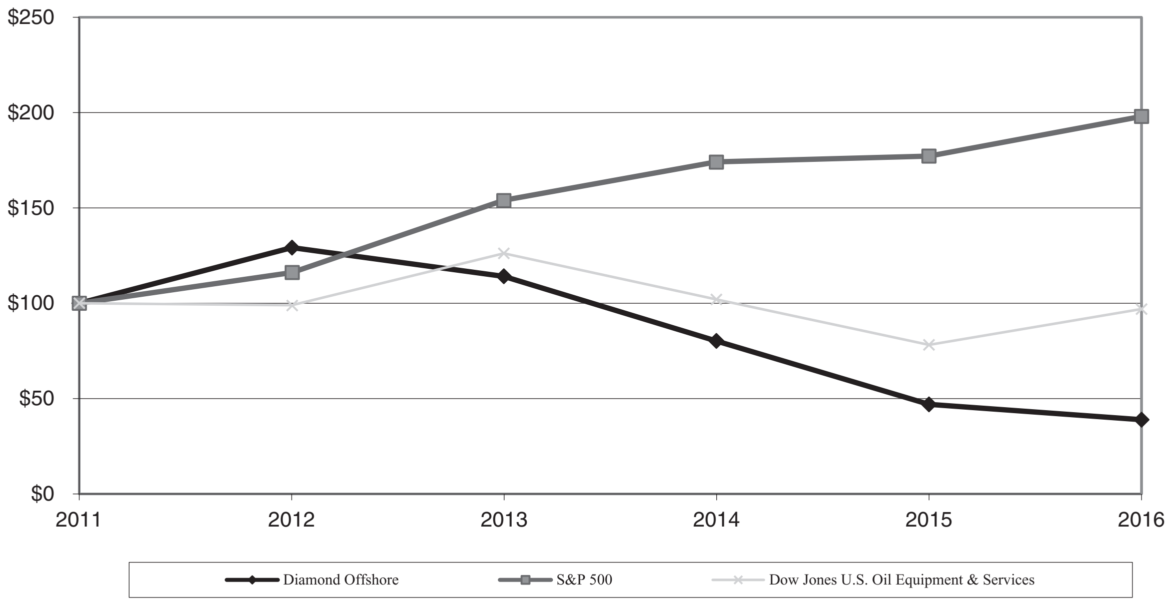
In 2016, we discontinued our regular cash dividend. In 2015, we paid regular cash dividends of $0.125 per share of our common stock on March 2, June 1, September 1 and December 1.

We pay dividends at the discretion of our Board of Directors. Any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board's consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs and other factors that our Board considers relevant at that time. The Board's dividend policy may change from time to time, but there can be no assurance that we will declare any cash dividends at all or in any particular amounts. See "Risk Factors — *Although we have paid cash dividends in the past, we did not pay any dividends in 2016 and we may not pay regular or special cash dividends in the future, and we can give no assurance as to the amount or timing of the payment of any future regular or special cash dividends*" in Item 1A of this report, which is incorporated herein by reference.

CUMULATIVE TOTAL STOCKHOLDER RETURN

The following graph shows the cumulative total stockholder return for our common stock, the Standard & Poor's 500 Composite Stock Index, or S&P 500 Index, and the Dow Jones U.S. Oil Equipment & Services index over the five year period ended December 31, 2016.

Comparison of Five-Year Cumulative Total Return (1)



	Dec. 31, 2011	Dec. 31, 2012	Dec. 31, 2013	Dec. 31, 2014	Dec. 31, 2015	Dec. 31, 2016
Diamond Offshore	100	129	114	80	47	39
S&P 500 Index	100	116	154	174	177	198
Dow Jones U.S. Oil Equipment & Services	100	99	126	102	78	97

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on December 31, 2011 in our common stock and the two published indices.

Our dividend history for the periods reported above is as follows:

	Q1		Q2		Q3		Q4	
Year	Regular	Special	Regular	Special	Regular	Special	Regular	Special
2016	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2015	$0.125	$ —	$0.125	$ —	$0.125	$ —	$0.125	$ —
2014	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75
2013	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75
2012	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75	$0.125	$0.75

Item 6. Selected Financial Data.

The following table sets forth certain historical consolidated financial data relating to Diamond Offshore. We prepared the selected consolidated financial data from our consolidated financial statements as of and for the periods presented. The selected consolidated financial data below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and our Consolidated Financial Statements (including the Notes thereto) in Item 8 of this report.

	As of and for the Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands, except per share and ratio data)				
Income Statement Data:					
Total revenues	$1,600,342	$2,419,393	$2,814,671	$2,920,421	$2,986,508
Operating (loss) income	(356,884) [1]	(294,074) [1]	572,562 [1]	801,606	962,378
Net (loss) income	(372,503)	(274,285)	387,011	548,686	720,477
Net (loss) income per share:					
Basic	(2.72)	(2.00)	2.82	3.95	5.18
Diluted	(2.72)	(2.00)	2.81	3.95	5.18
Balance Sheet Data:					
Drilling and other property and equipment, net	$5,726,935 [1]	$6,378,814 [1]	$6,945,953 [1]	$5,467,227	$4,864,972
Total assets	6,371,877	7,149,894 [2]	8,005,398 [2]	8,374,437 [2]	7,223,760 [2]
Long-term debt (excluding current maturities) [3]	1,980,884	1,979,778 [2]	1,978,635 [2]	2,227,192 [2]	1,484,540 [2]
Other Financial Data:					
Capital expenditures	$ 652,673	$ 830,655	$2,032,764 [4]	$ 957,598	$ 702,041
Cash dividends declared per share	—	0.50	3.50	3.50	3.50
Ratio of earnings to fixed charges [5]	(3.21)x [6]	(2.45)x [6]	4.64x	7.79x	11.11x

(1) During 2016, 2015 and 2014, we recorded impairment losses aggregating $678.1 million, $860.4 million and $109.5 million, respectively, to write down certain of our drilling rigs and related equipment with indicators of impairment to their estimated recoverable amounts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — *Years Ended December 31, 2016, 2015 and 2014 — Overview — 2016 Compared to 2015 — Impairment of Assets*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — *Years Ended December 31, 2016, 2015 and 2014 — Overview — 2015 Compared to 2014 — Impairment of Assets*" in Item 7 and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report for a discussion of these impairments.

(2) Historical data for the four annual periods ending on or before December 31, 2015 has been restated to reflect the effect thereon of the adoption on January 1, 2016 of an accounting standard which requires debt issuance costs associated with our senior notes to be presented in the balance sheet as a reduction in the related long-term debt. Prior to the adoption of this accounting standard, debt issuance costs associated with our senior notes were presented as "Prepaid expenses and other current assets" and "Other assets" in our Consolidated Balance Sheets. See Note 1 "General Information — Debt Issuance Costs" to our Consolidated Financial Statements in Item 8 of this report.

(3) See Note 10 "Credit Agreement, Commercial Paper and Senior Notes" to our Consolidated Financial Statements included in Item 8 of this report for a discussion of changes to our long-term debt.

(4) During 2014, we took delivery of three ultra-deepwater drillships and two deepwater semisubmersible rigs. The aggregate net book value of these newly constructed rigs was $2.7 billion at December 31, 2014, of which $1.3 billion was reported in construction work-in-progress at December 31, 2013. See Note 9 "Drilling and Other Property and Equipment" to our Consolidated Financial Statements in Item 8 of this report for a discussion of the components of our drilling and other property and equipment.

(5) For all periods presented, the ratio of earnings to fixed charges has been computed on a total enterprise basis. Earnings represent pre-tax income from continuing operations plus fixed charges. Fixed charges include (i) interest, whether expensed or capitalized, (ii) amortization of debt issuance costs, whether expensed or capitalized, and (iii) a portion of rent expense, which we believe represents the interest factor attributable to rent.

(6) The deficiency in our earnings available for fixed charges for the years ended December 31, 2016 and 2015 was $479.8 million and $388.9 million, respectively.

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

The following discussion should be read in conjunction with our Consolidated Financial Statements (including the Notes thereto) in Item 8 of this report.

We provide contract drilling services to the energy industry around the globe with a fleet of 24 offshore drilling rigs. Our current fleet consists of four drillships, 19 semisubmersible rigs, and one jack-up rig. Of our current fleet, as of January 30, 2017, ten rigs are cold stacked, consisting of four ultra-deepwater, three deepwater and three mid-water semisubmersible rigs. All previously held-for-sale rigs have been sold, except for the *OceanSpur*, which is expected to be sold in the near future. In December 2016, we placed the *Ocean GreatWhite* into service, completing our most recent equipment enhancement cycle. The *Ocean GreatWhite* is currently on standby in Labuan, Malaysia, pending further instructions from BP.

Market Overview

Oil prices, which had fallen to a 12-year low of less than $30 per barrel in January 2016, rebounded to some extent into the low-to-mid-$50s per barrel range by the end of January 2017, in part due to expectations that an agreement to cut production by certain members of the Organization of Petroleum Exporting Countries, or OPEC, and others that went into effect in 2017 would reduce the oversupply of oil and raise and potentially stabilize oil prices. To date, however, oil prices have continued to exhibit volatility due to multiple factors, including fluctuations in the current and expected level of global oil inventories and estimates of global demand. Despite the recent rise in oil prices and announcements by a few customers of planned increases in capital spending in 2017, we expect that overall capital spending for offshore exploration and development in 2017 will be lower than 2016 levels. As a consequence, the offshore contract drilling industry remains weak.

Industry analysts have reported that in 2016, for the second consecutive year, the global supply of floater rigs decreased with 24 floaters being scrapped during the year. In addition, many drilling rigs across all water depth categories were cold stacked in 2016. Despite these events, the oversupply of drilling rigs in the floater markets continues to persist. Industry reports indicate that only three newbuild floaters were delivered in 2016; however, there are approximately 40 newbuild floaters scheduled for delivery between 2017 and 2021. Industry analysts predict that these delivery dates may extend further as newbuild owners negotiate with their respective shipyards.

Given the oversupply of rigs, competition for the limited number of offshore drilling jobs continues to be intense. In some cases, dayrates have been negotiated at break-even or below-cost levels in order to enable the drilling contractor to recover a portion of operating costs for rigs that would otherwise be uncontracted or cold stacked. In addition, customers have indicated a preference for "hot" rigs rather than reactivated cold-stacked rigs. This preference incentivizes the drilling contractor to contract rigs at lower rates for the sole purpose of maintaining the rigs in an active state and allowing for at least partial cost recovery. Industry analysts have predicted that the offshore contract drilling market will remain depressed through 2017.

As a result of the continuing depressed market conditions in the offshore drilling industry and continued pessimistic outlook for the near term, certain of our customers, as well as those of our competitors, have attempted to renegotiate or terminate existing drilling contracts. Such renegotiations have included requests to lower the contract dayrate in some cases in exchange for additional contract term, shorten the term on one contracted rig in exchange for additional term on another rig, to early terminate a contract in exchange for a lump sum payout and many other possibilities. In addition to the potential for renegotiations, some of our drilling contracts permit the customer to terminate the contract early after specified notice periods, usually resulting in a requirement for the customer to pay a contractually specified termination amount, which may not fully compensate us for the loss of the contract. As a result of these depressed market conditions, some customers have also utilized such contract clauses to seek to renegotiate or terminate a drilling contract or claim that we have breached provisions of our drilling contracts in order to avoid their obligations to us under circumstances where we believe we are in compliance with the contracts. See "Risk Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized.*"

Particularly during depressed market conditions, the early termination of a contract may result in a rig being idle for an extended period of time, which could adversely affect our financial condition, results of operations and cash flows. When a customer terminates our contract prior to the contract's scheduled expiration, our contract backlog is also adversely impacted.

Our results of operations and cash flows for the years ended December 31, 2016 and 2015 have been materially impacted by depressed market conditions in the offshore drilling industry. We currently expect that these adverse market conditions will continue for the foreseeable future. The continuation of these conditions for an extended period could result in more of our rigs being without contracts and/or cold stacked or scrapped and could further materially and adversely affect our financial condition, results of operations and cash flows. When we cold stack or elect to scrap a rig, we evaluate the rig for impairment. During 2016, we recognized an aggregate impairment loss of $678.1 million, related to eight of our drilling rigs and related spare parts and supplies. During 2015, we recognized an aggregate impairment loss of $860.4 million related to 17 of our drilling rigs. See "— Results of Operations — *Overview — 2016 Compared to 2015 — Impairment of Assets,*" "Risk Factors — *We may incur additional asset impairments and/or rig retirements as a result of reduced demand for certain offshore drilling rigs*" in Item 1A of this report and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Historically, the longer a drilling rig remains cold stacked, the higher the cost of reactivation and, depending on the age, technological obsolescence and condition of the rig, the lower the likelihood that the rig will be reactivated at a future date. As of January 30, 2017, ten rigs in our fleet were cold stacked.

See "— Contract Drilling Backlog*"* for future commitments of our rigs during 2017 through 2020.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of January 1, 2017 (based on contract information known at that time), October 1, 2016 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016), and February 16, 2016 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2015). Contract drilling backlog as presented below includes only firm commitments (typically represented by signed contracts) and is calculated by multiplying the contracted operating dayrate by the firm contract period. Our calculation also assumes full utilization of our drilling equipment for the contract period (excluding scheduled shipyard and survey days); however, the amount of actual revenue earned and the actual periods during which revenues are earned will be different than the amounts and periods shown in the tables below due to various factors. Utilization rates, which generally approach 92-98% during contracted periods, can be adversely impacted by downtime due to various operating factors including, but not limited to, weather conditions and unscheduled repairs and maintenance. Contract drilling backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. No revenue is generally earned during periods of downtime for regulatory surveys. Changes in our contract drilling backlog between periods are generally a function of the performance of work on term contracts, as well as the extension or modification of existing term contracts and the execution of additional contracts. In addition, under certain circumstances, our customers may seek to terminate or renegotiate our contracts, which could adversely affect our reported backlog. See "Risk Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized*" in Item 1A of this report, which is incorporated herein by reference.

	January 1, 2017	October 1, 2016	February 16, 2016
		(In thousands)	
Contract Drilling Backlog			
Ultra-Deepwater Floaters [(1)]	$3,215,000	$3,614,000	$4,415,000
Deepwater Floaters	197,000	258,000	375,000
Other Rigs [(2)]	152,000	210,000	405,000
Total	$3,564,000	$4,082,000	$5,195,000

(1) Contract drilling backlog as of January 1, 2017 for our ultra-deepwater floaters includes (i) $470.9 million from 2017 to 2020 attributable to the *Ocean GreatWhite*, which reflects a revised standby rate that allows us to pass along certain cost savings to our customer while maintaining approximately the same operating margin and cash flows of the original contract, and (ii) $268.6 million from 2017 to 2018 attributable to contracted work for the *Ocean Valor* under the contract that Petróleo Brasiliero S.A., or Petrobras, has attempted to terminate and is currently in effect pursuant to an injunction granted by a Brazilian court, which Petrobras has appealed.

(2) Includes contract drilling backlog for our mid-water floaters and jack-up rig.

The following table reflects the amount of our contract drilling backlog by year as of January 1, 2017.

	Total	For the Years Ending December 31, 2017	2018	2019	2020
	(In thousands)				
Contract Drilling Backlog					
Ultra-Deepwater Floaters [(1)]	$3,215,000	$1,132,000	$1,073,000	$842,000	$168,000
Deepwater Floaters	197,000	186,000	11,000	—	—
Other Rigs [(2)]	152,000	152,000	—	—	—
Total	$3,564,000	$1,470,000	$1,084,000	$842,000	$168,000

(1) Contract drilling backlog as of January 1, 2017 for our ultra-deepwater floaters includes (i) $158.2 million, $157.5 million, $149.5 million and $5.7 million for the years 2017, 2018, 2019 and 2020, respectively, attributable to the *Ocean GreatWhite*, which reflects a revised standby rate that allows us to pass along certain cost savings to our customer while maintaining approximately the same operating margin and cash flows of the original contract, and (ii) $149.4 million and $119.2 million for the years 2017 and 2018, respectively, attributable to contracted work for the *Ocean Valor* under the contract that Petrobras has attempted to terminate and is currently in effect pursuant to an injunction granted by a Brazilian court, which Petrobras has appealed.

(2) Includes contract drilling backlog for our mid-water floaters and jack-up rig.

The following table reflects the percentage of rig days committed by year as of January 1, 2017. The percentage of rig days committed is calculated as the ratio of total days committed under contracts, as well as scheduled shipyard, survey and mobilization days for all rigs in our fleet, to total available days (number of rigs multiplied by the number of days in a particular year).

	For the Years Ending December 31, 2017	2018	2019	2020
Rig Days Committed [(1)]				
Ultra-Deepwater Floaters	64%	57%	45%	9%
Deepwater Floaters	39%	3%	—	—
Other Rigs [(2)]	23%	—	—	—

(1) As of January 1, 2017, includes approximately 135 currently known, scheduled shipyard days for contract preparation, surveys and extended maintenance projects, as well as mobilization days, for the year 2017.

(2) Includes contract drilling backlog for our mid-water floater and jack-up rig.

Important Factors That May Impact Our Operating Results, Financial Condition or Cash Flows

Operating Income. Our operating income is primarily a function of contract drilling revenue earned less contract drilling expenses incurred or recognized. The two most significant variables affecting our contract drilling revenue are the dayrates earned and utilization rates achieved by our rigs, each of which is a function of rig supply and demand in the marketplace. These factors are not entirely within our control and are difficult to predict. We generally recognize revenue from dayrate drilling contracts as services are performed. Consequently, when a rig is idle, no dayrate is earned and revenue will decrease as a result.

Revenue is also affected by the acquisition or disposal of rigs, rig mobilizations, required surveys and shipyard projects. In connection with certain drilling contracts, we may receive fees for the mobilization of equipment. In addition, some of our drilling contracts require downtime before the start of the contract to prepare the rig to meet customer requirements for which we may or may not be compensated. We earn these fees as services are performed over the initial term of the related drilling contracts. We defer mobilization and contract preparation fees received (on either a lump-sum or dayrate basis), as well as direct and incremental costs associated with the mobilization of equipment and contract preparation activities, and amortize each, on a straight-line basis, over the term of the related drilling contracts. Absent a contract, mobilization costs are recognized currently.

Operating income also fluctuates due to varying levels of contract drilling expenses. Our operating expenses represent all direct and indirect costs associated with the operation and maintenance of our drilling equipment, which generally are not affected by changes in dayrates and short-term reductions in utilization. For instance, if a rig is to be idle for a short period of time, few decreases in operating expenses may actually occur since the rig is typically maintained in a prepared or "warm-stacked" state with a full crew. In addition, when a rig is idle, we are responsible for certain operating expenses such as rig fuel and supply boat costs, which are typically costs of the operator when a rig is under contract. However, if a rig is expected to be idle for an extended period of time, we may reduce the size of a rig's crew and take steps to "cold stack" the rig, which lowers expenses and partially offsets the impact on operating income. The cost of cold stacking a rig can vary depending on the type of rig. The cost of cold stacking a drillship, for example, is typically substantially higher than the cost of cold stacking a jack-up rig or an older floater rig.

The principal components of our operating costs are, among other things, direct and indirect costs of labor and benefits, repairs and maintenance, freight, regulatory inspections, boat and helicopter rentals and insurance. Labor and repair and maintenance costs represent the most significant components of our operating expenses. In general, our labor costs increase primarily due to higher salary levels, rig staffing requirements and costs associated with labor regulations in the geographic regions in which our rigs operate. In addition, the costs associated with training employees can be significant. Costs to repair and maintain our equipment fluctuate depending upon the type of activity the drilling unit is performing, as well as the age and condition of the equipment and the regions in which our rigs are working. See "— Contractual Cash Obligations — *Pressure Control by the Hour*."

Regulatory Surveys and Planned Downtime. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a special survey, that are due every five years for most of our rigs. The inspection interval for our North Sea rigs is two-and-one-half years. Operating revenue decreases because these special surveys are generally performed during scheduled downtime in a shipyard. Operating expenses increase as a result of these special surveys due to the cost to mobilize the rigs to a shipyard, inspection costs incurred and repair and maintenance costs, which are recognized as incurred. Repair and maintenance activities may result from the special survey or may have been previously planned to take place during this mandatory downtime. The number of rigs undergoing a special survey will vary from year to year, as well as from quarter to quarter.

During 2017, we expect to spend approximately 135 days for a special survey and contract modifications for the *Ocean Monarch*, as well as the related mobilization of the rig, and 65 days for a special survey for the *Ocean Patriot* scheduled after completion of its current contract. We can provide no assurance as to the exact timing and/or duration of downtime associated with regulatory inspections, planned rig mobilizations and other shipyard projects. See "— *Contract Drilling Backlog.*"

Physical Damage and Marine Liability Insurance. We are self-insured for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico, as defined by the relevant insurance policy. If a named windstorm in the U.S. Gulf of Mexico causes significant damage to our rigs or equipment, it could have a material adverse effect on our financial condition, results of operations and cash flows. Under our current insurance policy, which renewed effective May 1, 2016, we carry physical damage insurance for certain losses other than those caused by named windstorms in the U.S. Gulf of Mexico for which our deductible for physical damage is $25.0 million per occurrence. We do not typically retain loss-of-hire insurance policies to cover our rigs.

In addition, under our current insurance policy, which renewed effective May 1, 2016, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, and generally covering liabilities arising out of or relating to pollution and/or environmental risk. We believe that the policy limit for our marine liability insurance is within the range that is customary for companies of our size in the offshore drilling industry and is appropriate for our business. Our deductibles for marine liability coverage related to insurable events arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for other marine liability coverage, including personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, are $10.0 million for the first occurrence and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

Construction and Capital Upgrade Projects. We capitalize interest cost for the construction and upgrade of qualifying assets in accordance with accounting principles generally accepted in the U.S., or GAAP. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use, and the capitalization period ends when the asset is substantially complete and ready for its intended use. For the year ended December 31, 2016, we capitalized interest of $20.8 million on qualifying expenditures related to the construction of the *Ocean GreatWhite* until it was placed in service in December 2016. At December 31, 2016, we had no ongoing construction projects that qualified for interest capitalization. Accordingly, we expect interest expense to increase in 2017, compared to previous years.

