DIAMOND OFFSHORE DRILLING INC
Form 10-Q
October 31, 2016
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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 of principal executive offices)

(Zip Code)

(281) 492-5300

(Registrant s telephone number, including area code)

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 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

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

As of October 26, 2016 Common stock, $0.01 par value per share 137,169,663 shares

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QUARTER ENDED SEPTEMBER 30, 2016

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements.

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share and per share data)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 81,329	$ 119,028
Marketable securities	46	11,518
Accounts receivable, net of allowance for bad debts	273,982	405,370
Prepaid expenses and other current assets	114,166	119,479
Assets held for sale	7,600	14,200
Total current assets	477,123	669,595
Drilling and other property and equipment, net of accumulated depreciation	5,819,309	6,378,814
Other assets	112,743	101,485
Total assets	$ 6,409,175	$ 7,149,894
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 36,480	$ 70,272
Accrued liabilities	224,390	253,769
Taxes payable	36,911	15,093
Short-term borrowings	182,100	286,589
Total current liabilities	479,881	625,723
Long-term debt	1,980,602	1,979,778
Deferred tax liability	164,389	276,529
Other liabilities	151,375	155,094
Total liabilities	2,776,247	3,037,124

Commitments and contingencies (Note 10)		
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 September 30, 2016; 143,978,877 shares issued and 137,158,706 shares outstanding at December 31, 2015)	1,440	1,440
Additional paid-in capital	2,003,388	1,999,634
Retained earnings	1,830,683	2,319,136
Accumulated other comprehensive gain (loss)	3	(5,035)
Treasury stock, at cost (6,828,094 and 6,820,171 shares of common stock at September 30, 2016 and December 31, 2015, respectively)	(202,586)	(202,405)
Total stockholders equity	3,632,928	4,112,770
Total liabilities and stockholders equity	$ 6,409,175	$ 7,149,894

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share data)

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Revenues:				
Contract drilling	$ 339,636	$ 599,036	$ 1,140,568	$ 1,816,055
Revenues related to reimbursable expenses	9,542	10,706	67,900	47,775
Total revenues	349,178	609,742	1,208,468	1,863,830
Operating expenses:				
Contract drilling, excluding depreciation	186,654	277,944	597,831	971,471
Reimbursable expenses	7,965	10,476	51,283	46,904
Depreciation	86,473	118,086	295,729	378,714
General and administrative	15,237	16,888	48,774	50,888
Impairment of assets		2,546	678,145	361,074
Restructuring and separation costs		1,574		8,735
(Gain) loss on disposition of assets	(1,222)	794	(2,265)	19
Total operating expenses	295,107	428,308	1,669,497	1,817,805
Operating income (loss)	54,071	181,434	(461,029)	46,025
Other income (expense):				
Interest income	150	629	592	1,796
Interest expense, net of amounts capitalized	(19,032)	(21,350)	(68,704)	(70,800)
Foreign currency transaction (loss) gain	(712)	(1,163)	(7,833)	954
Other, net	269	217	(11,199)	702
Income (loss) before income tax (expense) benefit	34,746	159,767	(548,173)	(21,323)
Income tax (expense) benefit	(20,819)	(23,345)	59,588	(7,578)
Net income (loss)	$ 13,927	$ 136,422	$ (488,585)	$ (28,901)
Earnings (loss) per share, Basic and Diluted	$ 0.10	$ 0.99	$ (3.56)	$ (0.21)

Weighted-average shares outstanding:				
Shares of common stock	137,170	137,159	137,167	137,156
Dilutive potential shares of common stock	84	44		
Total weighted-average shares outstanding	137,254	137,203	137,167	137,156
Cash dividends declared per share of common stock	$	$ 0.125	$	$ 0.375

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Net income (loss)	$ 13,927	$ 136,422	$ (488,585)	$ (28,901)
Other comprehensive (losses) gains, net of tax:				
Derivative financial instruments:				
Unrealized holding loss		(40)		(1,574)
Reclassification adjustment for loss (gain) included in net income (loss)		268	(3)	5,085
Investments in marketable securities:				
Unrealized holding loss	(1)	(2,440)	(6,559)	(2,733)
Reclassification adjustment for loss included in net income (loss)			11,600	
Total other comprehensive (loss) gain	(1)	(2,212)	5,038	778
Comprehensive income (loss)	$ 13,926	$ 134,210	$ (483,547)	$ (28,123)

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating activities:		
Net loss	$ (488,585)	$ (28,901)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation	295,729	378,714
Loss on impairment of assets	678,145	361,074
(Gain) loss on disposition of assets	(2,265)	19
Loss on sale of marketable securities, net	12,146	
Loss on foreign currency forward exchange contracts		8,364
Deferred tax provision	(114,405)	(114,662)
Stock-based compensation expense	3,754	3,503
Deferred income, net	(23,381)	(24,735)
Deferred expenses, net	(1,099)	(42,261)
Other assets, noncurrent	(677)	774
Other liabilities, noncurrent	3,021	(3,844)
Payments for settlement of foreign currency forward exchange contracts designated as accounting hedges		(8,364)
Other	1,997	998
Changes in operating assets and liabilities:		
Accounts receivable	131,388	(33,360)
Prepaid expenses and other current assets	3,950	10,979
Accounts payable and accrued liabilities	(32,762)	(112,206)
Taxes payable	25,038	70,585
Net cash provided by operating activities	491,994	466,677
Investing activities:		
Capital expenditures (including rig construction)	(598,236)	(758,342)
Proceeds from disposition of assets, net of disposal costs	169,038	8,442
Proceeds from sale and maturities of marketable securities	4,603	34
Net cash used in investing activities	(424,595)	(749,866)
Financing activities:		
Net (repayment of) proceeds from short-term borrowings	(104,489)	492,996