Impact of Changes in Tax Laws or Their Interpretation. We operate through our various subsidiaries in a number of countries throughout the world. As a result, we are subject to highly complex tax laws, treaties and regulations in the jurisdictions in which we operate, which may change and are subject to interpretation. Changes in laws, treaties and regulations and the interpretation of such laws, treaties and regulations may put us at risk for future tax assessments and liabilities which could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows.

Critical Accounting Estimates

Our significant accounting policies are included in Note 1 “General Information” to our Consolidated Financial Statements in Item 8 of this report. Judgments, assumptions and estimates by our management are inherent in the preparation of our financial statements and the application of our significant accounting policies. We believe that our most critical accounting estimates are as follows:

Property, Plant and Equipment. We carry our drilling and other property and equipment at cost, less accumulated depreciation. Maintenance and routine repairs are charged to income currently while replacements and betterments that upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset, are capitalized. Significant judgments, assumptions and estimates may be required in determining whether or not such replacements and betterments meet the criteria for capitalization and in determining useful lives and salvage values of such assets. Changes in these judgments, assumptions and estimates could produce results that differ from those reported. Historically, the amount of capital additions requiring significant judgments, assumptions or estimates has not been significant. During the years ended December 31, 2016 and 2015, we capitalized $177.6 million and $262.4 million, respectively, in replacements and betterments of our drilling fleet.

We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable (such as, but not limited to, cold stacking a rig, the expectation of cold stacking a rig in the near term, contracted backlog of less than one year for a rig, a decision to retire or scrap a rig, or excess spending over budget on a newbuild, construction project or major rig upgrade). We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment. Our assumptions and estimates underlying this analysis include the following:

- dayrate by rig;
- utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);
- the per day operating cost for each rig if active, warm stacked or cold stacked;
- the estimated annual cost for rig replacements and/or enhancement programs;
- the estimated maintenance, inspection or other reactivation costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of each rig.

Based on these assumptions, we develop a matrix for each rig under evaluation using multiple utilization/dayrate scenarios, to each of which we have assigned a probability of occurrence. We arrive at a projected probability-weighted cash flow for each rig based on the respective matrix and compare such amount to the carrying value of the asset to assess recoverability.

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig's age, rated water depth and other attributes and then assesses its future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance, inspection and reactivation costs, are estimated using historical data adjusted for known developments, cost projections for re-entry of rigs into the market and future events that are anticipated by management at the time of the assessment.

Management's assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation, and the use of different assumptions could produce results that differ from those reported. Our methodology generally involves the use of significant unobservable inputs, representative of a Level 3 fair value measurement, which may include assumptions related to future dayrate revenue, costs and rig utilization, quotes from rig brokers, the long-term future performance of our rigs and future market conditions. Management's assumptions involve uncertainties about future demand for our services, dayrates, expenses and other future events, and management's expectations may not be indicative of future outcomes. Significant unanticipated changes to these assumptions could materially alter our analysis in testing an asset for potential impairment. For example, changes in market conditions that exist at the measurement date or that are projected by management could affect our key assumptions. Other events or circumstances that could affect our assumptions may include, but are not limited to, a further sustained decline in oil and gas prices, cancelations of our drilling contracts or contracts of our competitors, contract modifications, costs to comply with new governmental regulations, capital expenditures required due to advances in offshore drilling technology, growth in the global oversupply of oil and geopolitical events, such as lifting sanctions on oil-producing nations. Should actual market conditions in the future vary significantly from market conditions used in our projections, our assessment of impairment would likely be different.

During 2016, we evaluated 15 of our drilling rigs with indications that their carrying amounts may not be recoverable. Based on our assumptions and analyses, we determined that the carrying values of eight drilling rigs were impaired, including one rig that had previously been impaired in a prior year. In the second quarter of 2016, we recorded an aggregate impairment loss of $678.1 million, which included an $8.1 million impairment of rig spares and supplies. During 2015, we evaluated 25 of our drilling rigs with indications that their carrying amounts may not be recoverable and recorded an aggregate impairment loss of $860.4 million related to 17 drilling rigs. During 2014, we recognized an impairment loss of $109.5 million in connection with our management's decision to retire and scrap six mid-water semisubmersible rigs. See "— Results of Operations — *Overview — 2016 Compared to 2015 — Impairment of Assets*" and "— Results of Operations — *Overview — 2015 Compared to 2014 — Impairment of Assets*" in Item 7 and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Personal Injury Claims. Under our current insurance policies, which renewed effective May 1, 2016, our deductibles for marine liability insurance coverage with respect to personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, which primarily result from Jones Act liability in the Gulf of Mexico, are $10.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductible for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. The Jones Act is a federal law that permits seamen to seek compensation for certain injuries during the course of their employment on a vessel and governs the liability of vessel operators and marine employers for the work-related injury or death of an employee. We engage outside consultants to assist us in estimating our aggregate liability for personal injury claims based on our historical losses and utilizing various actuarial models.

The models used in estimating our aggregate reserve for personal injury claims include actuarial assumptions such as:

- claim emergence, or the delay between occurrence and recording of claims;
- settlement patterns, or the rates at which claims are closed;
- development patterns, or the rate at which known cases develop to their ultimate level;
- average, potential frequency and severity of claims; and
- effect of re-opened claims.

The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

- the severity of personal injuries claimed;
- significant changes in the volume of personal injury claims;
- the unpredictability of legal jurisdictions where the claims will ultimately be litigated;
- inconsistent court decisions; and
- the risks and lack of predictability inherent in personal injury litigation.

Income Taxes. We account for income taxes in accordance with accounting standards that require the recognition of the amount of taxes payable or refundable for the current year and 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 currently recognized in our financial statements or tax returns. In each of our tax jurisdictions we recognize a current tax liability or asset for the estimated taxes payable or refundable on tax returns for the current year and a deferred tax asset or liability for the estimated future tax effects attributable to temporary differences and carryforwards. Deferred tax assets are reduced by a valuation allowance, if necessary, which is determined by the amount of any tax benefits that, based on available evidence, are not expected to be realized under a "more likely than not" approach. We do not establish deferred tax liabilities for certain of our foreign earnings that we intend to indefinitely reinvest to finance foreign activities. However, if these earnings become subject to U.S. federal tax, any required provision could have a material adverse impact on our financial results. We make judgments regarding future events and related estimates especially as they pertain to the forecasting of our effective tax rate, the potential realization of deferred tax assets such as net operating loss carryforwards, utilization of foreign tax credits, and exposure to the disallowance of items deducted on tax returns upon audit.

Certain of our international rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or DFAC, a Cayman Islands subsidiary that we own. It is our intention to indefinitely reinvest future earnings of DFAC and its foreign subsidiaries to finance foreign activities. Accordingly, we have not made a provision for U.S. income taxes on approximately $1.8 billion of undistributed foreign earnings and profits. Although we do not intend to repatriate the earnings of DFAC and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practicable to estimate this potential liability.

In several of the international locations in which we operate, certain of our wholly-owned subsidiaries enter into agreements with other of our wholly-owned subsidiaries to provide specialized services and equipment in support of our foreign operations. We apply a transfer pricing methodology to determine the amount to be charged for providing the services and equipment, and utilize outside consultants to assist us in the development of such transfer pricing methodologies. In most cases, there are alternative transfer pricing methodologies that could be applied to these transactions and, if applied, could result in different chargeable amounts.

Results of Operations

Although we perform contract drilling services with different types of drilling rigs and in many geographic locations, there is a similarity of economic characteristics due to the nature of the revenue-earning process as it relates to the offshore drilling industry, over the operating lives of our drilling rigs. We believe that the combination of our drilling rigs into one reportable segment is the appropriate aggregation in accordance with applicable accounting standards on segment reporting. However, for purposes of this discussion and analysis of our results of operations, we provide greater detail with respect to the types of rigs in our fleet to enhance the reader's understanding of our financial condition, changes in financial condition and results of operations.

Key performance indicators by equipment type are listed below.

	Year Ended December 31, 2016	2015	2014
REVENUE-EARNING DAYS (1)			
Floaters:			
Ultra-Deepwater	2,074	2,690	2,151
Deepwater	844	1,339	1,206
Mid-Water	727	1,433	3,969
Jack-ups	149	909	1,845
UTILIZATION (2)			
Floaters:			
Ultra-Deepwater	51%	64%	65%
Deepwater	34%	52%	55%
Mid-Water	30%	36%	61%
Jack-ups	8%	42%	78%
AVERAGE DAILY REVENUE (3)			
Floaters:			
Ultra-Deepwater	$477,000	$497,700	$459,100
Deepwater	304,600	409,800	409,800
Mid-Water	342,000	270,500	271,300
Jack-ups	202,700	93,400	96,700

(1) A revenue-earning day is defined as a 24-hour period during which a rig earns a dayrate after commencement of operations and excludes mobilization, demobilization and contract preparation days.

(2) Utilization is calculated as the ratio of total revenue-earning days divided by the total calendar days in the period for all specified rigs in our fleet (including cold-stacked rigs, but excluding rigs under construction). As of December 31, 2016, our cold-stacked rigs included four ultra-deepwater semisubmersibles, three deepwater semisubmersibles, and three mid-water semisubmersibles. As of December 31, 2015, our cold-stacked rigs consisted of one ultra-deepwater, two deepwater and four mid-water semisubmersible rigs and five jack-up rigs, which were being marketed for sale at that time. Four jack-up rigs have been sold, and we expect to complete the sale of the *Ocean Spur* in the near future. As of December 31, 2014, six of our mid-water semisubmersible drilling rigs were cold stacked, all of which were sold for scrap in 2015.

(3) Average daily revenue is defined as total contract drilling revenue for all of the specified rigs in our fleet per revenue-earning day.

Comparative data relating to our revenues and operating expenses by equipment type are listed below.

	Year Ended December 31, 2016	2015	2014
		(In thousands)	
CONTRACT DRILLING REVENUE			
Floaters:			
Ultra-Deepwater	$ 989,158	$1,339,059	$ 987,565
Deepwater	256,997	548,667	494,247
Mid-Water	248,846	387,549	1,076,842
Total Floaters	1,495,001	2,275,275	2,558,654
Jack-ups	30,213	84,909	178,472
Total Contract Drilling Revenue	$1,525,214	$2,360,184	$2,737,126
REVENUES RELATED TO REIMBURSABLE EXPENSES	$ 75,128	$ 59,209	$ 77,545
CONTRACT DRILLING EXPENSE			
Floaters:			
Ultra-Deepwater	$ 494,510	$ 620,122	$ 536,615
Deepwater	148,992	277,779	292,050
Mid-Water	84,194	230,606	535,080
Total Floaters	727,696	1,128,507	1,363,745
Jack-ups	17,854	65,699	111,204
Other	26,623	33,658	48,674
Total Contract Drilling Expense	$ 772,173	$1,227,864	$1,523,623
REIMBURSABLE EXPENSES	$ 58,058	$ 58,050	$ 76,091
OPERATING INCOME			
Floaters:			
Ultra-Deepwater	$ 494,648	$ 718,937	$ 450,950
Deepwater	108,005	270,888	202,197
Mid-Water	164,652	156,943	541,762
Total Floaters	767,305	1,146,768	1,194,909
Jack-ups	12,359	19,210	67,268
Other	(26,623)	(33,658)	(48,674)
Reimbursable expenses, net	17,070	1,159	1,454
Depreciation	(381,760)	(493,162)	(456,483)
General and administrative expense	(63,560)	(66,462)	(81,832)
Bad debt expense	265	—	—
Impairment of assets	(678,145)	(860,441)	(109,462)
Restructuring and separation costs	—	(9,778)	—
(Loss) gain on disposition of assets	(3,795)	2,290	5,382
Total Operating (Loss) Income	$ (356,884)	$ (294,074)	$ 572,562
Other income (expense):			
Interest income	768	3,322	801
Interest expense	(89,934)	(93,934)	(62,053)
Foreign currency transaction (loss) gain	(11,522)	2,465	3,199
Other, net	(10,727)	873	682
(Loss) income before income tax benefit (expense)	(468,299)	(381,348)	515,191
Income tax benefit (expense)	95,796	107,063	(128,180)
NET (LOSS) INCOME	$ (372,503)	$ (274,285)	$ 387,011

Overview

2016 Compared to 2015

Operating (Loss) Income. Operating results for 2016 decreased $62.8 million compared to 2015, primarily due to lower utilization of our rig fleet, which reduced both contract drilling revenue and expense for the year. Our operating results for 2016 also reflected an aggregate impairment charge of $678.1 million compared to impairment charges aggregating $860.4 million in 2015. As a result of the impairment charges in 2015 and 2016 and resulting lower depreciable asset base, depreciation expense decreased $111.4 million in 2016 compared to 2015.

Contract drilling revenue decreased $835.0 million, or 35%, during 2016, compared to 2015, due to continued depressed market conditions in all floater markets and for our jack-up rig. Operating results for 2016 reflected an aggregate of 2,577 fewer revenue-earning days compared to 2015, and lower average daily revenue earned by our ultra-deepwater and deepwater floater fleets. Average daily revenue increased for our mid-water and jack-up fleets primarily due to the favorable settlement of a contractual dispute and receipt of loss-of-hire insurance proceeds, each in 2016.

Total contract drilling expense for 2016 decreased $455.7 million, or 37%, compared to 2015, reflecting our lower cost structure due to additional rigs idled, cold stacked or retired during 2015 and 2016, as well as the favorable impact of our cost control initiatives. The reduction in contract drilling expense during 2016 included lower costs associated with labor and personnel ($222.9 million), repairs and maintenance ($63.1 million), mobilization ($71.3 million), shorebase and operational support ($48.1 million), freight ($17.4 million), revenue-based agency fees ($16.1 million), inspections ($8.9 million), and other rig operating expenses ($7.9 million), including rig stacking costs and late start penalties recognized in 2015.

Impairment of Assets. In 2015, we recorded an aggregate impairment loss of $860.4 million related to 17 of our rigs, consisting of two ultra-deepwater, one deepwater and nine mid-water floaters and five jack-up rigs. During 2016, we recognized an aggregate impairment charge of $678.1 million with respect to the carrying values of two mid-water, three deepwater, and three ultra-deepwater floaters, including related rig spares and supplies. See “— Critical Accounting Estimates — *Property, Plant and Equipment*” and Note 2 “Asset Impairments” to our Consolidated Financial Statements in Item 8 of this report.

Restructuring and Separation Costs. During the first quarter of 2015, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, which resulted in the recognition of $9.8 million in restructuring and other employee separation related costs in 2015.

Foreign Currency Transaction (Loss) Gain. Foreign currency transaction gains and losses include both realized and unrealized gains and losses which fluctuate based on the level of transactions in foreign currencies, as well as fluctuations in such currencies. In 2016, we recognized realized and unrealized net foreign currency losses of $3.4 million and $8.1 million, respectively. In 2015, we recognized realized net foreign currency gains of $5.1 million, partially offset by an unrealized net foreign currency loss of $2.6 million.

Other, net. During the second quarter of 2016, we sold our investment in privately-placed corporate bonds for a total recognized loss of $12.1 million.

Income Tax Expense. Our effective tax rate for 2016 was (20.5)% compared to a (28.1)% effective tax rate for 2015. The variance in the tax rate was due to differences in the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken during both 2016 and 2015 in various jurisdictions, with differing tax consequences. The 2016 period was also favorably impacted by a $43.0 million adjustment, primarily to our Egyptian tax liability for uncertain tax positions primarily related to the devaluation of the Egyptian Pound.

2015 Compared to 2014

Operating (Loss) Income. We incurred an operating loss of $294.1 million in 2015 compared to operating income of $572.6 million in 2014. Our operating results for 2015 reflected an aggregate impairment loss of $860.4 million,

$9.8 million in restructuring and severance costs, and a $96.2 million net reduction in rig operating results for our combined floater fleet and jack-up rigs, compared to 2014. Depreciation expense increased $36.7 million in 2015, compared to 2014, due to a higher depreciable asset base in 2015, including the *Ocean Apex* and two newbuild drillships, which were placed in service in December 2014, partially offset by the absence of depreciation for certain of our rigs that were impaired or sold during late 2014 and in 2015.

Total contract drilling revenue declined $376.9 million, or 14%, during 2015 compared to 2014, primarily due to a $782.9 million decrease in revenue earned by our combined mid-water and jack-up fleets, partially offset by an aggregate $405.9 million increase in revenue earned by our ultra-deepwater and deepwater floaters. Our results for 2015 reflected an aggregate 2,800 fewer revenue-earning days, compared to 2014, primarily due to the cold stacking of additional rigs, rig sales and incremental downtime between contracts, partially offset by incremental revenue generating days for newly constructed, upgraded or enhanced rigs, which commenced or resumed drilling operations in 2015.

Total contract drilling expense for 2015 decreased $295.8 million, or 19%, compared to the prior year, primarily due to lower rig utilization, combined with our cost control initiatives. Contract drilling expense for 2015, compared to 2014, reflected lower costs for labor and personnel ($165.8 million), repairs and maintenance ($70.1 million), inspections ($17.2 million), freight ($17.9 million), rig insurance ($9.7 million) and a net decrease in other rig operating costs, including costs associated with our international shorebases, overhead costs and revenue-based agency fees ($72.6 million), partially offset by higher rig mobilization expense ($57.6 million).

Impairment of Assets. During the third quarter of 2014, our management adopted a plan to scrap six of our mid-water semisubmersible rigs, all of which were sold by the end of 2015. As a result of this decision, we recognized an impairment loss of $109.5 million during 2014 to write down the aggregate net book value of these rigs to their estimated recoverable amounts. During 2015, in response to pending regulatory requirements in the GOM at the time, as well as the continued deterioration of market fundamentals in the oil and gas industry, we determined that the carrying value of 17 of our rigs were impaired and, therefore, recorded an aggregate impairment loss of $860.4 million for the year ended December 31, 2015. See "— Critical Accounting Estimates — *Property, Plant and Equipment*" and Note 2 "Asset Impairments" to our Consolidated Financial Statements in Item 8 of this report.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $31.9 million during 2015, compared to 2014, primarily as a result of less interest capitalized during 2015 ($44.3 million) due to the completion of five qualifying construction projects in 2014 and 2015. This increase was partially offset by a $12.3 million reduction in interest expense for 2015, primarily due to the repayment of two tranches of our senior notes in September 2014 and July 2015, reduced by additional interest expense on short-term borrowings during 2015.

Income Tax Expense. Our effective tax rate for 2015 was (28.1)%, compared to a 24.9% effective tax rate for 2014. The variance in the tax rate was due to differences in the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken during both 2015 and 2014 in various jurisdictions, with differing tax consequences. The 2014 period also included the reversal of $55.4 million of reserves for uncertain tax positions in various foreign jurisdictions which were settled in our favor or for which the statute of limitations had expired, compared to a similar reversal of $9.5 million in 2015.

Contract Drilling Revenue and Expense by Equipment Type

2016 Compared to 2015

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters during 2016 decreased $349.9 million compared to 2015, primarily as a result of 616 fewer revenue-earning days ($306.8 million), combined with lower average daily revenue earned ($43.1 million). Revenue-earning days for 2016 decreased primarily due to fewer revenue-earning days for currently cold-stacked rigs that had operated during 2015 (716 days) and the *Ocean Clipper*, which was sold in late 2015 (245 days), and unplanned downtime for repairs (22 days). The aggregate decrease in revenue-earning days was partially offset by incremental revenue-earning days for our drillships (185 days), and the *Ocean Monarch*, which was warm stacked for the first half of 2015 (182 days). Average daily revenue decreased in 2016 primarily due to lower amortized mobilization and contract preparation revenue compared to 2015.

Excluding our four drillships and the *Ocean GreatWhite*, which was placed in service in late 2016, contract drilling expense for our ultra-deepwater floaters decreased $200.5 million during 2016, compared to 2015, reflecting lower expense for labor and personnel ($92.7 million), maintenance and inspections ($38.5 million), mobilization ($26.8 million), shorebase and operational support ($16.2 million), freight ($9.8 million), revenue-based agency fees ($8.2 million), and other rig operating and overhead costs ($8.3 million). These reductions in contract drilling expense were primarily due to lower costs for our cold-stacked rigs and the *Ocean Clipper*, as well as other cost reduction initiatives. Incremental contract drilling expense for our four drillships and the *Ocean GreatWhite* was $74.9 million in 2016, including incremental costs associated with the PCbtH program on our drillships.

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $291.7 million in 2016, compared to 2015, primarily due to 495 fewer revenue-earning days ($202.9 million), combined with a lower average daily revenue earned ($88.7 million). The net reduction in revenue-earning days in 2016 reflected 782 fewer days for currently cold-stacked rigs that had operated in 2015, partially offset by incremental revenue-earning days for other deepwater rigs with contracts that commenced in mid-2015 and in 2016. Average daily revenue decreased primarily as a result of lower amortized mobilization and contract preparation fees ($21.9 million), combined with lower dayrates earned by the *Ocean Valiant* and *Ocean Apex* during 2016 compared to 2015.

Contract drilling expense incurred by our deepwater floaters decreased $128.8 million during 2016, compared to 2015, primarily due to lower costs associated with cold-stacked rigs and cost control initiative in our onshore bases and corporate facilities. Compared to the prior year, contract drilling expense for our deepwater floaters in 2016 reflected reductions in costs for labor and personnel ($51.3 million), mobilization of rigs ($29.5 million), repairs, maintenance and inspections ($18.7 million), shorebase and operational support ($15.1 million), revenue-based agency fees ($4.4 million), freight ($4.1 million) and other operating costs ($5.7 million).

Mid-Water Floaters. Revenue generated by our mid-water floaters during 2016 decreased $138.7 million compared to 2015, primarily due to 706 fewer revenue-earning days ($191.0 million), partially offset by higher average daily revenue earned ($52.0 million), which included a $36.0 million settlement received in connection with a contractual dispute with a former customer. Revenue-earning days decreased in 2016, primarily due to fewer mid-water floaters operating under contracts during 2016 (three rigs) compared to 2015 (nine rigs). We currently have five mid-water floaters in our active rig fleet, two of which are currently operating under contract and the remaining three of which are cold stacked.

Contract drilling expense for our mid-water floaters decreased $146.4 million in 2016, compared to 2015, reflecting a reduction in costs attributable to rigs that have been retired ($109.0 million). Other cost reductions in 2016, compared to 2015, include lower costs for labor and personnel ($19.1 million), maintenance, repairs and inspections ($9.9 million), shorebase and operational support ($6.1 million) and other ($2.3 million), primarily due to lower activity and cost control initiatives.

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $54.7 million and $47.8 million, respectively, during 2016 compared to the prior year. Revenue-earning days decreased by 760 days due to the cold stacking of three rigs that operated under contract during 2015 and an early contract termination for the *Ocean Scepter* in 2016. We currently have one jack-up rig in our active fleet, the *Ocean Scepter*, which is expected to commence operations offshore Mexico in the first quarter of 2017.

2015 Compared to 2014

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $351.5 million during 2015, compared to 2014, primarily as a result of 539 incremental revenue-earning days ($247.6 million), combined with higher average daily revenue earned ($103.9 million). Total revenue-earning days increased in 2015 primarily due to incremental revenue-earning days for our drillships (621 additional days), the *Ocean Endeavor* offshore Romania (149 additional days) and the *Ocean Monarch* offshore Australia (105 additional days), partially offset by fewer revenue-earning days for our other ultra-deepwater floaters (336 fewer days), including the early termination of drilling contracts for the *Ocean Baroness* and *Ocean Clipper*. Average daily revenue increased in 2015 compared to 2014, primarily due to revenue associated with the operation of three additional drillships in 2015, the *Ocean Endeavor*, which included higher amortized mobilization and contract preparation revenue, and a favorable dayrate adjustment for the *Ocean Courage*.

Contract drilling expense for our ultra-deepwater floaters increased $83.5 million during 2015, compared to 2014, and included incremental costs for our newbuild drillships ($153.4 million), partially offset by lower aggregate costs for our other ultra-deepwater floaters ($69.9 million). The decrease in contract drilling expense in 2015 for our other ultra-deepwater floaters reflected lower costs for labor and personnel ($42.6 million), repairs and maintenance ($11.5 million), rig mobilization and inspections ($2.3 million) and other rig operating costs ($13.5 million).

Deepwater Floaters. Revenue generated by our deepwater floaters increased $54.4 million in 2015, compared to 2014, primarily due to 133 incremental revenue-earning days ($54.5 million). The increase in revenue-earning days during 2015 resulted from incremental operating days for four of our deepwater floaters after prolonged periods of nonproductive time for planned upgrades and surveys, as well as warm stacking between contracts (501 incremental days), partially offset by fewer revenue-earning days due to the cold stacking of the *Ocean Star* (233 days) and additional non-revenue-earning days for rig mobilization and repairs (135 additional days).

Contract drilling expense for our deepwater floaters decreased an aggregate $14.3 million in 2015, compared to 2014, reflecting lower labor and personnel related costs ($10.0 million), repairs and maintenance ($17.0 million) and other rig operating costs ($7.5 million). These reductions in contract drilling expense in 2015, compared to 2014, were partially offset by higher amortized rig mobilization expense ($20.2 million), primarily related to drilling rigs that returned to service in 2015.

Mid-Water Floaters. Revenue generated by our mid-water floaters decreased $689.3 million in 2015, compared to 2014, primarily due to 2,536 fewer revenue-earning days ($688.1 million) combined with lower average daily revenue earned ($1.2 million). The reduction in revenue-earning days during 2015 resulted from the cold stacking or retirement of twelve mid-water rigs (2,638 fewer days) and the idling of two mid-water floaters between contracts (288 fewer days), partially offset by incremental revenue-earning days for the upgraded *Ocean Patriot* operating in the North Sea (296 additional days) and the *Ocean Ambassador* (94 additional days).

Contract drilling expense for our mid-water floaters decreased $304.5 million in 2015, compared to 2014, primarily due to reduced operating costs for our idled, cold-stacked and retired mid-water rigs ($344.1 million), partially offset by incremental operating costs for the *Ocean Patriot* ($36.9 million).

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $93.6 million and $45.5 million, respectively, during 2015, compared to 2014, primarily due to reduced utilization for five rigs that were under contract in 2014, but were cold stacked and marketed for sale at the end of 2015. Contract drilling revenue for 2015 was also negatively impacted by a negotiated dayrate reduction for the *Ocean Scepter*.

Liquidity and Capital Resources

We principally rely on our cash flows from operations and cash reserves to meet our liquidity needs and may also utilize borrowings under our $1.5 billion syndicated revolving credit agreement, or Credit Agreement for such purposes. See "— Credit Agreement and Senior Notes."

Based on our cash available for current operations and contractual backlog of $3.6 billion, as of January 1, 2017, of which $1.5 billion is expected to be realized in 2017, we believe future capital spending and debt service requirements will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See "— Cash Flow and Capital Expenditures — *Capital Expenditures*" and "Risk Factors — *We can provide no assurance that our drilling contracts will not be terminated early or that our current backlog of contract drilling revenue will be ultimately realized*" in Item 1A of this report.

Certain of our international rigs are owned and operated, directly or indirectly, by DFAC and, as a result of our intention to indefinitely reinvest the earnings of DFAC and its foreign subsidiaries to finance our foreign activities, we do not expect such earnings to be available for distribution to our stockholders or to finance our domestic activities. See "— Market Overview — Critical Accounting Estimates — Income Taxes." To the extent available, we expect to utilize the operating cash flows generated by and cash reserves of DFAC and the operating cash flows available to and cash reserves of Diamond Offshore Drilling, Inc. to meet each entity's respective working capital requirements and capital commitments.

At December 31, 2016, 2015 and 2014, we had cash available for current operations, including cash reserves of DFAC, as follows:

	December 31,		
	2016	2015	2014
		(In thousands)	
Cash and cash equivalents	$156,233	$119,028	$233,623
Marketable securities	35	11,518	16,033
Total cash available for current operations	$156,268	$130,546	$249,656

A substantial portion of our cash flows has been invested in the enhancement of our drilling fleet, including $3.5 billion since 2014 for the construction of five newbuild rigs, the major upgrade of two semisubmersible rigs and other capital enhancement projects. We determine the amount of cash required to meet our capital commitments by evaluating our rig construction obligations, the need to upgrade rigs to meet specific customer requirements and our ongoing rig equipment enhancement/replacement programs. We also make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments thereto if required. See "– Cash Flow and Capital Expenditures."

We paid regular and special cash dividends aggregating $550.2 million during the three-year period ended December 31, 2016. We discontinued our special cash dividend in 2014 and our quarterly regular cash dividend in 2016. We did not pay any dividends in 2016.

We pay dividends at the discretion of our Board of Directors, or Board, and any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board's consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs and other factors that our Board of Directors considers relevant at that time. Our dividend policy may change from time to time, and there can be no assurance that we will declare any cash dividends at all or in any particular amounts. See "Risk Factors — *Although we have paid cash dividends in the past, we did not pay any dividends in 2016 and we may not pay regular or special cash dividends in the future and we can give no assurance as to the amount or timing of the payment of any future regular or special cash dividends*" in Item 1A of this report, which is incorporated herein by reference.

Depending on market conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We did not purchase any of our outstanding common stock during 2016 or 2015. During 2014, we repurchased 1,895,561 shares of our outstanding common stock at a cost of $87.8 million.

Proceeds from the sale of assets included $210.0 million in 2016 related to the sale of certain well control equipment on our drillships and $39.7 million from the sale of 20 drilling rigs during the three-year period ended December 31, 2016. See "— Contractual Cash Obligations — *Pressure Control by the Hour*."

During 2015 and 2014, we repaid two tranches of maturing senior notes of $250.0 million each.

We may, from time to time, issue debt or equity securities, or a combination thereof, to finance capital expenditures, the acquisition of assets and businesses or for general corporate purposes. Our ability to access the capital markets by issuing debt or equity securities will be dependent on our results of operations, our current financial condition, current credit ratings, current market conditions and other factors beyond our control.

Cash Flow and Capital Expenditures

Our cash flow from operations and capital expenditures for each of the years in the three-year period ended December 31, 2016 was as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Cash flow from operations	$646,554	$736,427	$ 992,831
Capital expenditures:			
Drillship construction	$ 55,426	$454,093	$1,318,271
Major upgrade of deepwater floaters	—	34,723	168,045
Construction of ultra-deepwater floater	503,172	55,805	18,223
Ocean Patriot enhancement program	—	2,669	107,181
Ocean Confidence service-life-extension project	—	72,124	134,871
Rig equipment and replacement program	94,075	211,241	286,173
Total capital expenditures	$652,673	$830,655	$2,032,764

Cash Flow. Cash flow from operations decreased approximately $89.9 million during 2016, compared to 2015, primarily due to lower cash receipts from contract drilling services ($704.9 million), partially offset by a $584.8 million net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, maintenance, mobilization, shorebase and operational support and other rig operating costs and lower income taxes paid, net of refunds ($30.2 million). The decline in cash receipts from and cash payments related to contract drilling services both reflect an aggregate decline in our contract drilling operations, as well as a lower cost structure and the favorable impact of our cost control initiatives.

Cash flow from operations decreased approximately $256.4 million during 2015, compared to 2014, primarily due to lower cash receipts from contract drilling services ($444.8 million), partially offset by a $144.4 million net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, maintenance, mobilization and other rig operating costs and lower income taxes paid, net of refunds ($44.0 million). The decline in cash receipts from and cash payments related to contract drilling services both reflect an aggregate decline in our contract drilling operations, as well as our efforts to control costs.

See "— Results of Operations — Years Ended December 31, 2016, 2015 and 2014."

Capital Expenditures. As of the date of this report, we expect capital expenditures for 2017 to aggregate approximately $135.0 million for our ongoing capital maintenance and replacement programs. We expect to fund our 2017 capital spending from the operating cash flows generated by and cash reserves of DFAC and the operating cash flows available to and cash reserves of Diamond Offshore Drilling, Inc., as well as borrowings under our Credit Agreement.

Credit Agreement and Senior Notes

Credit Agreement. Our Credit Agreement provides for a $1.5 billion senior unsecured revolving credit facility for general corporate purposes maturing on October 22, 2020, except for $40 million of commitments that mature on

March 17, 2019 and $60 million of commitments that mature on October 22, 2019. As of December 31, 2016, we had $104.2 million in borrowings outstanding under the Credit Agreement, and we were in compliance with all covenant requirements. As of February 10, 2017, we had no borrowings outstanding and $1.5 billion available under our Credit Agreement to provide short-term liquidity for our payment obligations.

As of December 31, 2016, we had an aggregate $2.0 billion in long-term, unsecured senior notes outstanding, of which $500.0 million will mature in 2019 and the remainder will mature at various times beginning in 2023.

See Note 10 "Credit Agreement, Commercial Paper and Senior Notes" to our Consolidated Financial Statements in Item 8 of this report.

Credit Ratings. In November 2016, S&P Global Ratings, or S&P, downgraded our corporate credit rating to BB+ from BBB, and, in January 2017, further downgraded our corporate credit rating to BB-, with a negative outlook. Our current corporate credit rating by Moody's Investor Services is Ba2 with a stable outlook. Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered further. A downgrade in our credit ratings could adversely impact our cost of issuing additional debt and the amount of additional debt that we could issue, and could further restrict our access to capital markets and our ability to raise additional debt. As a consequence, we may not be able to issue additional debt in amounts and/or with terms that we consider to be reasonable. One or more of these occurrences could limit our ability to pursue other business opportunities.

As a result of a downgrade in our short-term credit rating, in the first quarter of 2016 we canceled our commercial paper program due to our inability to access the commercial paper market in the foreseeable future.

Contractual Cash Obligations

The following table sets forth our contractual cash obligations at December 31, 2016.

	Payments Due By Period				
Contractual Obligations [1]	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
	(In thousands)				
Long-term debt (principal and interest)	$3,776,500	$103,062	$691,438	$147,375	$2,834,625
PCbtH program	615,000	65,000	130,000	130,000	290,000
Property leases	2,477	1,758	580	107	32
Total obligations	$4,393,977	$169,820	$822,018	$277,482	$3,124,657

(1) The above table excludes $36.0 million of unrecognized tax benefits related to uncertain tax positions as of December 31, 2016 and an additional $16.8 million and $2.6 million for potential penalties and interest, respectively, related to such uncertain tax positions. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in these balances, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities.

Pressure Control by the Hour. In February 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide services with respect to certain blowout preventer and related well control equipment on our four drillships. Such services include management of maintenance, certification and reliability with respect to such equipment. In connection with the services agreement with GE, we sold the equipment to a GE affiliate for an aggregate $210.0 million and are leasing back such equipment over separate ten-year operating leases. Collectively, we refer to the services agreement with GE and the lease agreements with the GE affiliate as the "PCbtH program." See Note 13 "Sale and Leaseback Transactions" to our Consolidated Financial Statements in Item 8 of this report.

Except for our contractual requirements under the PCbtH program discussed above, we had no other purchase obligations for major rig upgrades or any other significant obligations at December 31, 2016, except for those related to our direct rig operations, which arise during the normal course of business.

Other Commercial Commitments — Letters of Credit

We were contingently liable as of December 31, 2016 in the amount of $57.2 million under certain performance, tax, supersedeas, court and customs bonds and letters of credit. Agreements relating to approximately $53.9 million of performance, tax, supersedeas, court and customs bonds can require collateral at any time. As of December 31, 2016, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. Banks have issued letters of credit on our behalf securing certain of these bonds. The table below provides a list of these obligations in U.S. dollar equivalents and their time to expiration.

	Total	For the Years Ending December 31, 2017	2018	2019	2020
		(In thousands)			
Other Commercial Commitments					
Performance bonds	$40,177	$15,754	$5,298	$—	$19,125
Supersedeas bond	9,189	9,189	—	—	—
Tax bond	4,942	4,942	—	—	—
Other	2,908	2,538	370	—	—
Total obligations	$57,216	$32,423	$5,668	$—	$19,125

Off-Balance Sheet Arrangements

At December 31, 2016 and 2015, we had no off-balance sheet debt or other off-balance sheet arrangements.

Other

Currency Risk. Some of our subsidiaries conduct a portion of their operations in the local currency of the country where they conduct operations, resulting in foreign currency exposure. Currency environments in which we currently have or previously had significant business operations include Australia, Brazil, Egypt, Malaysia, Mexico, Trinidad and Tobago and the U.K., creating exposure to certain monetary assets and liabilities denominated in currencies other than the U.S. dollar. These assets and liabilities are revalued based on currency exchange rates at the end of the reporting period.

To minimize our currency exchange risk, we may, if possible, arrange for a portion of our international contracts to be payable to us in local currency in amounts equal to our estimated operating costs payable in local currency, with the balance of the contract payable in U.S. dollars. At present, however, only a limited number of our contracts are payable both in U.S. dollars and the local currency. Historically, to the extent that we have not been able to cover our local currency operating costs with customer payments in the local currency, we have also utilized foreign currency forward exchange, or FOREX, contracts to reduce our currency exchange risk. We currently have no outstanding FOREX contracts. We record currency transaction gains and losses and gains and losses arising from the settlement of our FOREX contracts that have been designated as cash flow hedges as "Foreign currency transaction gain (loss)'' and "Contract drilling, excluding depreciation" expense, respectively, in our Consolidated Statements of Operations. The revaluation of liabilities for uncertain tax positions denominated in currencies other than the U.S. dollar is reported as a component of "Income tax (benefit) expense," in our Consolidated Statements of Operations.

Forward-Looking Statements

We or our representatives may, from time to time, either in this report, in periodic press releases or otherwise, make or incorporate by reference certain written or oral statements that are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain or be identified by the words "expect," "intend," "plan," "predict," "anticipate," "estimate," "believe," "should," "could," "may," "might," "will," "will be," "will continue," "will likely result," "project," "forecast," "budget" and similar expressions. In addition, any statement concerning future financial performance (including, without limitation, future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by or against us, which may be provided by management, are also forward-looking statements as so defined. Statements made by us in this report that contain forward-looking statements may include, but are not limited to, information concerning our possible or assumed future results of operations and statements about the following subjects:

- market conditions and the effect of such conditions on our future results of operations;
- sources and uses of and requirements for financial resources and sources of liquidity;
- contractual obligations and future contract negotiations;
- interest rate and foreign exchange risk;
- operations outside the United States;
- business strategy;
- growth opportunities;
- competitive position, including without limitation, competitive rigs entering the market;
- expected financial position;
- cash flows and contract backlog;
- future term of the Petrobras drilling contract for the *Ocean Valor* and the enforcement of our rights under the contract;
- future dayrates and term for the *Ocean GreatWhite;*
- idling drilling rigs or reactivating stacked rigs;
- declaration and payment of regular or special dividends;
- financing plans;
- market outlook;
- tax planning;
- debt levels and the impact of changes in the credit markets and credit ratings for our debt;
- budgets for capital and other expenditures;
- timing and duration of required regulatory inspections for our drilling rigs;
- timing and cost of completion of capital projects;
- delivery dates and drilling contracts related to capital projects or rig acquisitions;
- plans and objectives of management;
- idling drilling rigs or reactivating stacked rigs;
- scrapping retired rigs;

- asset impairments and impairment evaluations;
- our internal controls and remediation of our material weakness in internal control over financial reporting;
- effective date and performance of contracts;
- outcomes of legal proceedings;
- purchases of our securities;
- compliance with applicable laws; and
- availability, limits and adequacy of insurance or indemnification.

These types of statements are based on current expectations about future events and inherently are subject to a variety of assumptions, risks and uncertainties, many of which are beyond our control, that could cause actual results to differ materially from those expected, projected or expressed in forward-looking statements. These risks and uncertainties include, among others, the following:

- those described under “Risk Factors” in Item 1A;
- general economic and business conditions and trends, including recessions and adverse changes in the level of international trade activity;
- worldwide supply and demand for oil and natural gas;
- changes in foreign and domestic oil and gas exploration, development and production activity;
- oil and natural gas price fluctuations and related market expectations;
- the ability of OPEC to set and maintain production levels and pricing, and the level of production in non-OPEC countries;
- policies of various governments regarding exploration and development of oil and gas reserves;
- inability to obtain contracts for our rigs that do not have contracts;
- the cancellation of contracts included in our reported contract backlog;
- advances in exploration and development technology;
- the worldwide political and military environment, including, for example, in oil-producing regions and locations where our rigs are operating or are under construction;
- casualty losses;
- operating hazards inherent in drilling for oil and gas offshore;
- the risk that dividends may not be declared or paid;
- the risk of physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico;
- industry fleet capacity;
- market conditions in the offshore contract drilling industry, including, without limitation, dayrates and utilization levels;

- competition;
- changes in foreign, political, social and economic conditions;
- risks of international operations, compliance with foreign laws and taxation policies and seizure, expropriation, nationalization, deprivation, malicious damage or other loss of possession or use of equipment and assets;
- risks of potential contractual liabilities pursuant to our various drilling contracts in effect from time to time;
- customer or supplier bankruptcy, liquidation or other financial difficulties;
- the ability of customers and suppliers to meet their obligations to us and our subsidiaries;
- collection of receivables;
- foreign exchange and currency fluctuations and regulations, and the inability to repatriate income or capital;
- risks of war, military operations, other armed hostilities, terrorist acts and embargoes;
- changes in offshore drilling technology, which could require significant capital expenditures in order to maintain competitiveness;
- regulatory initiatives and compliance with governmental regulations including, without limitation, regulations pertaining to climate change, greenhouse gases, carbon emissions or energy use;
- compliance with and liability under environmental laws and regulations;
- potential changes in accounting policies by the Financial Accounting Standards Board, the Securities and Exchange Commission, or SEC, or regulatory agencies for our industry which may cause us to revise our financial accounting and/or disclosures in the future, and which may change the way analysts measure our business or financial performance;
- development and exploitation of alternative fuels;
- customer preferences;
- effects of litigation, tax audits and contingencies and the impact of compliance with judicial rulings and jury verdicts;
- cost, availability, limits and adequacy of insurance;
- invalidity of assumptions used in the design of our controls and procedures and the risk that the measures we take to remediate our material weakness in internal control over financial reporting will not be effective or that additional material weaknesses may arise in the future;
- the results of financing efforts;
- adequacy and availability of our sources of liquidity;
- risks resulting from our indebtedness;
- public health threats;
- negative publicity;
- impairments of assets; and
- the availability of qualified personnel to operate and service our drilling rigs.

The risks and uncertainties included here are not exhaustive. Other sections of this report and our other filings with the SEC include additional factors that could adversely affect our business, results of operations and financial performance. Given these risks and uncertainties, investors should not place undue reliance on forward-looking statements. Forward-looking statements included in this report speak only as of the date of this report. We expressly disclaim any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement to reflect any change in our expectations or beliefs with regard to the statement or any change in events, conditions or circumstances on which any forward-looking statement is based. In addition, in certain places in this report, we may refer to reports published by third parties that purport to describe trends or developments in energy production or drilling and exploration activity. We do so for the convenience of our investors and potential investors and in an effort to provide information available in the market intended to lead to a better understanding of the market environment in which we operate. We specifically disclaim any responsibility for the accuracy and completeness of such information and undertake no obligation to update such information.

New Accounting Pronouncements

For a discussion of recent accounting pronouncements, which are not yet effective, and their effect on our financial position, results of operations and cash flows, see Note 1 "General Information — *Recent Accounting Pronouncements*" to our Consolidated Financial Statements in Item 8 of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The information included in this Item 7A is considered to constitute "forward-looking statements" for purposes of the statutory safe harbor provided in Section 27A of the Securities Act and Section 21E of the Exchange Act. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Statements" in Item 7 of this report.