Repayment of long-term debt		(250,000)
Payment of dividends and anti-dilution payments	(408)	(52,287)
Other	(201)	(12)
Net cash (used in) provided by financing activities	(105,098)	190,697
Net change in cash and cash equivalents	(37,699)	(92,492)
Cash and cash equivalents, beginning of period	119,028	233,623
Cash and cash equivalents, end of period	$ 81,329	$ 141,131

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

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

The unaudited consolidated financial statements of Diamond Offshore Drilling, Inc. and subsidiaries, which we refer to as Diamond Offshore, we, us or our, should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2015 (File No. 1-13926).

As of October 26, 2016, Loews Corporation owned approximately 53% of the outstanding shares of our common stock.

Interim Financial Information

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the U.S., or GAAP, for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission. Accordingly, pursuant to such rules and regulations, they do not include all disclosures required by GAAP for complete financial statements. The consolidated financial information has not been audited but, in the opinion of management, includes all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of Diamond Offshore s consolidated balance sheets, statements of operations, statements of comprehensive income and statements of cash flows at the dates and for the periods indicated. Results of operations for interim periods are not necessarily indicative of results of operations for the respective full years.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with 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.

Assets Held For Sale

At December 31, 2015, we reported the $14.2 million carrying value of five marketed-for-sale jack-up rigs as Assets held for sale in our Consolidated Balance Sheets. One of these rigs was sold for $8.0 million in February 2016. At September 30, 2016, we reported Assets held for sale of $7.6 million in our Consolidated Balance Sheets, consisting of $6.2 million for our four marketed-for-sale jack-up rigs and $1.4 million for two of our semisubmersible rigs, which we expect to sell as scrap in the fourth quarter of 2016.

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. During the nine-month period ended September 30, 2016 and the year ended December 31, 2015, we capitalized $154.8 million and $262.4 million, respectively, in replacements and betterments of our drilling fleet. See

Notes 2 and 8.

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Capitalized Interest

We capitalize interest cost for qualifying construction and upgrade projects. See Note 8. A reconciliation of our total interest cost to Interest expense, net of amounts capitalized as reported in our Consolidated Statements of Operations is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Total interest cost, including amortization of debt issuance costs	$ 27,016	$ 23,830	$ 83,888	$ 84,254
Capitalized interest	(7,984)	(2,480)	(15,184)	(13,454)
Total interest expense as reported	$ 19,032	$ 21,350	$ 68,704	$ 70,800

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 the rig s 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, 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.

Debt Issuance Costs

Historically, we have presented deferred costs associated with the issuance of long-term debt as Other Assets in our unaudited 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

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. Earlier adoption is permitted. We are currently evaluating the provisions of ASU 2016-09 and have not yet determined the 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 have not yet determined the impact of ASU 2016-02 on our financial position, results of operations or cash flows.

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.

The guidance of ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and may be adopted using a retrospective or modified retrospective approach. We have not yet determined the impact of ASU 2014-09 on our financial position, results of operations or cash flows.

2. Asset Impairments

2016 Impairments - During the second quarter of 2016, in response to the continuing decline in industry-wide utilization for semisubmersible rigs, further exacerbated by additional and more frequent contract cancelations by customers, declining dayrates, as well as the output 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 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.

In the second quarter of 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, consisting of three ultra-deepwater, three deepwater and two mid-water semisubmersible rigs, were impaired (we collectively refer to these eight rigs as the Second Quarter 2016 Impaired Rigs).

We estimated the fair value of the Second Quarter 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 Second Quarter 2016 Impaired Rigs

In the third quarter of 2016, we evaluated nine 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 these rigs were not impaired. If market fundamentals in the offshore oil and gas industry deteriorate further, we may be required to recognize additional impairment losses in future periods.

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.

Of the 2015 Impaired Rigs, six mid-water semisubmersible rigs, our older drillship and one marketed-for-sale jack-up rig have been sold. At September 30, 2016, eight rigs impaired during 2015 or 2016 were cold stacked and an additional four jack-up rigs were being marketed for sale. Two previously-impaired semisubmersible rigs have been retired and are expected to be sold as scrap in the near term.

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3. Supplemental Financial Information

Consolidated Balance Sheets Information

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

	September 30, 2016	December 31, 2015
	(In thousands)	
Trade receivables	$ 255,935	$ 390,429
Value added tax receivables	21,812	14,475
Amounts held in escrow	995	4,966
Related party receivables	142	167
Other	822	1,057
	279,706	411,094
Allowance for bad debts	(5,724)	(5,724)
Total	$ 273,982	$ 405,370

Prepaid expenses and other current assets consist of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Rig spare parts and supplies	$ 26,690	$ 42,804
Deferred mobilization costs	54,734	52,965
Prepaid insurance	4,697	4,483
Prepaid taxes	19,794	14,969
Prepaid BOP Lease	2,987	
Other	5,264	4,258
Total	$ 114,166	$ 119,479

During the nine-month period ended September 30, 2016, we recognized an $8.1 million impairment loss related to our rig spare parts and supplies.