Our measure of market risk exposure represents an estimate of the change in fair value of our financial instruments. Market risk exposure is presented for each class of financial instrument held by us at December 31, 2016 and 2015, assuming immediate adverse market movements of the magnitude described below. We believe that the various rates of adverse market movements represent a measure of exposure to loss under hypothetically assumed adverse conditions. The estimated market risk exposure represents the hypothetical loss to future earnings and does not represent the maximum possible loss or any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. In addition, since our investment portfolio is subject to change based on our portfolio management strategy as well as in response to changes in the market, these estimates are not necessarily indicative of the actual results that may occur.

Exposure to market risk is managed and monitored by our senior management. Senior management approves the overall investment strategy that we employ and has responsibility to ensure that the investment positions are consistent with that strategy and the level of risk acceptable to us. We may manage risk by buying or selling instruments or entering into offsetting positions.

Interest Rate Risk. We have exposure to interest rate risk arising from changes in the level or volatility of interest rates. Our investments in marketable securities are primarily in fixed maturity securities. We monitor our sensitivity to interest rate risk by evaluating the change in the value of our financial assets and liabilities due to fluctuations in interest rates. The evaluation is performed by applying an instantaneous change in interest rates by varying magnitudes on a static balance sheet to determine the effect such a change in rates would have on the recorded market value of our investments and the resulting effect on stockholders' equity. The analysis presents the sensitivity of the market value of our financial instruments to selected changes in market rates and prices which we believe are reasonably possible over a one-year period.

The sensitivity analysis estimates the change in the market value of our interest sensitive assets and liabilities that were held on December 31, 2016 and 2015, due to instantaneous parallel shifts in the yield curve of 100 basis points, with all other variables held constant.

The interest rates on certain types of assets and liabilities may fluctuate in advance of changes in market interest rates, while interest rates on other types may lag behind changes in market rates. Accordingly, the analysis may not be indicative of, is not intended to provide, and does not provide a precise forecast of the effect of changes in market interest rates on our earnings or stockholders' equity. Further, the computations do not contemplate any actions we could undertake in response to changes in interest rates.

Our long-term debt, as of December 31, 2016 and 2015, is denominated in U.S. dollars. Our existing debt has been issued at fixed rates, and as such, interest expense would not be impacted by interest rate shifts. The impact of a 100-basis point increase in interest rates on fixed rate debt would result in a decrease in market value of $125.3 million and $112.7 million as of December 31, 2016 and 2015, respectively. A 100-basis point decrease would result in an increase in market value of $147.3 million and $131.3 million as of December 31, 2016 and 2015, respectively.

Foreign Exchange Risk. Foreign exchange rate risk arises from the possibility that changes in foreign currency exchange rates will impact the value of financial instruments. In the past we have entered into FOREX contracts in the normal course of business. Historically, these contracts generally required us to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date, which for most of our contracts is the average spot rate for the contract period. We had no FOREX contracts outstanding at December 31, 2016 or 2015.

The following table presents our exposure to interest rate risk:

	Fair Value Asset		Market Risk	
	December 31,		December 31,	
	2016	2015	2016	2015
	(In thousands)			
Interest rate:				
Marketable securities	$35 [a]	$11,500 [a]	$— [b]	$(300) [b]

(a) The fair market value of our investment in marketable securities, excluding repurchase agreements, is based on the quoted closing market prices on December 31, 2016 and 2015.

(b) The calculation of estimated market risk exposure is based on assumed adverse changes in the underlying reference price or index of an increase in interest rates of 100 basis points at December 31, 2016 and 2015.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Diamond Offshore Drilling, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of Diamond Offshore Drilling, Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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, such consolidated financial statements present fairly, in all material respects, the financial position of Diamond Offshore Drilling, Inc. and subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2017 expressed an adverse opinion on the Company's internal control over financial reporting because of a material weakness.

/s/ Deloitte & Touche LLP

Houston, Texas
February 16, 2017

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 156,233	$ 119,028
Marketable securities	35	11,518
Accounts receivable, net of allowance for bad debts	247,028	405,370
Prepaid expenses and other current assets	102,111	119,479
Assets held for sale	400	14,200
Total current assets	505,807	669,595
Drilling and other property and equipment, net of accumulated depreciation	5,726,935	6,378,814
Other assets	139,135	101,485
Total assets	$6,371,877	$7,149,894
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 30,242	$ 70,272
Accrued liabilities	182,159	253,769
Taxes payable	23,898	15,093
Short-term borrowings	104,200	286,589
Total current liabilities	340,499	625,723
Long-term debt	1,980,884	1,979,778
Deferred tax liability	197,011	276,529
Other liabilities	103,349	155,094
Total liabilities	2,621,743	3,037,124
Commitments and contingencies (Note 12)	—	—
Stockholders' equity:		
Preferred stock (par value $0.01, 25,000,000 shares authorized, none issued and outstanding)	—	—
Common stock (par value $0.01, 500,000,000 shares authorized; 143,997,757 shares issued and 137,169,663 shares outstanding at December 31, 2016; 143,978,877 shares issued and 137,158,706 shares outstanding at December 31, 2015)	1,440	1,440
Additional paid-in capital	2,004,514	1,999,634
Retained earnings	1,946,765	2,319,136
Accumulated other comprehensive gain (loss)	1	(5,035)
Treasury stock, at cost (6,828,094 and 6,820,171 shares of common stock at December 31, 2016 and 2015, respectively)	(202,586)	(202,405)
Total stockholders' equity	3,750,134	4,112,770
Total liabilities and stockholders' equity	$6,371,877	$7,149,894

The accompanying notes are an integral part of the consolidated financial statements.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Contract drilling	$1,525,214	$2,360,184	$2,737,126
Revenues related to reimbursable expenses	75,128	59,209	77,545
Total revenues	1,600,342	2,419,393	2,814,671
Operating expenses:			
Contract drilling, excluding depreciation	772,173	1,227,864	1,523,623
Reimbursable expenses	58,058	58,050	76,091
Depreciation	381,760	493,162	456,483
General and administrative	63,560	66,462	81,832
Impairment of assets	678,145	860,441	109,462
Bad debt recovery	(265)	—	—
Restructuring and separation costs	—	9,778	—
Loss (gain) on disposition of assets	3,795	(2,290)	(5,382)
Total operating expenses	1,957,226	2,713,467	2,242,109
Operating (loss) income	(356,884)	(294,074)	572,562
Other income (expense):			
Interest income	768	3,322	801
Interest expense, net of amounts capitalized	(89,934)	(93,934)	(62,053)
Foreign currency transaction (loss) gain	(11,522)	2,465	3,199
Other, net	(10,727)	873	682
(Loss) income before income tax benefit (expense)	(468,299)	(381,348)	515,191
Income tax benefit (expense)	95,796	107,063	(128,180)
Net (loss) income	$ (372,503)	$ (274,285)	$ 387,011
(Loss) earnings per share:			
Basic	$ (2.72)	$ (2.00)	$ 2.82
Diluted	$ (2.72)	$ (2.00)	$ 2.81
Weighted-average shares outstanding:			
Shares of common stock	137,168	137,157	137,473
Dilutive potential shares of common stock	—	—	50
Total weighted-average shares outstanding	137,168	137,157	137,523
Cash dividends declared per share of common stock	$ —	$ 0.50	$ 3.50

The accompanying notes are an integral part of the consolidated financial statements.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME OR LOSS
(In thousands)

	Year Ended December 31,		
	2016	2015	2014
Net (loss) income	$(372,503)	$(274,285)	$387,011
Other comprehensive gains (losses), net of tax:			
Derivative financial instruments:			
Unrealized holding loss	—	(1,574)	(1,482)
Reclassification adjustment for (gain) loss included in net (loss) income	(5)	5,084	(2,379)
Investments in marketable securities:			
Unrealized holding loss on investments	(6,559)	(4,940)	(69)
Reclassification adjustment for loss (gain) included in net (loss) income	11,600	—	(25)
Total other comprehensive gain (loss)	5,036	(1,430)	(3,955)
Comprehensive (loss) income	$(367,467)	$(275,715)	$383,056

The accompanying notes are an integral part of the consolidated financial statements.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except number of shares)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Gains (Losses)	Treasury Stock		Total Stockholders' Equity
	Shares	Amount				Shares	Amount	
January 1, 2014	143,952,248	$1,440	$1,988,720	$2,761,161	$ 350	4,916,800	$(114,413)	$4,637,258
Net income	—	—	—	387,011	—	—	—	387,011
Dividends to stockholders ($3.50 per share)	—	—	—	(481,642)	—	—	—	(481,642)
Anti-dilution adjustment paid to stock plan participants ($3.00 per share)	—	—	—	(4,531)	—	—	—	(4,531)
Treasury stock purchase	—	—	—	—	—	1,895,561	(87,756)	(87,756)
Stock options exercised	8,012	—	213	—	—	—	—	213
Stock-based compensation, net of tax	—	—	4,965	—	—	—	—	4,965
Net loss on derivative financial instruments	—	—	—	—	(3,861)	—	—	(3,861)
Net loss on investments	—	—	—	—	(94)	—	—	(94)
December 31, 2014	143,960,260	1,440	1,993,898	2,661,999	(3,605)	6,812,361	(202,169)	4,451,563
Net loss	—	—	—	(274,285)	—	—	—	(274,285)
Dividends to stockholders ($0.50 per share)	—	—	—	(68,578)	—	—	—	(68,578)
Stock-based compensation, net of tax	18,617	—	5,736	—	—	7,810	(236)	5,500
Net gain on derivative financial instruments	—	—	—	—	3,510	—	—	3,510
Net loss on investments	—	—	—	—	(4,940)	—	—	(4,940)
December 31, 2015	143,978,877	1,440	1,999,634	2,319,136	(5,035)	6,820,171	(202,405)	4,112,770
Net loss	—	—	—	(372,503)	—	—	—	(372,503)
Anti-dilution adjustment	—	—	—	132	—	—	—	132
Stock-based compensation, net of tax	18,880	—	4,880	—	—	7,923	(181)	4,699
Net loss on derivative financial instruments	—	—	—	—	(5)	—	—	(5)
Net gain on investments	—	—	—	—	5,041	—	—	5,041
December 31, 2016	143,997,757	$1,440	$2,004,514	$1,946,765	$ 1	6,828,094	$(202,586)	$3,750,134

The accompanying notes are an integral part of the consolidated financial statements.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2016	2015	2014
Operating activities:			
Net (loss) income	$(372,503)	$(274,285)	$ 387,011
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation	381,760	493,162	456,483
Loss on impairment of assets	678,145	860,441	109,462
Loss (gain) on disposition of assets	3,795	(2,290)	(5,382)
Loss on sale of marketable securities, net	12,146	—	—
Loss (gain) on foreign currency forward exchange contracts	—	8,364	(3,275)
Deferred tax provision	(106,263)	(242,034)	1,532
Stock-based compensation expense	4,880	4,856	3,507
Deferred income, net	(29,108)	(45,383)	60,061
Deferred expenses, net	(20,155)	(26,405)	(82,814)
Other assets, noncurrent	(4,914)	2,483	2,881
Other liabilities, noncurrent	(31)	(3,890)	(3,979)
(Payments of) proceeds from settlement of foreign currency forward exchange contracts designated as accounting hedges	—	(8,364)	3,275
Bank deposits denominated in nonconvertible currencies	3,475	1,069	5,520
Other	2,216	(211)	3,118
Changes in operating assets and liabilities:			
Accounts receivable	159,098	58,872	5,269
Prepaid expenses and other current assets	6,187	19,195	(2,791)
Accounts payable and accrued liabilities	(71,085)	(180,872)	27,463
Taxes payable	(1,089)	71,719	25,490
Net cash provided by operating activities	646,554	736,427	992,831
Investing activities:			
Capital expenditures (including rig construction)	(652,673)	(830,655)	(2,032,764)
Proceeds from disposition of assets, net of disposal costs	221,722	13,049	18,318
Proceeds from sale and maturities of marketable securities	4,614	51	8,000,057
Purchases of marketable securities	—	—	(6,265,846)
Net cash used in investing activities	(426,337)	(817,555)	(280,235)
Financing activities:			
Repayment of long-term debt	—	(250,000)	(250,000)
(Repayment of) proceeds from short-term borrowings, net	(182,389)	286,589	—
Debt issuance costs and arrangement fees	(215)	(624)	(2,249)
Payment of dividends and anti-dilution payments	(408)	(69,432)	(486,240)
Purchase of treasury stock	—	—	(87,756)
Other	—	—	261
Net cash used in financing activities	(183,012)	(33,467)	(825,984)
Net change in cash and cash equivalents	37,205	(114,595)	(113,388)
Cash and cash equivalents, beginning of year	119,028	233,623	347,011
Cash and cash equivalents, end of year	$ 156,233	$ 119,028	$ 233,623

The accompanying notes are an integral part of the consolidated financial statements.

DIAMOND OFFSHORE DRILLING, INC.
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

Diamond Offshore Drilling, Inc. provides contract drilling services to the energy industry around the globe with a fleet of 24 offshore drilling rigs. Our current fleet consists of four drillships, eight ultra-deepwater, six deepwater and five mid-water semisubmersible rigs, and one jack-up rig. The *Ocean Spur* reported as "Assets held for sale" in our Consolidated Balance Sheets at December 31, 2016 is expected to be sold in the near future. Unless the context otherwise requires, references in these Notes to "Diamond Offshore," "we," "us" or "our" mean Diamond Offshore Drilling, Inc. and our consolidated subsidiaries. We were incorporated in Delaware in 1989.

As of February 10, 2017, Loews Corporation, or Loews, owned approximately 53% of the outstanding shares of our common stock.

Principles of Consolidation

Our consolidated financial statements include the accounts of Diamond Offshore Drilling, Inc. and our wholly-owned subsidiaries after elimination of intercompany transactions and balances.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States, or U.S., or GAAP, requires management 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 amount of revenues and expenses during the reporting period. Actual results could differ from those estimated.

Cash and Cash Equivalents

We consider short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash to be cash equivalents.

The effect of exchange rate changes on cash balances held in foreign currencies was not material for the years ended December 31, 2016, 2015 and 2014.

Marketable Securities

We classify our investments in marketable securities as available for sale and they are stated at fair value in our Consolidated Balance Sheets. Accordingly, any unrealized gains and losses, net of taxes, are reported in our Consolidated Balance Sheets in "Accumulated other comprehensive gain (loss)" until realized. The cost of debt securities is adjusted for amortization of premiums and accretion of discounts to maturity and such adjustments are included in our Consolidated Statements of Operations in "Interest income." The sale and purchase of securities are recorded on the date of the trade. The cost of debt securities sold is based on the specific identification method. Realized gains or losses, as well as any declines in value that are judged to be other than temporary, are reported in our Consolidated Statements of Operations in "Other income (expense) – Other, net." See Note 6.

Provision for Bad Debts

We record a provision for bad debts on a case-by-case basis when facts and circumstances indicate that a customer receivable may not be collectible. In establishing these reserves, we consider historical and other factors that predict collectability, including write-offs, recoveries and the monitoring of credit quality. Such provision is reported as a component of "Operating expense" in our Consolidated Statements of Operations. See Note 3.

Derivative Financial Instruments

Our derivative financial instruments have primarily consisted of foreign currency forward exchange, or FOREX, contracts which we may designate as cash flow hedges. In accordance with GAAP, each derivative contract is stated in the balance sheet at its fair value with gains and losses reflected in the income statement except that, to the extent the derivative qualifies for and is designated as an accounting hedge, the gains and losses are reflected in income in the same period as offsetting gains and losses on the qualifying hedged positions. Designated hedges are expected to be highly effective, and therefore, adjustments to record the carrying value of the effective portion of our derivative financial instruments to their fair value are recorded as a component of "Accumulated other comprehensive gain (loss)," or AOCGL, in our Consolidated Balance Sheets. The effective portion of the cash flow hedge will remain in AOCGL until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or it is determined that the hedged transaction will not occur. We report such realized gains and losses as a component of "Contract drilling, excluding depreciation" expense in our Consolidated Statements of Operations to offset the impact of foreign currency fluctuations in our expenditures in local foreign currencies in the countries in which we operate.

Adjustments to record the carrying value of the ineffective portion of our derivative financial instruments to fair value and realized gains or losses upon settlement of derivative contracts not designated as cash flow hedges are reported as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations. See Notes 7 and 8.

Assets Held For Sale

We reported the $0.4 million and $14.2 million carrying values of certain of our jack-up rigs as "Assets held for sale" in our Consolidated Balance Sheets at December 31, 2016 and 2015, respectively. Four of these rigs were sold during 2016 and the remaining jack-up rig reported as "Assets held for sale" at December 31, 2016 is expected to be sold in the near future. See Note 2.

Drilling and Other Property and Equipment

We carry our drilling and other property and equipment at cost, less accumulated depreciation. Maintenance and routine repairs are charged to income currently while replacements and betterments that upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset, are capitalized. Significant judgments, assumptions and estimates may be required in determining whether or not such replacements and betterments meet the criteria for capitalization and in determining useful lives and salvage values of such assets. Changes in these judgments, assumptions and estimates could produce results that differ from those reported. During the years ended December 31, 2016 and 2015, we capitalized $177.6 million and $262.4 million, respectively, in replacements and betterments of our drilling fleet.

Costs incurred for major rig upgrades and/or the construction of rigs are accumulated in construction work-in-progress, with no depreciation recorded on the additions, until the month the upgrade or newbuild is completed and the rig is placed in service. Upon retirement or sale of a rig, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are included in our results of operations as "Loss (gain) on disposition of assets." Depreciation is recognized up to applicable salvage values by applying the straight-line method over the remaining estimated useful lives from the year the asset is placed in service. Drilling rigs and equipment are depreciated over their estimated useful lives ranging from 3 to 30 years.

Capitalized Interest

We capitalize interest cost for qualifying construction and upgrade projects. During the three years ended December 31, 2016, we capitalized interest on qualifying expenditures, primarily related to our rig construction projects. See Note 9.

A reconciliation of our total interest cost to "Interest expense" as reported in our Consolidated Statements of Operations is as follows:

	For the Year Ended December 31,		
	2016	2015	2014
		(In thousands)	
Total interest cost including amortization of debt issuance costs	$110,748	$110,242	$122,656
Capitalized interest	(20,814)	(16,308)	(60,603)
Total interest expense as reported	$ 89,934	$ 93,934	$ 62,053

Impairment of Long-Lived Assets

We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable (such as, but not limited to, cold stacking a rig, the expectation of cold stacking a rig in the near term, contracted backlog of less than one year for a rig, a decision to retire or scrap a rig, or excess spending over budget on a newbuild, construction project or major rig upgrade). We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment. Our assumptions and estimates underlying this analysis include the following:

- dayrate by rig;
- utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);
- the per day operating cost for each rig if active, warm stacked or cold stacked;
- the estimated annual cost for rig replacements and/or enhancement programs;
- the estimated maintenance, inspection or other reactivation costs associated with a rig returning to work;
- salvage value for each rig; and
- estimated proceeds that may be received on disposition of each rig.

Based on these assumptions, we develop a matrix for each rig under evaluation using multiple utilization/dayrate scenarios, to each of which we have assigned a probability of occurrence. We arrive at a projected probability-weighted cash flow for each rig based on the respective matrix and compare such amount to the carrying value of the asset to assess recoverability.

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig's age, rated water depth and other attributes and then assesses its future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance, inspection and reactivation costs, are estimated using historical data adjusted for known developments, cost projections for re-entry of rigs into the market and future events that are anticipated by management at the time of the assessment.

Management's assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation, and the use of different assumptions could produce results that differ from those reported. Our methodology generally involves the use of significant unobservable inputs, representative of a Level 3 fair value measurement, which may include assumptions related to future dayrate revenue, costs and rig utilization, quotes from rig brokers, the long-term future performance of our rigs and future market conditions. Management's assumptions involve uncertainties about future demand for our services, dayrates, expenses and other future events, and management's expectations may not be indicative of future outcomes. Significant unanticipated changes to these assumptions could materially alter our analysis in testing an asset for potential impairment. For example, changes in market conditions that exist at the measurement date or that are projected by management could affect our key assumptions. Other events or circumstances that could affect our assumptions may include, but are not limited to, a further sustained decline in oil and gas prices, cancelations of our drilling contracts or contracts of our competitors, contract modifications, costs to comply with new governmental regulations, capital expenditures required due to advances in offshore drilling technology, growth in the global oversupply of oil and geopolitical events, such as lifting sanctions on oil-producing nations. Should actual market conditions in the future vary significantly from market conditions used in our projections, our assessment of impairment would likely be different. See Note 2.

Fair Value of Financial Instruments

We believe that the carrying amount of our current financial instruments approximates fair value because of the short maturity of these instruments. See Note 8.

Debt Issuance Costs

Historically, we have presented deferred costs associated with the issuance of long-term debt as "Other Assets" in our consolidated balance sheets and have amortized such costs over the respective terms of the related debt. In April 2015, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30); Simplifying the Presentation of Debt Issuance Costs, or ASU 2015-03, which requires debt issuance costs associated with our senior notes to be presented in the balance sheet as a reduction in the related long-term debt. We have adopted the provisions of ASU 2015-03 effective January 1, 2016 and have retrospectively applied its provisions to all periods presented in our Consolidated Financial Statements. The retrospective effect of our adoption of ASU 2015-03, which affected only the presentation of deferred debt issuance costs in our Consolidated Balance Sheets at December 31, 2015, is as follows:

	Other Assets	Long-term Debt
	(In thousands)	
Amount as previously presented, before adoption of ASU 2015-03	$116,480	$1,994,773
Deferred debt issuance costs	(14,995)	(14,995)
Amount as restated, after adoption of ASU 2015-03	$101,485	$1,979,778

See Note 10.

Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of the amount of taxes payable or refundable for the current year and 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 currently recognized in our financial statements or tax returns. In each of our tax jurisdictions we recognize a current tax liability or asset for the estimated taxes payable or refundable on tax returns for the current year and a deferred tax asset or liability for the estimated future tax effects attributable to temporary differences and carryforwards. Deferred tax assets are reduced by a valuation allowance, if necessary, which is determined by the amount of any tax benefits that, based on available evidence, are not expected to be realized under a "more likely than not" approach. Deferred tax assets and liabilities are classified as noncurrent in a classified statement of financial position. We make judgments regarding future events and related estimates especially as they pertain to the forecasting of our effective tax rate, the potential realization of deferred tax assets such as utilization of foreign tax credits, and exposure to the disallowance of items deducted on tax returns upon audit.

We record interest related to accrued unrecognized tax positions in "Interest expense, net of capitalized interest" and recognize penalties associated with uncertain tax positions in "Income tax benefit (expense)" in our Consolidated Statements of Operations. Liabilities for uncertain tax positions, including any penalty, are denominated in the currency of the related tax jurisdiction and are revalued for changes in currency exchange rates. The revaluation of such liabilities for uncertain tax positions is reported in "Income tax benefit (expense)" in our Consolidated Statements of Operations. See Note 16.

Treasury Stock

In connection with the vesting of restricted stock units held by our chief executive officer, or CEO, during 2016 and 2015, we acquired 7,923 and 7,810 shares of our common stock, respectively (valued at $0.2 million in each year) in satisfaction of tax withholding obligations that were incurred on the vesting date. See Note 3.

Depending on market conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We account for the purchase of treasury stock using the cost method, which reports the cost of the shares acquired in "Treasury stock" as a deduction from stockholders' equity in our Consolidated Balance Sheets. During the year ended December 31, 2014, we repurchased 1,895,561 shares of our outstanding common stock at a cost of $87.8 million. We did not repurchase any shares of our outstanding common stock during 2016 or 2015.

Comprehensive Income (Loss)

Comprehensive income (loss) is the change in equity of a business enterprise during a period from transactions and other events and circumstances except those transactions resulting from investments by owners and distributions to owners. Comprehensive income (loss) for the three years ended December 31, 2016, 2015 and 2014 includes net income (loss) and unrealized holding gains and losses on marketable securities and financial derivatives designated as cash flow accounting hedges. See Note 11.

Foreign Currency

Our functional currency is the U.S. dollar. Foreign currency transaction gains and losses are reported as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations and include, when applicable, unrealized gains and losses to record the carrying value of our FOREX contracts not designated as accounting hedges, as well as realized gains and losses from the settlement of such contracts. For the years ended December 31, 2016, 2015 and 2014, we recognized aggregate net foreign currency (losses) gains of $(11.5) million, $2.5 million and $3.2 million, respectively. See Note 7.

The revaluation of liabilities for uncertain tax positions, including any penalty, is reported in "Income tax benefit (expense)" in our Consolidated Statements of Operations. See Note 16.

Revenue Recognition

We recognize revenue from dayrate drilling contracts as services are performed. In connection with such drilling contracts, we may receive fees (on either a lump-sum or dayrate basis) for the mobilization of equipment. We earn these fees as services are performed over the initial term of the related drilling contracts. We defer mobilization fees received, as well as direct and incremental mobilization costs incurred, and amortize each, on a straight-line basis, over the term of the related drilling contracts (which is the period we estimate to be benefited from the mobilization activity). Straight-line amortization of mobilization revenues and related costs over the term of the related drilling contracts (which generally range from two to 60 months) is consistent with the timing of net cash flows generated from the actual drilling services performed. Absent a contract, mobilization costs are recognized currently. Upon completion of a drilling contract, we recognize in earnings any demobilization fees received and costs incurred.

Some of our drilling contracts require downtime before the start of the contract to prepare the rig to meet customer requirements. At times, we may be compensated by the customer for such work (on either a lump-sum or dayrate basis). These fees are generally earned as services are performed over the initial term of the related drilling contracts. We defer contract preparation fees received, as well as direct and incremental costs associated with the contract preparation activities and amortize each, on a straight-line basis, over the term of the related drilling contracts (which we estimate to be benefited from the contract preparation activity).

From time to time, we may receive fees from our customers for capital improvements to our rigs (on either a lump-sum or dayrate basis). We defer such fees received in “Accrued liabilities” and “Other liabilities” in our Consolidated Balance Sheets and recognize these fees into income on a straight-line basis over the period of the related drilling contract. We capitalize the costs of such capital improvements and depreciate them over the estimated useful life of the improvement.

We record reimbursements received for the purchase of supplies, equipment, personnel services and other services provided at the request of our customers in accordance with a contract or agreement, for the gross amount billed to the customer, as “Revenues related to reimbursable expenses” in our Consolidated Statements of Operations.

Recent Accounting Pronouncements

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*, or ASU 2016-15. ASU 2016-15 provides specific guidance on eight cash flow classification issues not specifically addressed by GAAP: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments; contingent consideration payments; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments in ASU 2016-15 are effective for interim and annual periods beginning after December 15, 2017. ASU 2016-15 should be applied using a retrospective transition method, unless it is impracticable to do so for some of the issues. In such case, the amendments for those issues would be applied prospectively as of the earliest date practicable. Early adoption is permitted. We are currently evaluating the provisions of ASU 2016-15 but do not expect ASU 2016-15 to have a significant impact on the presentation of cash receipts and cash payments within our consolidated statements of cash flows.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation - Stock Compensation (Topic 718)*, or ASU 2016-09, which simplifies several aspects of the accounting for share-based payment transactions. The new guidance makes several modifications to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. In addition, ASU 2016-09 clarifies the statement of cash flows presentation for certain components of share-based awards. The guidance of ASU 2016-09 is effective for interim and annual reporting periods beginning after December 15, 2016. We will adopt the provisions of ASU 2016-09 effective January 1, 2017. We do not expect the adoption of ASU 2016-09 to have a material impact on our financial position, results of operations or cash flows.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, or ASU 2016-02, which requires an entity to separate the lease components from the non-lease components in a contract. The lease components are to be accounted for under ASU 2016-02, which, under the guidance, may require recognition of lease assets and lease liabilities by lessees for most leases and derecognition of the leased asset and recognition of a net investment in the lease by the lessor. ASU 2016-02 also provides for additional disclosure requirements for both lessees and lessors. Non-lease components would be accounted for under ASU 2014-09. The guidance of ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period. Early adoption of ASU 2016-02 is permitted. We expect to adopt ASU 2016-02 on January 1, 2019. We are currently reviewing the provisions of the accounting standard, but have not yet determined the impact of ASU 2016-02 on our financial position, results of operations or cash flows or our expected transition method.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, or ASU 2014-09. The new standard supersedes the industry-specific standards that currently exist under GAAP and provides a framework to address revenue recognition issues comprehensively for all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Under the new guidance, companies 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. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized and requires enhanced disclosures about revenue. In July 2015, the FASB issued ASU 2015-14, which deferred the effective date of ASU 2014-09. ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017. We plan to adopt ASU 2014-09 effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018 as an adjustment to opening retained earnings. We do not expect our pattern of revenue recognition under the new guidance to materially differ from our current revenue recognition practice. We expect the cumulative effect adjustment to opening retained earnings to not be significant.

2. Asset Impairments

2016 Impairments — During 2016, in response to the continuing industry-wide decline in utilization for semisubmersible rigs, further exacerbated by additional and more frequent contract cancelations by customers, declining dayrates, as well as the results of a third-party strategic review of our long-term business plan completed in the second quarter of 2016, we reassessed our projections for a recovery in the offshore drilling market. As a result, we concluded that an expected market recovery is now likely further in the future than had previously been estimated. Consequently, we believe our cold-stacked rigs, as well as those rigs that we expect to cold stack in the near term after they come off contract, will likely remain cold stacked for an extended period of time. We also believe that the re-entry costs for these rigs will be higher than previously estimated, negatively impacting the undiscounted, probability-weighted cash flow projections utilized in our earlier impairment analysis. In addition, in response to the declining market, we have also reduced anticipated market pricing and expected utilization of these rigs after reactivation.

During 2016, we evaluated 15 of our drilling rigs with indications that their carrying amounts may not be recoverable. Based on our updated assumptions and analyses, we determined that the carrying values of eight of these rigs were impaired, including one rig that had been previously impaired in a prior year; (we collectively refer to these eight rigs as the “2016 Impaired Rigs”). The 2016 Impaired Rigs consisted of three ultra-deepwater, three deepwater and two mid-water semisubmersible rigs.

We estimated the fair value of the 2016 Impaired Rigs using an income approach. The fair value of each rig was estimated based on a calculation of the rig’s discounted future net cash flows over its remaining economic life, which utilized significant unobservable inputs, including, but not limited to, assumptions related to estimated dayrate revenue, rig utilization, estimated reactivation and regulatory survey costs, as well as estimated proceeds that may be received on ultimate disposition of the rig. Our fair value estimates were representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used. During the second quarter of 2016, we recorded an impairment loss of $670.0 million related to our 2016 Impaired Rigs.

2015 Impairments — During 2015, we evaluated 25 of our drilling rigs with indications that their carrying amounts may not be recoverable. Using an undiscounted, projected probability-weighted cash flow analysis, we determined that the carrying value of 17 of these rigs, consisting of two ultra-deepwater, one deepwater and nine mid-water floaters and five jack-up rigs, were impaired (we collectively refer to these 17 rigs as the "2015 Impaired Rigs").

We estimated the fair value of 16 of the 2015 Impaired Rigs utilizing a market approach, which required us to estimate the value that would be received for each rig in the principal or most advantageous market for that rig in an orderly transaction between market participants. Such estimates were based on various inputs, including historical contracted sales prices for similar rigs in our fleet, nonbinding quotes from rig brokers and/or indicative bids, where applicable. We estimated the fair value of the one remaining 2015 Impaired Rig using an income approach, as discussed above. Our fair value estimates are representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used.

During the first, third and fourth quarters of 2015, we recognized impairment losses of $358.5 million, $2.6 million and $499.4 million, respectively, for an aggregate impairment loss of $860.4 million for the year ended December 31, 2015.

2014 Impairments — During 2014, we initiated a plan to retire and scrap six mid-water drilling rigs. Using an undiscounted, projected probability-weighted cash flow analysis, we determined that the carrying values of these six rigs were impaired (we collectively refer to these six rigs as the "2014 Impaired Rigs"). We determined the fair value of the 2014 Impaired Rigs by applying a combination of income and market approaches which were representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used. As a result of our valuations, we recognized an impairment loss aggregating $109.5 million during the third quarter of 2014. No other impairment losses were recognized during 2014.

Of the 30 rigs impaired during the three-year period ended December 31, 2016, 20 rigs have been sold, and eight rigs are currently cold stacked. Two other previously impaired rigs are currently operating under contract.

If market fundamentals in the offshore oil and gas industry deteriorate further or if we are unable to secure new or extend contracts for our current, actively-marketed drilling fleet or reactivate any of our cold-stacked rigs or if we experience unfavorable changes to our actual dayrates and rig utilization, we may be required to recognize additional impairment losses in future periods, if we are unable to recover the carrying value of any of our drilling rigs.

See Notes 1 and 9.

3. Supplemental Financial Information

Consolidated Balance Sheet Information

Accounts receivable, net of allowance for bad debts, consists of the following:

	December 31,	
	2016	2015
	(In thousands)	
Trade receivables	$236,040	$390,429
Value added tax receivables	14,639	14,475
Amounts held in escrow	24	4,966
Interest receivable	9	336
Related party receivables	149	167
Other	1,626	721
	252,487	411,094
Allowance for bad debts	(5,459)	(5,724)
Total	$247,028	$405,370

An analysis of the changes in our provision for bad debts for each of the three years ended December 31, 2016, 2015 and 2014 is as follows:

	For the Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Allowance for bad debts, beginning of year	$5,724	$5,724	$ 27,340
Bad debt expense:			
Provision for bad debts	—	—	—
Recovery of bad debts	(265)	—	—
Total bad debt expense (recovery)	(265)	—	—
Write off of uncollectible accounts against reserve	—	—	(21,148)
Other (1)	—	—	(468)
Allowance for bad debts, end of year	$5,459	$5,724	$ 5,724

(1) Includes revaluation adjustments for non-U.S. dollar denominated receivables, which have been recorded as "Foreign currency transaction gain (loss)" in our Consolidated Statements of Operations.

See Note 8 for a discussion of our provision for bad debts and write off of uncollectible accounts against the reserve.

Prepaid expenses and other current assets consist of the following:

	December 31, 2016	December 31, 2015
	(In thousands)	
Rig spare parts and supplies	$ 25,343	$ 42,804
Deferred mobilization costs	61,488	52,965
Prepaid BOP Lease	3,873	—
Prepaid insurance	3,771	4,483
Prepaid taxes	2,894	14,969
Other	4,742	4,258
Total	$102,111	$119,479

During 2016, we recognized an $8.1 million impairment loss related to our rig spare parts and supplies.

Accrued liabilities consist of the following:

	December 31, 2016	December 31, 2015
	(In thousands)	
Rig operating expenses	$ 33,732	$ 47,426
Payroll and benefits	45,619	59,787
Deferred revenue	9,522	31,542
Accrued capital project/upgrade costs	60,308	84,146
Interest payable	18,365	18,365
Personal injury and other claims	6,424	8,320
Other	8,189	4,183
Total	$182,159	$253,769

Consolidated Statement of Cash Flows Information

Noncash investing activities excluded from the Consolidated Statements of Cash Flows and other supplemental cash flow information is as follows:

	December 31, 2016	December 31, 2015	December 31, 2014
		(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 60,308	$ 84,146	$103,123
Income tax benefits related to exercise of stock options	—	—	1,458
Common stock withheld for payroll tax obligations (1)	181	236	—
Cash interest payments (2)	105,987	110,412	133,784
Cash income taxes paid (refunded), net:			
U.S. federal	(31,151)	(21,751)	—
Foreign	48,931	69,697	92,049
State	1	58	(18)

(1) Represents the cost of 7,923 and 7,810 shares of common stock withheld to satisfy the payroll tax obligation incurred as a result of the vesting of restricted stock units in 2016 and 2015, respectively. These costs are presented as a

deduction from stockholders' equity in "Treasury stock" in our Consolidated Balance Sheets at December 31, 2016 and 2015.

(2) Interest payments, net of amounts capitalized, were $86.1 million, $94.7 million and $73.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

4. Stock-Based Compensation

We have an Equity Incentive Compensation Plan, or Equity Plan, for our (a) officers (b) independent contractors, (c) employees and (d) non-employee directors, which is designed to encourage stock ownership by such persons, thereby aligning their interests with those of our stockholders and to permit the payment of performance-based compensation as defined by the Internal Revenue Code of 1986, as amended, or the Code. Under the Equity Plan, we may grant both time-vesting and performance-vesting awards, which are earned on the achievement of certain performance criteria. The following types of awards may be granted under the Equity Plan:

- Stock options (including incentive stock options and nonqualified stock options);
- Stock appreciation rights, or SARs;
- Restricted stock;
- Restricted stock units, or RSUs;
- Performance shares or units; and
- Other stock-based awards (including dividend equivalents).

A maximum of 7,500,000 shares of our common stock is available for the grant or settlement of awards under the Equity Plan, subject to adjustment for certain business transactions and changes in capital structure. Vesting conditions and other terms and conditions of awards under the Equity Plan are determined by our Board of Directors or the compensation committee of our Board of Directors, subject to the terms of the Equity Plan. RSUs may be issued with performance-vesting or time-vesting features. Except for RSUs issued to our CEO, RSUs are not participating securities, and the holders of such awards have no right to receive regular dividends if or when declared.

Total compensation cost recognized for all awards under the Equity Plan (or its predecessor) for the years ended December 31, 2016, 2015 and 2014 was $7.0 million, $5.7 million and $5.0 million, respectively. Tax benefits recognized for the years ended December 31, 2016, 2015 and 2014 related thereto were $2.4 million, $1.9 million and $1.4 million, respectively. As of December 31, 2016 there was $11.8 million of total unrecognized compensation cost related to non-vested awards under the Equity Plan, which we expect to recognize over a weighted average period of two years.

Time-Vesting Awards

SARs. SARs awarded under the Equity Plan generally vest ratably over a four-year period and expire in ten years. The exercise price per share of SARs awarded under the Equity Plan may not be less than the fair market value of our common stock on the date of grant.

The fair value of SARs granted under the Equity Plan (or its predecessor) during each of the years ended December 31, 2016, 2015 and 2014 was estimated using the Black Scholes pricing model with the following weighted average assumptions:

	Year Ended December 31, 2016	2015	2014
Expected life of SARs (in years)	7	6	7
Expected volatility	45.79%	55.12%	21.68%
Dividend yield	.60%[1]	1.70%	1.10%
Risk free interest rate	1.46%	1.66%	2.08%

(1) Represents dividend yield related to January 2016 grant of SARs prior to our decision in early 2016 to discontinue paying dividends.

The expected life of SARs is based on historical data as is the expected volatility. The dividend yield is based on the current approved regular dividend rate in effect and the current market price at the time of grant. Risk free interest rates are determined using the U.S. Treasury yield curve at time of grant with a term equal to the expected life of the SARs.

A summary of SARs activity under the Equity Plan as of December 31, 2016 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (In Thousands)
Awards outstanding at January 1, 2016	1,531,631	$70.26		
Granted	66,000	$21.04		
Exercised	—			
Forfeited	10,196	$49.48		
Expired	137,729	$78.01		
Awards outstanding at December 31, 2016	1,449,706	$67.43	5.0	$3
Awards exercisable at December 31, 2016	1,347,992	$68.88	4.9	$3

The weighted-average grant date fair values per share of awards granted during the years ended December 31, 2016, 2015 and 2014 were $9.32, $14.44 and $10.40, respectively. The total intrinsic value of awards exercised during the years ended December 31, 2016, 2015 and 2014 was $0, $0 and $169,000, respectively. The total fair value of awards vested during the years ended December 31, 2016, 2015 and 2014 was $2.2 million, $3.6 million and $4.5 million, respectively.

Restricted Stock Units. RSUs are contractual rights to receive shares of our common stock in the future if the applicable vesting conditions are met. On April 1, 2016 and 2015, we granted an aggregate of 183,076 and 153,493 time-vesting RSUs, respectively. One-half of each annual grant will vest two years from the date of grant and the remaining 50% of which will vest three years from the date of grant, conditioned upon continued employment through the applicable vesting date. The fair value of time-vesting RSUs granted under the Equity Plan was estimated based on the fair market value of our common stock on the date of grant. The fair value of non-participating RSUs granted in 2015 were discounted at a three-year risk-free interest rate of 1.48%, in consideration of the non-participative rights of the awards. The fair value of non-participating RSUs granted in 2016 was not discounted as the fair value would have reflected the 2016 suspension of regular dividend payments.

A summary of activity for time-vesting RSUs under the Equity Plan as of December 31, 2016 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Grant Date Fair Value Per Share
Nonvested awards at January 1, 2016	149,614	$25.09
Granted	183,076	$21.61
Vested	—	$ —
Forfeited	13,130	$24.21
Nonvested awards at December 31, 2016	319,560	$23.13

No time-vesting RSUs vested during the years ended December 31, 2016 or 2015.

Performance-Vesting Awards

Restricted Stock Units. On April 1, 2016 and 2015, we granted an aggregate 248,188 and 169,312 performance-vesting RSUs, respectively, which will vest upon achievement of certain performance goals as set forth in the individual award agreements over the three-year performance period beginning on January 1 in the year of grant and ending on December 31 of the third year following the date of grant. The shares of our common stock to be received upon the vesting of the performance-vesting RSUs will be delivered no later than March 15 of the year following completion of the three-year performance period. The fair value of performance-vesting RSUs granted under the Equity Plan to employees in 2015, other than to our CEO, was estimated based on the fair market value of our common stock on the date of grant. The fair value of non-participating, performance-vesting RSUs granted in 2015 was discounted at a three-year risk-free interest rate of 1.48% in consideration of the non-participative rights of the awards. The fair value of performance-vesting RSUs granted to our CEO in 2015 was not discounted as such awards are participating securities. The fair value of performance-vesting RSUs granted in 2016 were not discounted as the fair value would have reflected the 2016 suspension of regular dividend payments.

In 2014, we awarded 55,661 targeted performance RSUs, with a volume weighted average price of our common stock preceding the grant date of $46.99 per share, including 3,080 in RSUs credited upon payment of cash dividends in 2014, to our CEO in connection with his commencement of service with us in March 2014. The RSUs awarded to our CEO in 2014 vest in one-third increments annually, over three years, commencing on the first anniversary of his hire date, conditioned upon continued employment through the applicable vesting date.

A summary of activity for performance-vesting RSUs under the Equity Plan as of December 31, 2016 and changes during the year then ended is as follows:

	Number of Awards	Weighted-Average Grant Date Fair Value Per Share
Nonvested awards at January 1, 2016	206,356	$29.93
Granted	248,188	$21.75
Vested	18,880	$46.64
Forfeited	3,958	$23.97
Nonvested awards at December 31, 2016	431,706	$24.55

The total grant date fair value of the performance-vesting RSUs that vested during the years ended December 31, 2016, 2015 and 2014 was $0.4 million, $0.6 million and $0, respectively.

5. Earnings Per Share

A reconciliation of the numerators and the denominators of the basic and diluted per-share computations follows:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except per share data)		
Net (loss) income — basic and diluted (numerator):	$(372,503)	$(274,285)	$387,011
Weighted-average shares — basic (denominator):	137,168	137,157	137,473
Dilutive effect of stock-based awards	—	—	50
Weighted-average shares including conversions — diluted (denominator):	137,168	137,157	137,523
(Loss) earnings per share:			
Basic	$ (2.72)	$ (2.00)	$ 2.82
Diluted	$ (2.72)	$ (2.00)	$ 2.81

The following table sets forth the share effects of stock-based awards excluded from our computations of diluted earnings per share, or EPS, as the inclusion of such potentially dilutive shares would have been antidilutive for the periods presented:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Employee and director:			
Stock options	7	26	37
SARs	1,505	1,553	1,488
RSUs	704	278	—

6. Marketable Securities

We report our investments in marketable securities as current assets in our Consolidated Balance Sheets in "Marketable securities," representing the investment of cash available for current operations. See Note 8.