Accrued liabilities consist of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Rig operating expenses	$ 40,157	$ 47,426

Payroll and benefits	44,331	59,787
Deferred revenue	14,922	31,542
Accrued capital project/upgrade costs	65,286	84,146
Interest payable	44,130	18,365
Personal injury and other claims	6,243	8,320
Other	9,321	4,183
Total	$ 224,390	$ 253,769

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Consolidated Statements of Cash Flows Information

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

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 65,286	$ 42,325
Common stock withheld for payroll tax obligations [1]	181	236
Cash interest payments[2]	53,433	57,625
Cash income taxes paid, net of (refunds):		
U.S. federal		(3,344)
Foreign	33,479	53,292
State	1	150

[1] Represents the cost of 7,923 shares and 7,810 shares of common stock withheld to satisfy payroll tax obligations incurred as a result of the vesting of restricted stock units in the nine months ended September 30, 2016 and 2015, respectively. These costs are presented as a deduction from stockholders equity in Treasury stock in our Consolidated Balance Sheets at September 30, 2016 and 2015.

[2] Interest payments, net of amounts capitalized, were $43.6 million and $48.7 million for the nine-month periods ended September 30, 2016 and 2015, respectively.

4. Earnings Per Share

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

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(In thousands, except per share data)			
Net income (loss) basic and diluted numerator	$ 13,927	$ 136,422	$ (488,585)	$ (28,901)
Weighted average shares basic (denominator):	137,170	137,159	137,167	137,156
Dilutive effect of stock-based awards	84	44		
Weighted average shares including conversions diluted (denominator)	137,254	137,203	137,167	137,156
Earnings (loss) earnings per share:				
Basic	$ 0.10	$ 0.99	$ (3.56)	$ (0.21)

Diluted	$ 0.10	$ 0.99	$ (3.56)	$ (0.21)

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 anti-dilutive for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Employee and director:				
Stock options	6	23	8	29
Stock appreciation rights	1,469	1,521	1,519	1,561
Restricted stock units	423	176	687	252

5. Marketable Securities

We report our investments as current assets in our Consolidated Balance Sheets in Marketable securities, representing the investment of cash available for current operations. See Note 7.

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

	September 30, 2016		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
Mortgage-backed securities	$ 45	$ 1	$ 46

	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

In June 2016, we sold our investment in corporate bonds for proceeds of $4.6 million and recognized a loss of $12.9 million, including $0.8 million in accrued interest that we do not expect to collect.

Proceeds from maturities and sales of mortgage-backed securities and the related gains and losses during the three-month and nine-month periods ended September 30, 2016 and 2015 were not significant.

6. Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

During the nine months ended September 30, 2015, we settled foreign currency forward exchange, or FOREX, contracts with aggregate notional values of approximately $91.6 million, of which the entire aggregate amount was designated as a cash flow accounting hedge. We did not settle any FOREX contracts during the nine months ended September 30, 2016 and had no FOREX contracts outstanding at September 30, 2016 or December 31, 2015.

During the three-month and nine-month periods ended September 30, 2015, we recognized aggregate losses of $0.5 million and $8.4 million, respectively, related to our FOREX contracts designated as accounting hedges. We have presented these amounts within Contract drilling, excluding depreciation 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 three-month and nine-month periods ended September 30, 2015. In the table, AOCGL refers to accumulated other comprehensive gain (loss).

	Period Ended September 30, 2015 Three Months	Nine Months
	(In thousands)	
FOREX contracts:		
Amount of loss recognized in AOCGL on derivative (effective portion)	$ (61)	$ (2,420)
Location of loss reclassified from AOCGL into income (effective portion)	Contract drilling expense	Contract drilling expense
Amount of loss reclassified from AOCGL into income (effective portion)	$ (415)	$ (7,829)
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction (loss) gain	Foreign currency transaction (loss) gain
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$	$ (1)

During the nine-month period ended September 30, 2015, we did not reclassify any amounts from AOCGL due to the probability of an underlying forecasted transaction not occurring.

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7. Financial Instruments and Fair Value Disclosures

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 residential 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 has consisted 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 September 30, 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.

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 September 30, 2016 consisted of cash held in money market funds of $55.4 million and time deposits of $20.4 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 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 inputs used in our valuation are obtained from a Bloomberg curve analysis which uses par coupon swap rates to calculate implied forward rates so that projected floating rate cash flows can be calculated. 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 September 30, 2016 consisted of nonrecurring measurements of certain of our drilling rigs and associated spare parts and supplies for which we recorded impairment losses during the second quarter of 2016 and the year ended December 31, 2015. See Notes 1, 2 and 3.

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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 three-month and nine-month periods ended September 30, 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 rig spare parts and supplies, which were measured at fair value on a nonrecurring basis during the three-month periods ended March 31, 2015, September 30, 2015, December 31, 2015 and June 30, 2016 of $358.5 million, $2.6 million, $499.4 million and $678.1 million, respectively.