Our investments in marketable securities are classified as available for sale and are summarized as follows:

	December 31, 2016		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
	(In thousands)		
Mortgage-backed securities	$35	$—	$35

	December 31, 2015		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
	(In thousands)		
Corporate bonds	$16,480	$(5,042)	$11,438
Mortgage-backed securities	77	3	80
Total	$16,557	$(5,039)	$11,518

Proceeds from maturities and sales of marketable securities and gross realized gains and losses are summarized as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Proceeds from maturities	$ —	$—	$8,000,000
Proceeds from sales	4,614	51	57

During 2016, we sold an investment in corporate bonds for proceeds of $4.6 million and recognized a loss of $12.9 million. Gross realized gains and losses from the sale of mortgage-backed securities for each of the three years ended December 31, 2016, 2015 and 2014 were not significant.

7. Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

Our international operations expose us to foreign exchange risk associated with our costs payable in foreign currencies. To manage this risk, we entered into FOREX contracts in past years for future delivery of Australian dollars, Brazilian reais, British pounds sterling, Mexican pesos and Norwegian kroner. These forward contracts were derivatives as defined by GAAP.

During the years ended December 31, 2015 and 2014, we settled FOREX contracts with aggregate notional values of approximately $91.6 million and $304.7 million, respectively, of which the entire aggregate amounts were designated as an accounting hedge. During the years ended December 31, 2015 and 2014, we did not enter into or settle any FOREX contracts that were not designated as accounting hedges. We did not enter into any FOREX contracts during 2016. There were no FOREX contracts outstanding at December 31, 2016 or 2015.

During the years ended December 31, 2015 and 2014, we recognized an aggregate gain (loss) of $(8.4) million and $3.3 million, respectively, related to our FOREX contracts designated as hedging instruments, which was reported in Contract drilling expense in our Consolidated Statements of Operations.

The following table presents the amounts recognized in our Consolidated Balance Sheets and Consolidated Statements of Operations related to our derivative financial instruments designated as cash flow hedges for the years ended December 31, 2015 and 2014.

	For the Year Ended December 31,	
	2015	2014
	(In thousands)	
FOREX contracts:		
Amount of loss recognized in AOCGL on derivative (effective portion)	$ (2,420)	$ (2,281)
Location of (loss) gain reclassified from AOCGL into income (effective portion)	Contract drilling, excluding depreciation	Contract drilling, excluding depreciation
Amount of (loss) gain reclassified from AOCGL into income (effective portion)	$ (7,829)	$ 3,650
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction gain (loss)	Foreign currency transaction gain (loss)
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$ (1)	$ (31)

During the years ended December 31, 2015 and 2014, we did not reclassify any amounts from AOCGL due to the probability of an underlying forecasted transaction not occurring.

8. Financial Instruments and Fair Value Disclosures

Concentrations of Credit and Market Risk

Financial instruments that potentially subject us to significant concentrations of credit or market risk consist primarily of periodic temporary investments of excess cash, trade accounts receivable and investments in debt securities, including mortgage-backed securities. We generally place our excess cash investments in U.S. government backed short-term money market instruments through several financial institutions. At times, such investments may be in excess of the insurable limit. We periodically evaluate the relative credit standing of these financial institutions as part of our investment strategy.

Concentrations of credit risk with respect to our trade accounts receivable are limited primarily due to the entities comprising our customer base. Since the market for our services is the offshore oil and gas industry, this customer base consists primarily of major and independent oil and gas companies and government-owned oil companies. Based on our current customer base and the geographic areas in which we operate, as well as the number of rigs currently working in a geographic area, we do not believe that we have any significant concentrations of credit risk at December 31, 2016.

In general, before working for a customer with whom we have not had a prior business relationship and/or whose financial stability may be uncertain to us, we perform a credit review on that company. Based on that analysis, we may require that the customer present a letter of credit, prepay or provide other credit enhancements. We record a provision for bad debts on a case-by-case basis when facts and circumstances indicate that a customer receivable may not be collectible and, historically, losses on our trade receivables have been infrequent occurrences.

During 2013, based on our assessment of the financial condition of two of our customers, Niko Resources Ltd., or Niko, and OGX Petróleo e Gás Ltda. (a privately owned Brazilian oil and natural gas company that filed for bankruptcy in

October 2013), or OGX, and our expectations at the time regarding the probability of collection of amounts due to us from them, we recorded $22.5 million in bad debt expense to fully reserve all outstanding receivables owed to us.

In December 2013, we entered into a settlement with Niko with respect to certain obligations under dayrate contracts for the Ocean Monarch and Ocean Lexington, whereby, we would receive an aggregate $80.0 million. From December 2013 until their default on the agreement, we received $49.0 million from Niko. Commencing in 2015, we filed suit against Niko in the U.S. and Canadian courts, both of which granted judgments against Niko. On October 18, 2016, we executed a final settlement agreement with Niko, or the 2016 Agreement. Under the 2016 Agreement, Niko paid a cash settlement amount of $3.0 million, agreed to make future payments to us equal to 20% of amounts to be retained by Niko pursuant to a waterfall distribution under their credit facility and assigned to us Niko’s interest in potential contingent payments related to the sale of five Indonesian production sharing contracts. We plan to recognize these amounts in revenue as they are received due to the uncertainty regarding their timing and collection. As of December 31, 2016, the amount outstanding under the agreement was $28.0 million.

In 2014, the creditors of OGX, including us, agreed to a settlement whereby the creditors granted us shares of the reorganized OGX company in full settlement of obligations owed to them by OGX. As a result of the settlement, we have written off $21.2 million in receivables due us from OGX against the associated allowance for bad debts, which was established in 2013. See Note 3.

Fair Values

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy prescribed by GAAP requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. There are three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices for identical instruments in active markets. Level 1 assets include short-term investments such as money market funds, U.S. Treasury Bills and Treasury notes. Our Level 1 assets at December 31, 2016 consisted of cash held in money market funds of $125.7 million and time deposits of $20.6 million. Our Level 1 assets at December 31, 2015 consisted of cash held in money market funds of $85.2 million and time deposits of $20.4 million.

Level 2 Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities may include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter FOREX contracts. Our residential mortgage-backed securities and corporate bonds, prior to being sold in the second quarter of 2016, were valued using a model-derived valuation technique based on the quoted closing market prices received from a financial institution. The valuation techniques underlying the models are widely accepted in the financial services industry and do not involve significant judgment.

Level 3 Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used. Our Level 3 assets at December 31, 2016 and 2015 consisted of nonrecurring measurements of certain of our drilling rigs and associated spare parts and supplies for which we recorded an impairment loss during the second quarter of 2016 and the year ended December 31, 2015. See Notes 1, 2 and 3.

Market conditions could cause an instrument to be reclassified among Levels 1, 2 and 3. Our policy regarding fair value measurements of financial instruments transferred into and out of levels is to reflect the transfers as having occurred at the beginning of the reporting period. There were no transfers between fair value levels during the years ended December 31, 2016 and 2015.

Certain of our assets and liabilities are required to be measured at fair value on a recurring basis in accordance with GAAP. In addition, certain assets and liabilities may be recorded at fair value on a nonrecurring basis. Generally, we record assets at fair value on a nonrecurring basis as a result of impairment charges. We recorded impairment charges related to certain of our drilling rigs and related spare parts and supplies, which were measured at fair value on a nonrecurring basis in 2016 and 2015, respectively, and have presented the aggregate loss in “Impairment of assets” in our Consolidated Statements of Operations for the years ended December 31, 2016 and 2015.

	December 31, 2016				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended (1)
	Level 1	Level 2	Level 3		
	(In thousands)				
Recurring fair value measurements:					
Assets:					
Short-term investments	$146,360	$—	$ —	$146,360	
Mortgage-backed securities	—	35	—	35	
Total assets	$146,360	$35	$ —	$146,395	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets (2)(3)	$ —	$—	$69,153	$ 69,153	$678,145

(1) Represents impairment losses of $8.1 million and $670.0 million recognized during the year ended December 31, 2016 related to our rig spare parts and supplies and 2016 Impaired Rigs, respectively. See Notes 2 and 3.

(2) Represents the total book value as of December 31, 2016 for 11 drilling rigs ($45.5 million), which were written down to their estimated recoverable amounts in 2015 and 2016, and for rig spare parts and supplies ($23.6 million), which were written down to their estimated recoverable amounts in the second quarter of 2016. Of the total fair value, $23.6 million, $0.4 million and $45.1 million were reported as “Prepaid expenses and other current assets,” “Assets held for sale” and “Drilling and other property and equipment, net of accumulated depreciation,” respectively, in our Consolidated Balance Sheets at December 31, 2016. See Notes 1, 2 and 3.

(3) Includes depreciation expense of $23.9 million recognized during the year ended December 31, 2016 for rigs which have previously been written down to their estimated fair values using an income approach. Also excludes four jack-up rigs, three mid-water semisubmersible rigs and one deepwater semisubmersible rig with an aggregate fair value of $16.0 million, which have been sold.

	December 31, 2015				
	Fair Value Measurements Using			Assets at Fair Value	Total Losses for Year Ended (1)
	Level 1	Level 2	Level 3		
	(In thousands)				
Recurring fair value measurements:					
Assets:					
Short-term investments	$105,659	$ —	$ —	$105,659	
Corporate bonds	—	11,438	—	11,438	
Mortgage-backed securities	—	80	—	80	
Total assets	$105,659	$11,518	$ —	$117,177	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets (2)(3)	$ —	$ —	$189,600	$189,600	$860,441

(1) Represents the aggregate impairment loss recognized for the year ended December 31, 2015 related to our 2015 Impaired Rigs.

(2) Represents the book value of our 2015 Impaired Rigs, which were written down to their estimated recoverable amounts during 2015, of which $14.2 million and $175.4 million were reported as “Assets held for sale” and “Drilling and other property and equipment, net of accumulated depreciation,” respectively, in our Consolidated Balance Sheets at December 31, 2015.

(3) Excludes five rigs with an aggregate fair value of $2.4 million, which were impaired in 2015, but were subsequently sold for scrap during the year.

We believe that the carrying amounts of our other financial assets and liabilities (excluding long-term debt), which are not measured at fair value in our Consolidated Balance Sheets, approximate fair value based on the following assumptions:

- *Cash and cash equivalents* — The carrying amounts approximate fair value because of the short maturity of these instruments.

- *Accounts receivable and accounts payable* — The carrying amounts approximate fair value based on the nature of the instruments.

- *Short-term borrowings* — The carrying amounts approximate fair value because of the short maturity of these instruments.

We consider our senior notes, including current maturities, to be Level 2 liabilities under the GAAP fair value hierarchy and, accordingly, the fair value of our senior notes was derived using a third-party pricing service at December 31, 2016 and 2015. We perform control procedures over information we obtain from pricing services and brokers to test whether prices received represent a reasonable estimate of fair value. These procedures include the review of pricing service or broker pricing methodologies and comparing fair value estimates to actual trade activity executed in the market for these instruments occurring generally within a 10-day window of the report date. Fair values and related carrying values of our senior notes (see Note 10) are shown below.

	December 31, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.875% Senior Notes due 2019	$518.6	$499.8	$506.8	$499.7
3.45% Senior Notes due 2023	215.0	249.3	208.0	249.2
5.70% Senior Notes due 2039	392.5	497.1	360.0	497.0
4.875% Senior Notes due 2043	532.7	748.9	455.3	748.9

We have estimated the fair value amounts by using appropriate valuation methodologies and information available to management. Considerable judgment is required in developing these estimates, and accordingly, no assurance can be given that the estimated values are indicative of the amounts that would be realized in a free market exchange.

9. Drilling and Other Property and Equipment

Cost and accumulated depreciation of drilling and other property and equipment are summarized as follows:

	December 31,	
	2016	2015
	(In thousands)	
Drilling rigs and equipment	$ 8,950,385	$ 9,345,484
Construction work-in-progress	—	269,605
Land and buildings	64,449	64,775
Office equipment and other	73,108	71,537
Cost	9,087,942	9,751,401
Less accumulated depreciation	(3,361,007)	(3,372,587)
Drilling and other property and equipment, net	$ 5,726,935	$ 6,378,814

During the year ended December 31, 2016, we recognized an impairment loss of $670.0 million. See Note 2.

Our harsh environment, ultra-deepwater semisubmersible rig, *Ocean GreatWhite*, reported as construction work-in-progress at December 31, 2015, was placed in service in December 2016.

10. Credit Agreement, Commercial Paper and Senior Notes

Credit Agreement

We have a syndicated revolving credit agreement with Wells Fargo Bank, National Association, as administrative agent and swingline lender, which provides for a $1.5 billion senior unsecured revolving credit facility for general corporate purposes, or the Credit Agreement. Our Credit Agreement matures on October 22, 2020, except for $40 million of commitments that mature on March 17, 2019 and $60 million of commitments that mature on October 22, 2019. In addition, we also have the option to increase the revolving commitments under the Credit Agreement by up to an additional $500 million from time to time, upon receipt of additional commitments from new or existing lenders, and to request one additional one-year extension of the maturity date. The entire amount of the facility is available, subject to its terms, for revolving loans. Up to $250 million of the facility may be used for the issuance of performance or other standby letters of credit and up to $100 million may be used for swingline loans.

Revolving loans under the Credit Agreement bear interest, at our option, at a rate per annum based on either an alternate base rate, or ABR, or a Eurodollar Rate, as defined in the Credit Agreement, plus the applicable interest margin for an ABR loan or a Eurodollar loan. Based on our current credit ratings, the applicable interest rate for ABR loans under the Credit Agreement is 0.25% over the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the daily one-month Eurodollar Rate plus 1.00%. The applicable interest rate for Eurodollar loans under the Credit Agreement is currently 1.25% over British Bankers' Association LIBOR.

Swingline loans bear interest, at our option, at a rate per annum equal to (i) the ABR plus the applicable interest margin for ABR loans or (ii) the daily one-month Eurodollar Rate plus the applicable interest margin for Eurodollar loans.

Under our Credit Agreement, we also pay, based on our current long-term credit ratings, and as applicable, other customary fees including, but not limited to, a commitment fee on the unused commitments under the Credit Agreement, varying between 0.06% and 0.20% per annum, and a fronting fee to the issuing bank for each letter of credit. Participation fees for letters of credit are dependent upon the type of letter of credit issued, varying between 0.375% and 0.625% per annum for performance letters of credit, and between 0.75% and 1.25% per annum for all other letters of credit. Based on our current credit ratings, the applicable commitment fee is 0.20%, and the participation fee for letters of credit is 0.625%. Favorable changes in our current credit ratings could lower the fees that we pay under the Credit Agreement; however, any further downgrade in our credit ratings would have no further impact on the applicable interest rates and fees.

The Credit Agreement contains customary covenants including, but not limited to, maintenance of a ratio of consolidated indebtedness to total capitalization, as defined in the Credit Agreement, of not more than 60% at the end of each fiscal quarter, as well as limitations on liens; mergers, consolidations, liquidation and dissolution; changes in lines of business; swap agreements; transactions with affiliates; and subsidiary indebtedness. As of December 31, 2016, we were in compliance with all covenant requirements.

At December 31, 2016, we had $104.2 million in borrowings outstanding under the Credit Agreement. These borrowings bore interest at a weighted average interest rate of 1.9%. As of February 10, 2017, we had no borrowings outstanding under the Credit Agreement and an additional $1.5 billion available. There were no amounts outstanding under the Credit Agreement at December 31, 2015.

Commercial Paper

In January 2016, we repaid $286.6 million in commercial paper notes outstanding at December 31, 2015 with proceeds from borrowings under the Credit Agreement. We subsequently canceled our commercial paper program in the first quarter of 2016 as a result of a downgrade of our short-term credit rating to sub-prime by Moody's Investors Service and our expectation that we would be unable to access the commercial paper market in the foreseeable future.

Senior Notes

At December 31, 2016, our senior notes were comprised of the following debt issues:

Debt Issue	Principal Amount (In millions)	Maturity Date	Interest Rate Coupon	Interest Rate Effective	Semiannual Interest Payment Dates
5.875% Senior Notes due 2019	$500.0	May 1, 2019	5.875%	5.89%	May 1 and November 1
3.45% Senior Notes due 2023	$250.0	November 1, 2023	3.45%	3.50%	May 1 and November 1
5.70% Senior Notes due 2039	$500.0	October 15, 2039	5.70%	5.75%	April 15 and October 15
4.875% Senior Notes due 2043	$750.0	November 1, 2043	4.875%	4.89%	May 1 and November 1

At December 31, 2016 and 2015, the carrying value of our senior notes, net of unamortized discount and debt issuance costs, was as follows:

	December 31, 2016	December 31, 2015
	(In thousands)	
5.875% Senior Notes due 2019	$ 498,679	$ 498,146
3.45% Senior Notes due 2023	247,879	247,605
5.70% Senior Notes due 2039	492,812	492,663
4.875% Senior Notes due 2043	741,514	741,364
Total senior notes, net	$1,980,884	$1,979,778

As of December 31, 2016, the aggregate annual maturity of our senior notes, excluding net unamortized discounts and debt issuance costs of $5.0 million and $14.1 million, respectively, was as follows:

	Aggregate Principal Amount (In thousands)
Year Ending December 31,	
2017	$ —
2018	—
2019	500,000
2020	—
2021	—
Thereafter	1,500,000
Total maturities of senior notes	$2,000,000

Senior Notes Due 2023 and 2043. Our 3.45% Senior Notes due 2023 and 4.875% Senior Notes due 2043 are unsecured and unsubordinated obligations of Diamond Offshore Drilling, Inc., and rank equally in right of payment to all of its existing and future unsecured and unsubordinated indebtedness, and are effectively subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem all or a portion of the Senior Notes Due 2023 and 2043 for cash at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at a make-whole redemption price specified in the governing indenture (if applicable) plus accrued and unpaid interest to, but excluding, the date of redemption.

Senior Notes Due 2019 and 2039. Our 5.875% Senior Notes due 2019 and 5.70% Senior Notes due 2039 are unsecured and unsubordinated obligations of Diamond Offshore Drilling, Inc. and rank equally in right of payment to its existing and future unsecured and unsubordinated indebtedness, and are effectively subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem all or a portion of these notes for cash at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at the redemption price specified in the governing indenture plus accrued and unpaid interest to the date of redemption.

11. Other Comprehensive Income (Loss)

The following table sets forth the components of "Other comprehensive gain (loss)" and the related income tax effects thereon for the three years ended December 31, 2016 and the cumulative balances in AOCGL by component at December 31, 2016, 2015 and 2014.

	Unrealized Gain (Loss) on		
	Derivative Financial Instruments	Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2014	$ 357	$ (7)	$ 350
Change in other comprehensive loss before reclassifications, after tax of $799 and $(15)	(1,482)	(69)	(1,551)
Reclassification adjustments for items included in Net Income, after tax of $1,279 and $7	(2,379)	(25)	(2,404)
Total other comprehensive (loss)	(3,861)	(94)	(3,955)
Balance at December 31, 2014	(3,504)	(101)	(3,605)
Change in other comprehensive loss before reclassifications, after tax of $846 and $(1)	(1,574)	(4,940)	(6,514)
Reclassification adjustments for items included in Net Income, after tax of $(2,737) and $0	5,084	—	5,084
Total other comprehensive income (loss)	3,510	(4,940)	(1,430)
Balance at December 31, 2015	6	(5,041)	(5,035)
Change in other comprehensive loss before reclassifications, after tax of $0 and $2	—	(6,559)	(6,559)
Reclassification adjustments for items included in Net Loss, after tax of $3 and $0	(5)	11,600	11,595
Total other comprehensive (loss) income	(5)	5,041	5,036
Balance at December 31, 2016	$ 1	$ —	$ 1

The following table presents the line items in our Consolidated Statements of Operations affected by reclassification adjustments out of AOCGL.

Major Components of AOCGL	Year Ended December 31, 2016	2015 (In thousands)	2014	Consolidated Statements of Operations Line Items
Derivative financial instruments:				
Unrealized loss (gain) on FOREX contracts	$ —	$ 7,829	$(3,650)	Contract drilling, excluding depreciation
Unrealized gain on Treasury Lock Agreements	(8)	(8)	(8)	Interest expense
	3	(2,737)	1,279	Income tax expense (benefit)
	$ (5)	$ 5,084	$(2,379)	Net of tax
Marketable securities:				
Unrealized loss (gain) on marketable securities	$11,600	$ —	$ (32)	Other, net
	—	—	7	Income tax expense
	$11,600	$ —	$ (25)	Net of tax

12. Commitments and Contingencies

Various claims have been filed against us in the ordinary course of business, including claims by offshore workers alleging personal injuries. With respect to each claim or exposure, we have made an assessment, in accordance with GAAP, of the probability that the resolution of the matter would ultimately result in a loss. When we determine that an unfavorable resolution of a matter is probable and such amount of loss can be determined, we record a liability for the amount of the estimated loss at the time that both of these criteria are met. Our management believes that we have recorded adequate accruals for any liabilities that may reasonably be expected to result from these claims.

Asbestos Litigation. We are one of several unrelated defendants in lawsuits filed in Louisiana state courts alleging that defendants manufactured, distributed or utilized drilling mud containing asbestos and, in our case, allowed such drilling mud to have been utilized aboard our drilling rigs. The plaintiffs seek, among other things, an award of unspecified compensatory and punitive damages. The manufacture and use of asbestos-containing drilling mud had already ceased before we acquired any of the drilling rigs addressed in these lawsuits. We believe that we are not liable for the damages asserted in the lawsuits pursuant to the terms of our 1989 asset purchase agreement with Diamond M Corporation. We are unable to estimate our potential exposure, if any, to these lawsuits at this time but do not believe that our ultimate liability, if any, resulting from this litigation will have a material effect on our consolidated financial condition, results of operations or cash flows.