Assets and liabilities measured at fair value are summarized below:

	September 30, 2016				
	Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Nine Months Ended [1]
			(In thousands)		
Recurring fair value measurements:					
Assets:					
Short-term investments	$ 75,850	$	$	$ 75,850	
Mortgage-backed securities		46		46	
Total assets	$ 75,850	$ 46	$	$ 75,896	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets [2][3]	$	$	$ 85,091	$ 85,091	$ 678,145

(1) Represents impairment losses of $8.1 million and $670.0 million recognized during the nine-month period ended September 30, 2016 related to our rig spare parts and supplies and the Second Quarter 2016 Impaired Rigs, respectively. See Notes 2 and 3.

(2) Represents the total book value as of September 30, 2016 for 16 drilling rigs ($60.9 million), which were written down to their estimated recoverable amounts in 2015 and 2016, and for rig spare parts and supplies ($24.2 million), which were written down to their estimated recoverable amounts in the second quarter of 2016. Of the total fair value, $24.2 million, $7.6 million and $53.3 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 September 30, 2016. See Notes 1, 2 and 3.

(3)

Includes depreciation expense of $15.8 million recognized in nine-month period ended September 30, 2016 for rigs which have previously been written down to their estimated fair values using an income approach and are still under contract. Also excludes the fair value of one marketed-for-sale jack-up rig and two mid-water semisubmersible rigs sold during the first nine months of 2016.

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	December 31, 2015 Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Year Ended (1)
		(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 rigs impaired during 2015.

(2) Represents the book value of our rigs impaired during 2015, 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 prior to December 31, 2015.

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 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 September 30, 2016 and December 31, 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 period of the report date. Fair values and related carrying values of our senior notes are shown below.

	September 30, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.875% Senior Notes due 2019	$ 518.8	$ 499.8	$ 506.8	$ 499.7
3.45% Senior Notes due 2023	218.5	249.2	208.0	249.2
5.70% Senior Notes due 2039	393.2	497.1	360.0	497.0
4.875% Senior Notes due 2043	520.5	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.

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8. Drilling and Other Property and Equipment

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

	September 30, 2016	December 31, 2015
	(In thousands)	
Drilling rigs and equipment	$ 8,217,405	$ 9,345,484
Construction work-in-progress	748,426	269,605
Land and buildings	64,415	64,775
Office equipment and other	72,312	71,537
Cost	9,102,558	9,751,401
Less: accumulated depreciation	(3,283,249)	(3,372,587)
Drilling and other property and equipment, net	$ 5,819,309	$ 6,378,814

During the nine-month period ended September 30, 2016, we recognized an aggregate impairment loss of $670.0 million related to the Second Quarter 2016 Impaired Rigs. See Notes 1 and 2.

See Note 13 for a discussion of three sale and leaseback transactions that were executed during the nine-month period ended September 30, 2016.

Construction work-in-progress, including capitalized interest, at September 30, 2016 and December 31, 2015 was $748.4 million and $269.6 million, respectively, attributable to the *Ocean GreatWhite*, a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig, which was delivered by Hyundai Heavy Industries Co., Ltd., or HHI, in July 2016.

9. Credit Agreement, Commercial Paper and Credit Ratings

In February 2016, Moody s Investors Service, or Moody s, downgraded our senior unsecured credit rating to Ba2 from Baa2, with a stable outlook, and also downgraded our short-term credit rating to sub-prime. In July 2016, S&P Global Ratings (formerly Standard & Poor s Ratings Services) downgraded our senior unsecured credit rating to BBB from BBB+ with a negative outlook.

As a result of the Moody s downgrade 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. We no longer obtain a short-term credit rating from either rating agency. Based on our current credit ratings, the applicable interest rate for alternate base rate loans under our revolving 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 our revolving credit agreement is currently 1.25% over British Bankers Association LIBOR. The applicable commitment fee is 0.20%, and the participation fee for performance letters of credit is 0.625%.

In January 2016, we repaid the $286.6 million in commercial paper notes outstanding at December 31, 2015 with proceeds from borrowings under our revolving credit agreement. At September 30, 2016, we had $182.1 million in borrowings outstanding under our revolving credit agreement. These borrowings bore interest at a weighted average interest rate of 1.8%.

As of October 27, 2016, we had $221.5 million in borrowings outstanding and an additional $1.28 billion available under our revolving credit agreement.

10. 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 one of our customers in Brazil, Petróleo Brasileiro S.A., or 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 since 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 have filed appropriate motions to dismiss these claims. 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. 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 September 30, 2016 our estimated liability for personal injury claims was $33.3 million, of which $6.1 million and $27.2 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

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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. In June 2016, we funded the final payment to HHI totaling $402.5 million in final settlement of the contract price for the *Ocean GreatWhite*.

At September 30, 2016, we had no other purchase obligations for major rig upgrades or any other significant obligations, except for those related to our direct rig operations, that arise during the normal course of business. See Note 13.

Letters of Credit and Other. We were contingently liable as of September 30, 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 $54.1 million of performance, tax, supersedeas, court and customs bonds can require collateral at any time. As of September 30, 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.