Other Litigation. We have been named in various other claims, lawsuits or threatened actions that are incidental to the ordinary course of our business, including a claim by Petrobras that it will seek to recover from its contractors, including us, any taxes, penalties, interest and fees that it must pay to the Brazilian tax authorities for our applicable portion of withholding taxes related to Petrobras' charter agreements with its contractors. We intend to defend these matters vigorously; however, litigation is inherently unpredictable, and the ultimate outcome or effect of these claims, lawsuits and actions cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of these matters. Any claims against us, whether meritorious or not, could cause us to incur costs and expenses, require significant amounts of management time and result in the diversion of significant operational resources. In the opinion of our management, no pending or known threatened claims, actions or proceedings against us are expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

NPI Arrangement. We received customer payments measured by a percentage net profits interest (primarily of 27%) under an overriding royalty interest in certain developmental oil-and-gas producing properties, or NPI, which we believe is a real property interest. Our drilling program related to the NPI was completed in 2011, and the balance of the amounts due to us under the NPI was received in 2013. However, in August 2012, the customer that conveyed the NPI to us filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code. Certain parties (including the debtor) in the bankruptcy proceedings questioned whether our NPI, and certain amounts we received under it after the filing of the bankruptcy, should be included in the debtor's estate under the bankruptcy proceeding. In 2013, we filed a declaratory judgment action in the bankruptcy court seeking a declaration that our NPI, and payments that we received from it after the filing of the bankruptcy, are not part of the bankruptcy estate. We agreed to a settlement with the company that purchased most of the debtor's assets (including the debtor's claims against our NPI) whereby the nature of our NPI will not be challenged by that party and our declaratory judgment action was dismissed. Following the settlement, the bankruptcy was converted to a Chapter 7 liquidation proceeding. Several lienholders who had previously intervened in the declaratory judgment action filed motions in the bankruptcy contending that their liens have priority and seeking disgorgement of $3.25 million of payments made to us after the bankruptcy was filed. We believe that our rights to the payments at issue are superior to these liens, and we filed motions to dismiss the claims. In November 2016, the court dismissed the lienholders' claims, and the lienholders are appealing the ruling. In addition, the bankruptcy trustee filed counterclaims seeking disgorgement of a total of $30.0 million of pre- and post-bankruptcy payments made to us under the original NPI. The bankruptcy court has dismissed all but one of the trustee's disgorgement claims, which is limited in amount to $17.0 million. In December 2016, the company that purchased most of the debtor's assets from bankruptcy also filed for bankruptcy. We continue to pursue all available defenses and available protections, and still expect the bankruptcy proceedings to be concluded with no further material impact to us.

Personal Injury Claims. Under our current insurance policies, which renewed effective May 1, 2016, our deductibles for marine liability insurance coverage with respect to personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, which primarily result from Jones Act liability in the Gulf of Mexico, are $10.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductible for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

The Jones Act is a federal law that permits seamen to seek compensation for certain injuries during the course of their employment on a vessel and governs the liability of vessel operators and marine employers for the work-related injury or death of an employee. We engage outside consultants to assist us in estimating our aggregate liability for personal injury claims based on our historical losses and utilizing various actuarial models. We allocate a portion of the aggregate liability to "Accrued liabilities" based on an estimate of claims expected to be paid within the next twelve months with the residual recorded as "Other liabilities." At December 31, 2016 our estimated liability for personal injury claims was $32.9 million, of which $6.1 million and $26.8 million were recorded in "Accrued liabilities" and "Other liabilities," respectively, in our Consolidated Balance Sheets. At December 31, 2015 our estimated liability for personal injury claims was $40.4 million, of which $8.2 million and $32.2 million were recorded in "Accrued liabilities" and "Other liabilities," respectively, in our Consolidated Balance Sheets. The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

- the severity of personal injuries claimed;

- significant changes in the volume of personal injury claims;
- the unpredictability of legal jurisdictions where the claims will ultimately be litigated;
- inconsistent court decisions; and
- the risks and lack of predictability inherent in personal injury litigation.

Purchase Obligations. At December 31, 2016, we had no purchase obligations for major rig upgrades or any other significant obligations, except for those related to our direct rig operations, which arise during the normal course of business.

Operating Leases. We lease office and yard facilities, housing, non-rig equipment and vehicles under operating leases, which expire at various times through the year 2022. Total rent expense amounted to $5.5 million, $7.8 million and $10.6 million for the years ended December 31, 2016, 2015 and 2014, respectively. Future minimum rental payments under leases are approximately $1.8 million and $0.5 million for 2017 and 2018, respectively, $0.1 million for each of the years 2019 through 2021 and $32,000 thereafter.

In addition, we lease certain blowout preventer, or BOP, and related well control equipment under ten-year operating leases. See Note 13.

Letters of Credit and Other. We were contingently liable as of December 31, 2016 in the amount of $57.2 million under certain performance, supersedeas, tax, court and customs bonds and letters of credit. Agreements relating to approximately $53.9 million of performance, tax, supersedeas, court and customs bonds can require collateral at any time. As of December 31, 2016, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. On our behalf, banks have issued letters of credit securing certain of these bonds.

13. Sale and Leaseback Transactions

In February 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide services with respect to certain blowout preventer and related well control equipment, or Well Control Equipment, on our four newly-built drillships. Such services include management of maintenance, certification and reliability with respect to such equipment. In connection with the contractual services agreement with GE, we agreed to sell the Well Control Equipment to another GE affiliate and subsequently lease back such equipment pursuant to separate ten-year operating leases.

During 2016, we completed four sale and leaseback transactions with respect to the Well Control Equipment on our ultra-deepwater drillships. As a result of these transactions, we received an aggregate of $210.0 million in proceeds from the sale of the Well Control Equipment on these rigs, which was less than the carrying value of the equipment. The resulting difference was recorded as prepaid rent with no gain or loss recognized on the transactions, and will be amortized over the respective terms of the operating leases. In connection with the sale of the equipment, we simultaneously executed four ten-year operating lease and contractual services agreements with respect to the Well Control Equipment. Future commitments under the operating leases and contractual services agreements for our ultra-deepwater drillships are estimated to be approximately $65.0 million per year or an aggregate $655.0 million over the term of the agreements. During the year ended December 31, 2016 we recognized $34.0 million in aggregate expense related to the Well Control Equipment leases and contractual services agreements.

14. Related-Party Transactions

Transactions with Loews. We are party to a services agreement with Loews, or the Services Agreement, pursuant to which Loews performs certain administrative and technical services on our behalf. Such services include personnel, internal auditing, accounting, and cash management services, in addition to advice and assistance with respect to preparation of tax returns and obtaining insurance. Under the Services Agreement, we are required to reimburse Loews for (i) allocated personnel costs (such as salaries, employee benefits and payroll taxes) of the Loews personnel actually providing such services and (ii) all out-of-pocket expenses related to the provision of such services. The Services Agreement may be terminated at our option upon 30 days' notice to Loews and at the option of Loews upon six months' notice to us. In addition, we have agreed to indemnify Loews for all claims and damages arising from the provision of services by Loews under the Services Agreement unless due to the gross negligence or willful misconduct of Loews. We were charged $1.0 million, $1.3 million and $1.1 million by Loews for these support functions during the years ended December 31, 2016, 2015 and 2014, respectively.

Transactions with Other Related Parties. We hire marine vessels and helicopter transportation services at the prevailing market rate from subsidiaries of SEACOR Holdings Inc. and Era Group Inc. The Chief Executive Officer and Executive Chairman of the Board of Directors of SEACOR Holdings Inc. and the Non-Executive Chairman of the Board of Directors of Era Group Inc. is also a member of our Board of Directors. We paid $0.7 million, $6.0 million and $0.8 million for the hire of such vessels and such services during the years ended December 31, 2016, 2015 and 2014, respectively.

The wife of our former President and Chief Executive Officer was an audit partner at Ernst & Young LLP, or E&Y, during his term of service with us. For the year ended December 31, 2014, we made payments aggregating $2.9 million to E&Y for tax and other consulting services; however, E&Y ceased to be a related party on March 3, 2014.

15. Restructuring and Separation Costs

During 2015, in response to the continuing decline in the offshore drilling market, we reviewed our cost and organization structure, and, as a result, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, also referred to as the Corporate Reduction Plan. As of December 31, 2015, appropriate communications had been made to substantially all impacted personnel, and we paid $9.8 million in restructuring and employee separation related costs during 2015. There were no accrued costs associated with the Corporate Reduction Plan as of December 31, 2015.

16. Income Taxes

Our income tax expense is a function of the mix between our domestic and international pre-tax earnings or losses, as well as the mix of international tax jurisdictions in which we operate. Certain of our rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or DFAC, a Cayman Islands subsidiary that we own. It is our intention to indefinitely reinvest future earnings of DFAC and its foreign subsidiaries to finance foreign activities. Accordingly, we have not made a provision for U.S. income taxes on approximately $1.8 billion of undistributed foreign earnings and profits. Although we do not intend to repatriate the earnings of our foreign subsidiary, and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practical to estimate this potential liability.

The components of income tax expense (benefit) are as follows:

	Year Ended December 31,		
	2016	2015	2014
		(In thousands)	
Federal — current	$ 230	$ 63,223	$ 66,843
State — current	(60)	93	(121)
Foreign — current	10,297	71,655	59,926
Total current	10,467	134,971	126,648
Federal — deferred	(108,274)	(245,045)	(6,699)
Foreign — deferred	2,011	3,011	8,231
Total deferred	(106,263)	(242,034)	1,532
Total	$ (95,796)	$(107,063)	$128,180

The difference between actual income tax expense and the tax provision computed by applying the statutory federal income tax rate to income before taxes is attributable to the following:

	Year Ended December 31,		
	2016	2015	2014
		(In thousands)	
Income before income tax expense:			
U.S.	$(146,037)	$ (11,158)	$288,080
Foreign	(322,262)	(370,190)	227,111
Worldwide	$(468,299)	$(381,348)	$515,191
Expected income tax expense at federal statutory rate	$(163,905)	$(133,472)	$180,317
Foreign earnings of foreign subsidiaries (not taxed at the statutory federal income tax rate) net of related foreign taxes	47,932	(5,518)	(46,163)
Foreign earnings of foreign subsidiaries for which U.S. federal income taxes have been provided	(1,265)	9	7,190
Foreign taxes of domestic and foreign subsidiaries for which U.S. federal income taxes have also been provided	28,569	27,193	38,358
Foreign tax credits	(26,663)	(26,590)	(39,843)
Allowance for foreign tax credits	62,400	—	—
Interest capitalized by foreign subsidiaries	(7,285)	(5,708)	(16,492)
Uncertain tax positions, including foreign currency revaluation	(42,423)	1,169	(47,964)
Amortization of deferred charges associated with intercompany rig sales to other tax jurisdictions	—	38,466	44,301
Net expense (benefit) in connection with resolutions of tax issues and adjustments relating to prior years	7,757	(2,283)	7,775
Other	(913)	(329)	701
Income tax (benefit) expense	$ (95,796)	$(107,063)	$128,180

Deferred Income Taxes. Significant components of our deferred income tax assets and liabilities are as follows:

	December 31, 2016	December 31, 2015
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards, or NOLs	$ 159,653	$ 143,231
Foreign tax credits	95,145	33,699
Worker's compensation and other current accruals	14,824	19,888
Bareboat charter deductions	23,353	32,469
UK depreciation deduction	21,222	17,358
Disputed receivables reserved	122	3,109
Deferred compensation	4,689	5,362
Foreign contribution taxes	3,857	3,630
Stock compensation awards	11,679	11,294
Deferred deductions	8,185	14,185
Interest — Uncertain Tax Positions	592	1,153
Other	1,812	2,089
Total deferred tax assets	345,133	287,467
Valuation allowance for NOLs	(91,219)	(93,191)
Valuation allowance for foreign tax credits	(62,400)	—
Valuation allowance for other deferred tax assets	(57,097)	(53,456)
Net deferred tax assets	134,417	140,820
Deferred tax liabilities:		
Depreciation	(284,480)	(372,334)
Mobilization	(46,274)	(30,990)
Unbilled revenue	(38)	(13,971)
Undistributed earnings of foreign subsidiaries	(220)	(50)
Other	(416)	(4)
Total deferred tax liabilities	(331,428)	(417,349)
Net deferred tax liability	$(197,011)	$(276,529)

We record a valuation allowance to derecognize a portion of our deferred tax assets, which we do not expect to be ultimately realized. A summary of changes in the valuation allowance is as follows:

	For the Year Ended December 31, 2016	2015	2014
		(In thousands)	
Valuation allowance as of January 1	$146,647	$ 48,036	$ 7,321
Establishment of valuation allowances:			
Net operating losses	10,318	82,155	15,677
Foreign tax credits	62,400	—	516
Other deferred tax assets	4,823	27,928	27,243
Releases of valuation allowances in various jurisdictions	(13,472)	(11,472)	(2,721)
Valuation allowance as of December 31	$210,716	$146,647	$48,036

Net Operating Loss Carryforwards — As of December 31, 2016, we had recorded a deferred tax asset of $159.7 million for the benefit of NOL carryforwards, $67.4 million related to our U.S. losses and $92.3 million related to our international operations. Approximately $33.7 million of this deferred tax asset relates to NOL carryforwards that have an indefinite life. The remaining $126.0 million relates to NOL carryforwards in various of our foreign subsidiaries as well as in the United States. Unless utilized, tax benefits of NOL carryforwards will expire between 2020 and 2036 as follows:

Year Expiring	Tax Benefit of NOL Carryforwards (In millions)
2020	$ 0.1
2021	0.1
2022	0.1
2023	0.1
2024	0.1
2025	58.1
2036	67.4
Total	$126.0

As of December 31, 2016, a valuation allowance for $91.2 million has been recorded for our NOLs for which the deferred tax assets are not likely to be realized.

Foreign Tax Credits. As of December 31, 2016, we had recorded a deferred tax asset of $95.1 million for the benefit of foreign tax credits in the U.S. We intend to carryback foreign tax credits of $32.7 million to prior years by filing amended tax returns. Unless utilized, our excess foreign tax credits of $62.4 million in the U.S. will expire in 2024, 2025 and 2026 as follows:

Year Expiring	Foreign Tax Credits (In millions)
2024	$ 6.6
2025	27.4
2026	28.4
Total	$62.4

As of December 31, 2016, a valuation allowance of $62.4 million has been recorded for our foreign tax credits for which the deferred tax assets are not likely to be realized.

Valuation Allowances — Other Deferred Tax Assets. As of December 31, 2016, we recorded valuation allowances for other deferred tax assets as follows:

Deferred Tax Asset	Valuation Allowance (In millions)
Bareboat charter deductions in the U.K.	$23.4
Depreciation deduction in the U.K.	21.7
Construction services invoices in Mexico	8.1
Foreign contribution taxes in Brazil	3.9
Total	$57.1

Unrecognized Tax Benefits. Our income tax returns are subject to review and examination in the various jurisdictions in which we operate and we are currently contesting various tax assessments. We accrue for income tax contingencies, or uncertain tax positions, that we believe are more likely than not exposures. A reconciliation of the beginning and ending amount of unrecognized tax benefits, gross of tax carryforwards and excluding interest and penalties, is as follows:

	For the Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Balance, beginning of period	$(53,952)	$(57,116)	$(90,921)
Additions for current year tax positions	(4,233)	(7,013)	(5,813)
Additions for prior year tax positions	(1,020)	(82)	(292)
Reductions for prior year tax positions	19,661	2,673	34,630
Reductions related to statute of limitation expirations	4,574	7,586	5,280
Balance, end of period	$(34,970)	$(53,952)	$(57,116)

The $19.7 million reduction for prior year tax positions results primarily from the devaluation of the Egyptian Pound.

At December 31, 2016, $2.1 million, $3.1 million and $35.0 million of the net liability for uncertain tax positions were reflected in “Other assets,” “Deferred tax liability” and “Other liabilities,” respectively. At December 31, 2015, $2.8 million, $1.9 million and $50.3 million of the net liability for uncertain tax positions were reflected in “Other assets,” “Deferred tax liability” and “Other liabilities,” respectively. Of the net unrecognized tax benefits at December 31, 2016, 2015 and 2014, all $36.0 million, $49.4 million and $50.5 million, respectively, would affect the effective tax rates if recognized.

The following table presents the amount of accrued interest and penalties at December 31, 2016 and 2015 related to uncertain tax positions:

	December 31,	
	2016	2015
	(In thousands)	
Uncertain tax positions net, excluding interest and penalties	$(36,019)	$(49,380)
Accrued interest on uncertain tax positions	(2,651)	(2,743)
Accrued penalties on uncertain tax positions	(16,751)	(39,924)
Uncertain tax positions net, including interest and penalties	$(55,421)	$(92,047)

We record interest related to accrued uncertain tax positions in interest expense and recognize penalties associated with uncertain tax positions in tax expense. Interest expense and penalties recognized during the three years ended December 31, 2016 related to uncertain tax positions are as follows:

	For the Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Net increase (decrease) in interest expense related to uncertain tax positions	$ (92)	$(4,761)	$ (5,283)
Net increase (decrease) in penalties related to uncertain tax positions	(23,172)	2,302	(22,175)

The $23.2 million reduction in penalties related to uncertain tax positions results primarily from the devaluation of the Egyptian Pound.

In several of the international locations in which we operate, certain of our wholly-owned subsidiaries enter into agreements with other of our wholly-owned subsidiaries to provide specialized services and equipment in support of our foreign operations. We apply a transfer pricing methodology to determine the amount to be charged for providing the services and equipment. In most cases, there are alternative transfer pricing methodologies that could be applied to these transactions and, if applied, could result in different chargeable amounts. Taxing authorities in the various foreign locations in which we operate could apply one of the alternative transfer pricing methodologies which could result in an increase to our income tax liabilities with respect to tax returns that remain subject to examination.

We expect the statute of limitations for the 2010 tax year to expire in 2017 for one of our subsidiaries operating in Malaysia, and we anticipate that the related unrecognized tax benefit will decrease by $3.0 million at that time.

Tax Returns and Examinations. We file income tax returns in the U.S. federal jurisdiction, various state jurisdictions and various foreign jurisdictions. Tax years that remain subject to examination by these jurisdictions include years 2009 to 2016. We are currently under audit in several of these jurisdictions. We do not anticipate that any adjustments resulting from the tax audit of any of these years will have a material impact on our consolidated results of operations, financial condition or cash flows.

U.S. Tax Jurisdiction. Our 2013 tax year is under audit by the U.S. Internal Revenue Service.

Brazil Tax Jurisdiction. In December 2009, we received an assessment of approximately $26.0 million for the years 2004 and 2005, including interest and penalty. We contested the tax assessment in 2010 and, during the third quarter of 2014, received a favorable court decision resulting in the closure of the 2004 and 2005 tax years. As a consequence, we reversed our $14.0 million reserve for this uncertain tax position, of which $3.5 million was interest and $4.4 million was penalty.

In February 2012, the tax authorities concluded their audit of our income tax return for the 2007 tax year for which we received an assessment of approximately $17.1 million for income tax, including interest and penalties. We contested the assessment and a court in Brazil ruled to cancel the assessment. However, the Brazilian tax authorities have appealed the ruling, and we are awaiting the outcome of the appeal. We have not accrued any tax expense related to this assessment. If our position is not sustained, tax expense and related interest and penalties as of December 31, 2016 would be approximately $13.7 million.

In addition, the Brazilian tax authorities have issued an assessment for the 2000 tax year of approximately $1.5 million as of December 31, 2016, including interest and penalty. We have appealed the tax assessment and are awaiting the outcome of the appeal.

Egypt Tax Jurisdiction. During 2014, we settled certain disputes for years 2006 through 2008 with the Egyptian tax authorities, which resulted in an aggregate $17.2 million reduction in tax expense, comprised of a $23.2 million reversal of uncertain tax positions, partially offset by $6.0 million in current foreign income tax expense. One issue for the 2006 through 2008 period remains open, which we appealed. Our court case is currently pending. We have sought assistance from an agency of the U.S. Treasury Department, pursuant to international tax treaties, and continue to believe that our position will, more likely than not, be sustained. However, if our position is not sustained, tax expense and related penalties would increase by approximately $22 million related to this issue for the 2006 through 2008 tax years as of December 31, 2016.

We are also under audit by the Egyptian tax authorities for the tax years 2009 through 2012.

Malaysia Tax Jurisdiction. During the year ended December 31, 2016, the statute of limitations for the 2009 tax year related to an uncertain tax position expired and we reversed our $5.6 million tax accrual, of which $2.1 million was penalty. During the third quarter of 2014, we received final approval from the Malaysian tax authorities for the settlement of tax liabilities and penalties for the years 2003 through 2008 resulting in the reversal of a $14.2 million reserve for uncertain tax positions for these years, of which $5.3 million was penalty.

Mexico Tax Jurisdiction. During the year ended December 31, 2016, the statute of limitations related to an uncertain tax position for the 2010 tax year expired, and we reversed our $1.6 million tax accrual, of which $0.7 million was interest and $0.3 million was penalty.

During the year ended December 31, 2015, the statute of limitations related to an uncertain tax position for the 2008 tax year expired, and we reversed our $3.8 million tax accrual, of which $1.3 million was interest and $0.5 million was penalty. In addition, the statute of limitations related to an uncertain tax position for the 2009 tax year expired, and we reversed our $10.7 million tax accrual, of which $3.6 million was interest and $1.4 million was penalty.

In August 2015, the Mexican tax authorities completed an audit for the 2008 tax year of one of our subsidiaries operating in Mexico and issued an assessment in the amount of $5.3 million, including interest and penalty. We have appealed the tax assessment and are awaiting the outcome of the appeal. We have not accrued any tax expense related to this assessment. In June 2015, the Mexican tax authorities initiated an audit of the 2009 income tax return of one of our other subsidiaries operating in Mexico. If our position is not sustained, tax expense and related interest and penalties as of December 31, 2016 would be approximately $4.6 million.

Due to the 2014 expiration of the statute of limitations in Mexico for the 2008 tax year for one of our subsidiaries operating in Mexico, we reversed our $8.0 million accrual for an uncertain tax position, of which $2.7 million was interest and $1.1 million was penalty, during the year ended December 31, 2014.

Australia Tax Jurisdiction. We are currently under audit for tax years 2010 through 2013.

17. Employee Benefit Plans

Defined Contribution Plans

We maintain defined contribution retirement plans for our U.S., U.K. and third-country national, or TCN, employees. The plan for our U.S. employees, or the 401k Plan, is designed to qualify under Section 401(k) of the Code. Under the 401k Plan, each participant may elect to defer taxation on a portion of his or her eligible earnings, as defined by the 401k Plan, by directing his or her employer to withhold a percentage of such earnings. A participating employee may also elect to make after-tax contributions to the 401k Plan. During 2016, 2015 and 2014, we matched 6% of each employee's compensation contributed to the 401k Plan. We made discretionary profit sharing contributions to the 401k Plan equal to 4% of a participant's defined compensation during 2014 and the first four months of 2015. We ceased making profit sharing contributions on May 1, 2015. Participants are fully vested in the employer match immediately upon enrollment in the 401k Plan and subject to a three-year cliff vesting period for any profit sharing contribution. For the years ended December 31, 2016, 2015 and 2014, our provision for contributions was $12.9 million, $23.8 million and $34.1 million, respectively.

The defined contribution retirement plan for our U.K. employees provides that we make annual contributions in an amount equal to the employee's contributions generally up to a maximum percentage of the employee's defined compensation per year. Our contribution for employees working in the U.K. sector of the North Sea during 2016 was 10% of the employee's defined compensation during the first six months of 2016 and was reduced to 6% for the remainder of 2016. Our contribution during 2015 and 2014 for employees working in the U.K. sector of the North Sea was 10% of the employee's defined compensation. Our provision for contributions was $2.0 million, $3.4 million and $5.0 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The defined contribution retirement plan for our TCN employees, or International Savings Plan, is similar to the 401k Plan. During 2016, 2015 and 2014, we matched 6% of each employee's compensation contributed to the International Savings Plan. During the four months ended April 30, 2015 and in 2014, we made discretionary profit sharing contributions to the International Savings Plan equal to 4% of a participant's defined compensation. We ceased making profit sharing contributions on May 1, 2015. Our provision for contributions was $0.8 million, $2.2 million and $3.7 million for 2016, 2015 and 2014, respectively.

Deferred Compensation and Supplemental Executive Retirement Plan

Our Amended and Restated Diamond Offshore Management Company Supplemental Executive Retirement Plan, or Supplemental Plan, provides benefits to a select group of our management or other highly compensated employees to compensate such employees for any portion of our base salary contribution and/or matching contribution under the 401k Plan that could not be contributed to that plan because of limitations within the Code. Our provision for contributions to the Supplemental Plan for 2016, 2015 and 2014 was approximately $146,000, $153,000 and $265,000, respectively.

18. Segments and Geographic Area Analysis

Although we provide contract drilling services with different types of offshore drilling rigs and also provide such services in many geographic locations, we have aggregated these operations into one reportable segment based on the similarity of economic characteristics due to the nature of the revenue-earning process as it relates to the offshore drilling industry over the operating lives of our drilling rigs.

Revenues from contract drilling services by equipment-type are listed below:

	Year Ended December 31,		
	2016	2015	2014
		(In thousands)	
Floaters:			
Ultra-Deepwater	$ 989,158	$1,339,059	$ 987,565
Deepwater	256,997	548,667	494,247
Mid-Water	248,846	387,549	1,076,842
Total Floaters	1,495,001	2,275,275	2,558,654
Jack-ups	30,213	84,909	178,472
Total contract drilling revenues	1,525,214	2,360,184	2,737,126
Revenues related to reimbursable expenses	75,128	59,209	77,545
Total revenues	$1,600,342	$2,419,393	$2,814,671

Geographic Areas

Our drilling rigs are highly mobile and may be moved to other markets throughout the world in response to market conditions or customer needs. At December 31, 2016, our actively-marketed drilling rigs were en route to or located offshore five countries in addition to the United States. Revenues by geographic area are presented by attributing revenues to the individual country or areas where the services were performed.

	Year Ended December 31, 2016	2015	2014
	(In thousands)		
United States	$ 548,024	$ 513,605	$ 418,095
International:			
South America	434,956	812,271	1,088,796
Europe/Africa/Mediterranean	344,964	532,824	558,367
Australia/Asia	234,182	415,033	503,814
Mexico	38,216	145,660	245,599
	1,052,318	1,905,788	2,396,576
Total revenues	$1,600,342	$2,419,393	$2,814,671

An individual international country may, from time to time, comprise a material percentage of our total contract drilling revenues from unaffiliated customers. For the years ended December 31, 2016, 2015 and 2014, individual countries that comprised 5% or more of our total contract drilling revenues from unaffiliated customers are listed below.

	Year Ended December 31, 2016	2015	2014
Brazil	18.0%	23.1%	31.0%
United Kingdom	15.3%	11.4%	10.7%
Australia	12.8%	7.0%	6.4%
Trinidad and Tobago	9.2%	9.8%	4.0%
Romania	4.0%	9.7%	3.9%
Mexico	2.4%	6.0%	8.7%
Malaysia	1.7%	6.8%	5.5%

The following table presents our long-lived tangible assets by geographic location as of December 31, 2016, 2015 and 2014. A substantial portion of our assets is comprised of rigs that are mobile, and therefore asset locations at the end of the period are not necessarily indicative of the geographic distribution of the earnings generated by such assets during the periods and may vary from period to period due to the relocation of rigs. In circumstances where our drilling rigs were in transit at the end of a calendar year, they have been presented in the tables below within the geographic area in which they were expected to operate.

	December 31,		
	2016(1)	2015(1)	2014
	(In thousands)		
Drilling and other property and equipment, net:			
United States	$2,753,511	$3,292,474	$2,637,621
International:			
Australia/Asia/Middle East	1,429,563	1,224,089	1,460,841
South America	1,030,069	1,051,283	1,445,832
Europe/Africa/Mediterranean	380,462	664,520	1,128,857
Mexico	133,330	146,448	272,802
	2,973,424	3,086,340	4,308,332
Total	$5,726,935	$6,378,814	$6,945,953

(1) During 2016 and 2015, we recorded an aggregate impairment loss of $678.1 million and $860.4 million, respectively, to write down certain of our drilling rigs and related equipment with indicators of impairment to their estimated recoverable amounts.

The following table presents the countries in which material concentrations of our long-lived tangible assets were located as of December 31, 2016, 2015 and 2014:

	December 31,		
	2016	2015	2014
United States	48.1%	51.6%	38.0%
Brazil	16.8%	15.3%	20.3%
Malaysia	13.6%	10.4%	6.6%
South Korea	—	4.2%	6.3%
Spain	—	2.7%	8.1%
Vietnam	—	—	6.9%

As of December 31, 2016, 2015 and 2014, no other countries had more than a 5% concentration of our long-lived tangible assets.

Major Customers

Our customer base includes major and independent oil and gas companies and government-owned oil companies. Revenues from our major customers for the years ended December 31, 2016, 2015 and 2014 that contributed more than 10% of our total revenues are as follows:

	Year Ended December 31,		
Customer	2016	2015	2014
Anadarko	22.4%	12.4%	3.6%
Petróleo Brasileiro S.A.	17.9%	24.1%	31.9%
ExxonMobil	5.8%	12.4%	5.0%

19. Unaudited Quarterly Financial Data

Unaudited summarized financial data by quarter for the years ended December 31, 2016 and 2015 is shown below.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2016				
Revenues	$ 470,543	$ 388,747	$349,178	$ 391,874
Operating (loss) income (1)	111,569	(626,669)	54,071	104,145
(Loss) income before income tax expense	83,196	(666,115)	34,746	79,874
Net (loss) income	87,425	(589,937)	13,927	116,082
Net (loss) income per share, basic and diluted	$ 0.64	$ (4.30)	$ 0.10	$ 0.85
2015				
Revenues	$ 620,056	$ 634,032	$609,742	$ 555,563
Operating (loss) income (2)	(269,530)	134,121	181,434	(340,099)
(Loss) income before income tax expense	(287,118)	106,028	159,767	(360,025)
Net (loss) income	(255,709)	90,386	136,422	(245,384)
Net (loss) income per share, basic and diluted	$ (1.86)	$ 0.66	$ 0.99	$ (1.79)

(1) During the second quarter of 2016, we recognized an aggregate impairment loss of $678.1 million to write down certain of our drilling rigs and related spare parts with indicators of impairment to their estimated recoverable amounts. See Notes 1 and 2.

(2) During the first, third and fourth quarters of 2015, we recognized impairment losses of $358.5 million, $2.6 million and $499.4 million, respectively, aggregating $860.4 million for the year ended December 31, 2015 to write down certain of our drilling rigs with indicators of impairment to their estimated recoverable amounts. See Notes 1 and 2.

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

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed by us under the federal securities laws is accumulated and communicated to our management to allow timely decisions regarding required disclosure.

Our Chief Executive Officer, or CEO, and Chief Financial Officer, or CFO, participated in an evaluation by our management of the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2016. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were not effective as of December 31, 2016, due to the material weakness in internal control over financial reporting described below.

Notwithstanding the existence of the material weakness described below, and based on a number of factors, including an internal review of the facts and circumstances of the material weakness, we believe that the Consolidated Financial Statements in Item 8 of this report fairly present, in all material respects, our financial position, results of operations and cash flows as of the dates, and for the periods, presented, in conformity with generally accepted accounting principles in the United States, or GAAP.

Internal Control Over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for Diamond Offshore Drilling, Inc. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed and operated, including the possibility of human error or mistakes, faulty judgments in decision-making and the possible circumvention or overriding of controls by individuals. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

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.

Our management, with the participation of our CEO and CFO, assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013)*. Based on this assessment, our management concluded that our internal control over financial reporting was not effective as of December 31, 2016, due to the material weakness described below.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement in our annual or interim financial statements will not be prevented or detected on a timely basis.

Material weakness in the review of the application of changes in foreign exchange rates to the calculation of our liability for uncertain tax positions denominated in foreign currency. We identified a material weakness in the design of our controls over the application of changes in foreign exchange rates when measuring our liability for uncertain tax positions denominated in foreign currencies. Our functional currency is the U.S. dollar for our worldwide operations. Our income tax returns are subject to review in the various tax jurisdictions in which we operate, and we often contest various tax assessments, which are considered to be income tax contingencies. We accrue for income tax contingencies or uncertain tax positions that we believe are more likely than not exposures. These liabilities for uncertain tax positions are considered monetary liabilities and are required to be revalued in accordance with Accounting Standards Codification 830 – *Foreign Currency Matters*. We have historically utilized a manual (non-system) calculation to revalue our foreign liability for uncertain tax positions, as appropriate.

After we had announced our preliminary earnings for the quarter and year ended December 31, 2016, and prior to the completion of our year-end financial reporting process for fiscal year 2016, it was discovered that our revaluation of our liability for uncertain tax positions did not properly reflect appropriate changes for current foreign exchange rates. This omission resulted in an improper measurement of certain of our liabilities for uncertain tax positions. The majority of the impact was related to the devaluation of the Egyptian Pound, primarily in the fourth quarter of 2016. As a result, we have concluded that we failed to adequately design and operate our internal controls over the application of changes in foreign exchange rates in revaluation of liabilities for foreign uncertain tax positions to mitigate the risk of material error.

Deloitte & Touche LLP, the registered public accounting firm that audited our financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting. The attestation report of Deloitte & Touche LLP is included following Item 9A of this Form 10-K.

Changes in Internal Control Over Financial Reporting

Except as described above, there have been no changes in our internal control over financial reporting that occurred during our fourth fiscal quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Remediation of Material Weakness in Internal Control Over Financial Reporting. With the oversight of senior management and the Audit Committee, subsequent to December 31, 2016, we have begun to develop plans to remediate the underlying cause of the material weakness identified above and improve the design and operating effectiveness of internal control over financial reporting and our disclosure controls. Our remediation plan will include the following actions:

- enhance our control process related to the creation of new accounts to ensure all foreign-denominated accounts are appropriately established in our accounting system for re-measurement, when required;
- require foreign-denominated accounts to be re-measured by our accounting system, thereby eliminating off-line manual calculations; and
- enhance our reconciliation procedures with respect to monetary assets and liabilities, including liabilities for uncertain tax positions, to require a comparison of the local currency balance to the U.S. dollar equivalent for reasonableness.

When fully implemented and operational, we believe the measures described above will remediate the material weakness we have identified and generally strengthen our internal control over financial reporting. As we continue to evaluate and work to improve our internal control over financial reporting, we may decide to take additional measures to address control deficiencies or determine to modify certain of the remediation measures described above. We will continue to monitor the effectiveness of these and other processes, procedures and controls and will make any further changes that management determines are appropriate.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Diamond
Offshore Drilling, Inc. and Subsidiaries Houston, Texas

We have audited Diamond Offshore Drilling, Inc. and subsidiaries' (the "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. The 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 Item 9A of this Form 10-K under the heading "Management's Annual Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment: Management identified a material weakness in the design of the controls over the review of the application of changes in foreign exchange rates when measuring their liability for uncertain tax positions denominated in foreign currencies. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2016, of the Company and this report does not affect our report on such financial statements.

In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of

December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 16, 2017 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 16, 2017

Item 9B. Other Information.

Not applicable.

PART III

Reference is made to the information responsive to Items 10, 11, 12, 13 and 14 of this Part III contained in our definitive proxy statement for our 2017 Annual Meeting of Stockholders, which is incorporated herein by reference.

Item 10. Directors, Executive Officers and Corporate Governance.

Item 11. Executive Compensation.

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

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

Item 14. Principal Accountant Fees and Services.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

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

See the Exhibit Index for a list of those exhibits filed herewith, which Exhibit Index also includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 of Regulation S-K.

Item 16. Form 10-K Summary.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 16, 2017.

DIAMOND OFFSHORE DRILLING, INC.

By: /s/ KELLY YOUNGBLOOD

Kelly Youngblood
Chief Financial Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Kelly Youngblood and David L. Roland and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and re-substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all documents relating to this Annual Report on Form 10-K, including any and all amendments and supplements thereto, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully as to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or their or his or her substitute or substitutes may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ MARC EDWARDS Marc Edwards	President, Chief Executive Officer and Director (Principal Executive Officer)	February 16, 2017
/s/ KELLY YOUNGBLOOD Kelly Youngblood	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 16, 2017
/s/ BETH G. GORDON Beth G. Gordon	Vice President and Controller (Principal Accounting Officer)	February 16, 2017
/s/ JAMES S. TISCH James S. Tisch	Chairman of the Board	February 16, 2017
/s/ JOHN R. BOLTON John R. Bolton	Director	February 16, 2017
/s/ CHARLES L. FABRIKANT Charles L. Fabrikant	Director	February 16, 2017
/s/ PAUL G. GAFFNEY II Paul G. Gaffney II	Director	February 16, 2017

Signature	Title	Date
/s/ EDWARD GREBOW Edward Grebow	Director	February 16, 2017
/s/ HERBERT C. HOFMANN Herbert C. Hofmann	Director	February 16, 2017
/s/ KENNETH I. SIEGEL Kenneth I. Siegel	Director	February 16, 2017
/s/ CLIFFORD M. SOBEL Clifford M. Sobel	Director	February 16, 2017
/s/ ANDREW H. TISCH Andrew H. Tisch	Director	February 16, 2017
/s/ RAYMOND S. TROUBH Raymond S. Troubh	Director	February 16, 2017

EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003) (SEC File No. 1-13926).
3.2	Amended and Restated By-laws (as amended through October 4, 2013) of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 8, 2013).
4.1	Indenture, dated as of February 4, 1997, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York) (as successor to The Chase Manhattan Bank), as Trustee (incorporated by reference to Exhibit 4.1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
4.2	Sixth Supplemental Indenture, dated as of May 4, 2009, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Mellon), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed May 4, 2009) (SEC File No. 1-13926).
4.3	Seventh Supplemental Indenture, dated as of October 8, 2009, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Mellon), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 8, 2009) (SEC File No. 1-13926).
4.4	Eighth Supplemental Indenture, dated as of November 5, 2013, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Mellon), as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed November 5, 2013).
10.1	Registration Rights Agreement (the “Registration Rights Agreement”) dated October 16, 1995 between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
10.2	Amendment to the Registration Rights Agreement, dated September 16, 1997, between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 1997) (SEC File No. 1-13926).
10.3	Services Agreement, dated October 16, 1995, between Loews Corporation and Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
10.4+	Amended and Restated Diamond Offshore Management Company Supplemental Executive Retirement Plan effective as of January 1, 2007 (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.5+	Diamond Offshore Management Bonus Program, as amended and restated, and dated as of December 31, 1997 (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the fiscal year ended December 31, 1997) (SEC File No. 1-13926).
10.6+	Diamond Offshore Drilling, Inc. Equity Incentive Compensation Plan (incorporated by reference to Exhibit B attached to our definitive proxy statement on Schedule 14A filed April 1, 2014).
10.7+	Form of Stock Option Certificate for grants to executive officers, other employees and consultants pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 1, 2004) (SEC File No. 1-13926).

Exhibit No.	Description
10.8+	Form of Stock Option Certificate for grants to non-employee directors pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed October 1, 2004) (SEC File No. 1-13926).
10.9+	The Diamond Offshore Drilling, Inc. Incentive Compensation Plan for Executive Officers (as Amended and Restated as of March 28, 2014) (incorporated by reference to Exhibit A attached to our definitive proxy statement on Schedule 14A filed April 1, 2014).
10.10+	Form of Award Certificate for stock appreciation right grants to the Company's executive officers, other employees and consultants pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed April 28, 2006) (SEC File No. 1-13926).
10.11+	Form of Award Certificate for stock appreciation right grants to non-employee directors pursuant to the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007) (SEC File No. 1-13926).
10.12+	Form of Award Certificate for grants of Performance Restricted Stock Units under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to our Quarterly Report Form 10-Q for the quarterly period ended March 31, 2014).
10.13+	Specimen Agreement for grants of restricted stock units to officers under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed March 30, 2015).
10.14+	Specimen Agreement for grants of restricted stock units to the Chief Executive Officer under the Equity Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to our Current Report on 8-K filed March 30, 2015).
10.15+	Employment Agreement between Diamond Offshore Management Company and Gary T. Krenek dated as of December 15, 2006 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed December 21, 2006) (SEC File No. 1-13926).
10.16+	Employment Agreement between Diamond Offshore Management Company and Lyndol L. Dew dated as of December 15, 2006 (incorporated by reference to Exhibit 10.17 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.17+	Employment Agreement between Diamond Offshore Management Company and Beth G. Gordon dated as of January 3, 2007 (incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006) (SEC File No. 1-13926).
10.18+	Amendment to Employment Agreement, dated April 1, 2015, between Diamond Offshore Management Company and Beth G. Gordon (incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015).
10.19+	Separation Agreement and General Release, dated March 30, 2015, between Diamond Offshore Management Company and John M. Vecchio (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015).
10.20	5-Year Revolving Credit Agreement, dated as of September 28, 2012, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 1, 2012).
10.21	Extension Agreement and Amendment No. 1 to Credit Agreement, dated as of December 9, 2013, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as an issuing bank, as swingline lender and as administrative agent for the lenders, and the lenders named therein (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2013).

Exhibit No.	Description
10.22	Commitment Increase and Amendment No. 2 to Credit Agreement, dated as of March 17, 2014, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as an issuing bank, as swingline lender and as administrative agent for the lenders, and the lenders named therein (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014).
10.23	Commitment Increase and Extension Agreement and Amendment No. 3 to Credit Agreement, dated as of October 22, 2014, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 24, 2014).
10.24	Extension Agreement and Amendment No. 4 to Credit Agreement, dated as of October 22, 2015, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015).
10.25	Agreement and Amendment No. 5 to Credit Agreement, dated as of August 18, 2016, among Diamond Offshore Drilling, Inc., Wells Fargo Bank, National Association, as administrative agent and swingline lender, the issuing banks named therein and the lenders named therein (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016).
10.26+	Employment Agreement, dated as of February 12, 2014, between Diamond Offshore Drilling, Inc., and Marc Edwards (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014).
10.27+	Separation Agreement, dated February 22, 2016, between Diamond Offshore Management Company and Gary T. Krenek (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016).
10.28+	Severance Agreement, dated May 2, 2016, between Diamond Offshore Drilling, Inc. and Kelly Youngblood (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016).
10.29+	Diamond Offshore Executive Retention Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 31, 2017).
10.30+	Form of Retention Agreement (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed January 31, 2017).
12.1*	Statement re Computation of Ratios.
21.1*	List of Subsidiaries of Diamond Offshore Drilling, Inc.
23.1*	Consent of Deloitte & Touche LLP.
24.1*	Power of Attorney (set forth on the signature page hereof).
31.1*	Rule 13a-14(a) Certification of the Chief Executive Officer.
31.2*	Rule 13a-14(a) Certification of the Chief Financial Officer.
32.1*	Section 1350 Certification of the Chief Executive Officer and Chief Financial Officer.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Calculation Linkbase Document.
101.LAB**	XBRL Taxonomy Label Linkbase Document.

Exhibit No.	Description
101.PRE**	XBRL Presentation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition.

* Filed or furnished herewith.

** The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, are deemed not filed for purposes of section 18 of the Exchange Act, and otherwise, not subject to liability under these sections.

\+ Management contracts or compensatory plans or arrangements.