11. Accumulated Other Comprehensive Gain (Loss)

The components of our AOCGL and related changes thereto are as follows:

	Unrealized (Loss) Gain on Derivative Financial Instruments	Unrealized (Loss) Gain on Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2016	$ 6	$ (5,041)	$ (5,035)
		(6,559)	(6,559)

Change in other comprehensive loss before reclassifications, after tax of $0 and $1			
Reclassification adjustments for items included in Net Loss, after tax of $3 and $0	(3)	11,600	11,597
Balance at September 30, 2016	$ 3	$	$ 3

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

Major Category of AOCGL	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Consolidated Statements of Operations Line Items
	(In thousands)				
Derivative Financial Instruments:					
Unrealized loss on FOREX contracts	$	$ 415	$	$ 7,829	Contract drilling, excluding depreciation
Unrealized (gain) on treasury lock agreements	(2)	(2)	(6)	(6)	Interest expense
	2	(145)	3	(2,738)	Income tax expense
Total, net of tax	$	$ 268	$ (3)	$ 5,085	
Marketable Securities:					
Unrealized loss on marketable securities	$	$	$ 11,600	$	Other, net
					Income tax expense
Total, net of tax	$	$	$ 11,600	$	

12. Restructuring and Separation Costs

In early 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. We recognized $1.6 million and $8.7 million in restructuring and employee separation-related costs for the three-month and nine-month periods ended September 30, 2015, respectively. Substantially all costs associated with the Corporate Reduction Plan had been paid as of September 30, 2015.

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 the nine months ended September 30, 2016, we completed three sale and leaseback transactions with respect to the Well Control Equipment on the *Ocean BlackHawk, Ocean BlackHornet* and *Ocean BlackLion*. As a result of these transactions, we received an aggregate of $157.5 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 three 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 the *Ocean BlackHawk, Ocean BlackHornet* and *Ocean BlackLion* are estimated to be approximately $49.0 million per year or an aggregate $491.0 million over the term of the agreements. We expect to complete the remaining sale and leaseback transaction for the *Ocean BlackRhino* in the fourth quarter of 2016.

14. 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 international rigs are owned and operated, directly or indirectly, by one of our wholly owned foreign subsidiaries. It is our intention to indefinitely reinvest future earnings of this subsidiary to finance foreign activities. Accordingly, we have not made a provision for U.S. income taxes on such earnings except to the extent that such earnings were immediately subject to U.S. income taxes.

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At December 31, 2015 we had recorded a deferred tax asset of $33.7 million for the benefit of foreign tax credits in the U.S. that we expected to utilize prior to their expiration in 2024 and 2025. As of September 30, 2016, we no longer expect to be able to realize this future tax benefit and, accordingly, we established a valuation allowance of $33.7 million in the second quarter of 2016 for the prior year deferred tax asset. We have also recorded a $27.1 million valuation allowance for the deferred tax asset for the benefit of foreign tax credits arising in 2016 that we do not expect to be able to utilize prior to their expiration in 2026.

15. 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Floaters:				
Ultra-Deepwater	$ 217,275	$ 376,195	$ 757,338	$ 943,261
Deepwater	66,011	136,668	192,319	456,542
Mid-Water	56,350	69,500	160,716	342,783
Total Floaters	339,636	582,363	1,110,373	1,742,586
Jack-ups		16,673	30,195	73,469
Total contract drilling revenues	339,636	599,036	1,140,568	1,816,055
Revenues related to reimbursable expenses	9,542	10,706	67,900	47,775
Total revenues	$ 349,178	$ 609,742	$ 1,208,468	$ 1,863,830

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 September 30, 2016, our actively-marketed drilling rigs were en route to or located offshore in four 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			

United States	$ 121,895	$ 140,898	$ 414,087	$ 330,765
International:				
South America	105,614	222,717	333,803	654,432
Europe	63,117	132,345	253,287	420,147
Australia/Asia	56,688	86,608	169,323	333,628
Mexico	1,864	27,174	37,968	124,858
Total revenues	$ 349,178	$ 609,742	$ 1,208,468	$ 1,863,830

16. Subsequent Event

On October 26, 2016, we executed a settlement agreement with a former customer in connection with a contractual dispute regarding one of our rigs that had previously worked in the North Sea. Pursuant to the agreement, we expect to receive compensation of approximately $36.0 million in the fourth quarter of 2016 in full settlement of the dispute.

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ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion should be read in conjunction with our unaudited consolidated financial statements (including the notes thereto) included elsewhere in this report and our audited consolidated financial statements and the notes thereto, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 1A, Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2015. References to Diamond Offshore, we, us or our mean Diamond Offshore Drilling, Inc., a Delaware corporation, and its subsidiaries.

We provide contract drilling services worldwide with a fleet of 24 offshore drilling rigs. Our current fleet consists of four drillships, 19 semisubmersibles and one jack-up rig. We have four additional jack-up rigs being marketed for sale. In October 2016, we sold one of two retired semisubmersible rigs for scrap and expect to complete the sale of the remaining retired rig by the end of 2016. The *Ocean GreatWhite*, is expected to be available for customer acceptance shortly. See Contract Drilling Backlog.

Market Overview

Oil prices, which had fallen to a 12-year low of less than $30 per barrel in January 2016, rebounded into the low-$50 per barrel range by the end of the third quarter of 2016, but continue to exhibit day-to-day volatility due to multiple factors, including fluctuations in the current and expected level of global oil inventories. As a result, overall fundamentals in the offshore oil and gas industry have not improved, and, in some markets, have deteriorated further. Despite the increase in oil prices during the third quarter of 2016, industry reports indicate that utilization for floaters continues to fall and cancelation of contracts for deepwater rigs has persisted. Prospective customers for contract drilling services are currently formulating their 2017 capital spending programs, and it is unlikely that capital spending for exploration and development will exceed 2016 levels, assuming commodity prices remain at current levels. Customer inquiries for rig availability and new tenders have continued to decline in 2016, as compared to prior years, although recently there has been a slight increase in rig tendering activity, primarily for projects commencing in 2018 and later.

The oversupply of drilling rigs in the floater markets continues to persist. Industry analysts report that 65 floater rigs have been cold stacked since the beginning of 2016 and an additional 17 floaters have been scrapped year-to-date, with an additional three units estimated to be scrapped by year end. Despite these events, the number of available rigs continues to grow as contracted rigs come off contract and newly-built rigs are delivered. As of the date of this report, industry data indicates that there are approximately 36 competitive, or non-owner-operated, newbuild floaters on order, of which only three rigs are reported to be contracted for future work. Of the 36 rigs on order, nine and 16 rigs are scheduled for delivery in the remainder of 2016 and in 2017, respectively. The remaining 11 rigs are scheduled for delivery between 2018 and 2020. Industry analysts predict that delivery dates may shift further as newbuild owners negotiate with their respective shipyards.

Competition for the limited number of drilling jobs continues to be intense. In some cases, dayrates have been negotiated at break-even levels, or below, to provide for the recovery of a portion of operating costs for rigs that would otherwise be uncontracted or cold stacked. In addition, customer discussions indicate a preference for hot rigs rather than the reactivation of cold-stacked rigs. This preference incentivizes the drilling contractor to contract rigs at lower rates to maintain the rigs in an active state and allow for at least partial cost recovery. Industry analysts have predicted that the offshore contract drilling market may remain depressed with further declines in dayrates and utilization likely into 2017.

As a result of the continuing and worsening market conditions for 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 could include requests to lower the contract dayrate, lowering of a dayrate in exchange for additional contract term, shortening 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. 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, certain 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.

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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.

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 expect to scrap a rig, we evaluate the rig for impairment. We currently expect that these adverse market conditions will continue for the foreseeable future. As of October 1, 2016, ten rigs in our fleet were cold stacked and an additional four jack-up rigs are currently being marketed for sale. We have two retired semisubmersible rigs, which we expect to sell for scrap value in the fourth quarter of 2016. See Contract Drilling Backlog for future commitments of our rigs during 2016 through 2020.

Our results of operations and cash flows for the quarter ended September 30, 2016 have been negatively impacted by the continuing and worsening market conditions in the offshore drilling industry, as discussed above. See Results of Operations and Liquidity and Capital Resources and Notes 1 and 2 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of October 1, 2016, February 16, 2016 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2015), and October 1, 2015 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 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.

In October 2016, BP notified us that they would no longer pursue a drilling campaign in the Great Australian Bight where the *Ocean GreatWhite* was to be the primary drilling rig for the campaign. BP has confirmed that its decision will not impact the contract for the rig. BP is exploring alternative locations for the *Ocean GreatWhite*.

In August 2016, our subsidiary received notice of termination of its drilling contract from Petróleo Brasileiro S.A., or Petrobras, the customer for the *Ocean Valor*. In August 2016, 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. The drilling contract provides for a dayrate of approximately $455,000 and was estimated to conclude in accordance with its terms in October 2018. The rig is currently on standby earning a reduced dayrate. 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; however, litigation is inherently unpredictable, and there can be no assurance as to the ultimate outcome of this matter.

	October 1, 2016	February 16, 2016	October 1, 2015
		(In thousands)	
Contract Drilling Backlog			
Ultra-Deepwater Floaters [(1)]	$ 3,614,000	$ 4,415,000	$ 4,851,000
Deepwater Floaters	258,000	375,000	439,000
Other Rigs [(2)]	210,000	405,000	419,000
Total	$ 4,082,000	$ 5,195,000	$ 5,709,000

(1) Contract drilling backlog as of October 1, 2016 for our ultra-deepwater floaters includes (i) $641.0 million for the years 2017 to 2020 attributable to future work for the semisubmersible *Ocean GreatWhite*, which is

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contracted to BP, and (ii) $306.3 million from 2016 to 2018 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.

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

The following table reflects the amount of our contract drilling backlog by year as of October 1, 2016.

		For the Years Ending December 31,			
	Total	2016 (1)	2017	2018	2019 - 2020
			(In thousands)		
Contract Drilling Backlog					
Ultra-Deepwater Floaters (2)	$ 3,614,000	$ 243,000	$ 1,187,000	$ 1,129,000	$ 1,055,000
Deepwater Floaters	258,000	68,000	181,000	9,000	
Other Rigs (3)	210,000	57,000	153,000		
Total	$ 4,082,000	$ 368,000	$ 1,521,000	$ 1,138,000	$ 1,055,000

(1) Represents the three-month period beginning October 1, 2016.

(2) Contract drilling backlog as of October 1, 2016 for our ultra-deepwater floaters includes (i) $213.0 million and $214.0 million for the years 2017 and 2018, respectively, and $214.0 million in the aggregate for the years 2019 to 2020, attributable to future work for the *Ocean GreatWhite*, which is contracted to BP, and (ii) $37.7 million, $149.4 million and $119.2 million for the years 2016, 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.

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

The following table reflects the percentage of rig days committed by year as of October 1, 2016. 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, including cold-stacked rigs, multiplied by the number of days in a particular year).

	For the Years Ending December 31,			
	2016 (1)	2017	2018	2019 - 2020
Rig Days Committed (2)				
Ultra-Deepwater Floaters	53%	59%	57%	27%
Deepwater Floaters	44%	37%	2%	
Other Rigs (3)	18%	14%		

(1) Represents the three-month period beginning October 1, 2016.

(2) As of October 1, 2016, includes no currently known, scheduled shipyard days for surveys and extended maintenance projects for the remainder of 2016 or for the year 2017.

(3) Includes committed days for our mid-water floater and jack-up rigs.

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

Regulatory Surveys, Planned Downtime and Regulatory Compliance. 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. 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

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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. During the first nine months of 2016, we capitalized interest of $15.2 million related to the construction of the *Ocean GreatWhite* and will continue capitalizing interest on this project until it is ready to begin working for BP, which we expect to occur in the fourth quarter of 2016. We will also commence depreciation of the *Ocean GreatWhite* in the fourth quarter of 2016.

Critical Accounting Policies

Our significant accounting policies are discussed in Note 1 of our notes to audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2015. There were no material changes to these policies during the nine months ended September 30, 2016.

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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 among all our divisions and locations, including the nature of services provided and the type of customers for our services. 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.

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
REVENUE EARNING DAYS (1)				
Floaters:				
Ultra-Deepwater	481	786	1,566	1,945
Deepwater	218	379	618	1,066
Mid-Water	181	241	543	1,253
Jack-ups		172	149	817
UTILIZATION (2)				
Floaters:				
Ultra-Deepwater	48%	71%	52%	62%
Deepwater	34%	59%	32%	56%
Mid-Water	33%	31%	29%	39%
Jack-ups		31%	11%	50%
AVERAGE DAILY REVENUE (3)				
Floaters:				
Ultra-Deepwater	$ 451,800	$ 478,800	$ 483,700	$ 484,900
Deepwater	303,000	360,700	311,200	428,400
Mid-Water	311,200	288,500	295,900	273,600
Jack-ups		96,700	202,700	89,900

(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 September 30, 2016, our cold-stacked rigs included four ultra-deepwater semisubmersibles, three deepwater semisubmersibles and three mid-water semisubmersibles. In addition, we have four jack-up rigs that are currently being marketed for sale and two semisubmersible rigs that have been retired. In October 2016, we sold one of our retired rigs for scrap and expect to complete the sale of the remaining retired rig by the end of 2016.

(3)

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

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

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(In thousands)			
CONTRACT DRILLING REVENUE				
Floaters:				
Ultra-Deepwater	$ 217,275	$ 376,195	$ 757,338	$ 943,261
Deepwater	66,011	136,668	192,319	456,542
Mid-Water	56,350	69,500	160,716	342,783
Total Floaters	339,636	582,363	1,110,373	1,742,586
Jack-ups		16,673	30,195	73,469
Total Contract Drilling Revenue	$ 339,636	$ 599,036	$ 1,140,568	$ 1,816,055
REVENUES RELATED TO REIMBURSABLE EXPENSES	$ 9,542	$ 10,706	$ 67,900	$ 47,775
CONTRACT DRILLING EXPENSE				
Floaters:				
Ultra-Deepwater	$ 124,099	$ 156,107	$ 375,020	$ 472,131
Deepwater	36,226	67,630	118,511	217,769
Mid-Water	17,634	35,784	67,380	201,839
Total Floaters	177,959	259,521	560,911	891,739
Jack-ups	1,833	12,507	14,764	54,950
Other	6,862	5,916	22,156	24,782
Total Contract Drilling Expense	$ 186,654	$ 277,944	$ 597,831	$ 971,471
REIMBURSABLE EXPENSES	$ 7,965	$ 10,476	$ 51,283	$ 46,904
OPERATING INCOME (LOSS)				
Floaters:				
Ultra-Deepwater	$ 93,176	$ 220,088	$ 382,318	$ 471,130
Deepwater	29,785	69,038	73,808	238,773
Mid-Water	38,716	33,716	93,336	140,944
Total Floaters	161,677	322,842	549,462	850,847
Jack-ups	(1,833)	4,166	15,431	18,519
Other	(6,862)	(5,916)	(22,156)	(24,782)
Reimbursable expenses, net	1,577	230	16,617	871
Depreciation	(86,473)	(118,086)	(295,729)	(378,714)
General and administrative expense	(15,237)	(16,888)	(48,774)	(50,888)
Gain (loss) on disposition of assets	1,222	(794)	2,265	(19)

Impairment of assets		(2,546)	(678,145)	(361,074)
Restructuring and separation costs		(1,574)		(8,735)
Total Operating Income (Loss)	$ 54,071	$ 181,434	$ (461,029)	$ 46,025
Other income (expense):				
Interest income	150	629	592	1,796
Interest expense, net of amounts capitalized	(19,032)	(21,350)	(68,704)	(70,800)
Foreign currency transaction (loss) gain	(712)	(1,163)	(7,833)	954
Other, net	269	217	(11,199)	702
Income (loss) before income tax (expense) benefit	34,746	159,767	(548,173)	(21,323)
Income tax (expense) benefit	(20,819)	(23,345)	59,588	(7,578)
NET INCOME (LOSS)	$ 13,927	$ 136,422	$ (488,585)	$ (28,901)

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Overview

Three Months Ended September 30, 2016 and 2015

Operating Income (Loss). Operating results for the third quarter of 2016 decreased $127.4 million compared to the same period of 2015, primarily due to lower utilization of our fleet, partially offset by a $31.6 million decrease in depreciation expense. Asset impairments in 2015 and 2016 lowered our depreciable asset base, reducing depreciation expense recorded during the third quarter of 2016, compared to the prior year quarter.

Contract drilling revenue and expense decreased $259.4 million and $91.3 million, respectively, during the third quarter of 2016, compared to the third quarter of 2015, due to continued low demand for contract drilling services, resulting in an aggregate 698-day decrease in revenue earning days for our drilling fleet. The decline in contract drilling expense reflected lower costs for labor and personnel ($61.4 million), mobilization of rigs ($18.0 million), shorebase and operational support ($7.1 million) and a net decrease in other rig operating costs and overhead costs ($16.8 million, including reductions in costs for repairs and maintenance, revenue-based agency fees, freight and rig stacking costs). Reduced contract drilling expense in the third quarter of 2016 was partially offset by expenses associated with our Pressure Control by the Hour™, or PCbtH, program currently employed on three of our drillships.

Income Tax (Expense) Benefit. Our effective tax rate for the three months ended September 30, 2016 was 59.9%, compared to a 14.8% effective tax rate for the three months ended September 30, 2015. The effective tax rate in the 2016 period was higher than in the same period of 2015 primarily due to the mix of our domestic and international pre-tax earnings and losses as well as return to provision adjustments of approximately $6 million in the current period.

Nine Months Ended September 30, 2016 and 2015

Operating Income (Loss). Operating results for the first nine months of 2016 decreased $507.1 million compared to the same period of 2015, primarily due to additional impairment losses recognized in 2016 ($317.1 million incremental loss) combined with the negative impact of lower utilization of our rig fleet. These negative effects on operating income were partially offset by an $83.0 million decrease in depreciation expense. Depreciation expense decreased primarily due to a lower depreciable asset base in 2016, compared to the first nine months of 2015, as a result of asset impairments taken in 2015 and in the second quarter of 2016.

Contract drilling revenue decreased $675.5 million, or 37%, during the first nine months of 2016, compared to the same period of 2015, primarily as a result of an aggregate of 2,205 fewer revenue earning days across our entire fleet, combined with the negative effect of lower average daily revenue earned, primarily by our deepwater floaters.

Total contract drilling expense decreased $373.6 million, or 38%, during the first nine months of 2016, compared to the same period of 2015, reflecting our lower cost structure due to additional rigs idled, cold stacked or retired during 2015 and in 2016, as well as the favorable impact of our cost control initiatives. The reduction in contract drilling expense during the first nine months of 2016 included lower expense, primarily for labor and personnel ($188.2 million), repairs and maintenance ($50.2 million), amortized mobilization costs ($44.3 million), shorebase and operational support costs ($35.9 million), freight ($13.9 million), revenue-based agency fees ($13.7 million), inspections ($10.4 million), and other rig operating costs ($37.1 million), including rig stacking costs and late start penalties recognized in 2015. Contract drilling expense for the first nine months of 2016 included incremental costs associated with our PCbtH program.

Impairment of Assets. During the first nine months of 2015, we recognized an aggregate impairment loss of $361.1 million with respect to the carrying values of our older drillship, the *Ocean Clipper*, seven mid-water floaters and one jack-up rig. During the first nine months of 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 Notes 1, 2 and 3 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

Restructuring and Separation Costs. During the first quarter of 2015, in response to the decline in the offshore drilling market, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, which resulted in the recognition of $8.7 million in restructuring and other employee separation related costs during the first nine months of 2015.

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 Benefit (Expense). Our effective tax rate for the nine months ended September 30, 2016 was 10.9%, compared to an 8.7% effective tax rate for the nine months ended September 30, 2015. The effective tax rate in the 2016 period was higher than in the same period of 2015, primarily due to the mix of our domestic and international pre-tax earnings and losses, as well as a $61.1 million valuation allowance for current and prior year foreign tax credits recorded in the current period.

Contract Drilling Revenue and Expense by Equipment Type

Three Months Ended September 30, 2016 and 2015

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters decreased $158.9 million during the third quarter of 2016, compared to the same period of 2015, primarily as a result of 305 fewer revenue earning days ($145.9 million) and lower average daily revenue earned ($13.0 million). Revenue earning days in the third quarter of 2016 decreased, primarily due to fewer revenue earning days for rigs under contract during the 2015 period that have subsequently been cold stacked (168 days), the *Ocean Clipper*, which was sold in November 2015 (88 days), the *Ocean BlackRhino*, which is currently between contracts (88 days), and unplanned downtime for contracted rigs (40 days), including downtime associated with an unplanned retrieval of a blowout preventer on one of our drillships. The decrease in revenue earning days was partially offset by 81 incremental revenue earning days for the *Ocean BlackLion*, which was placed in service in the third quarter of 2015. Average daily revenue decreased during the third quarter of 2016, compared to the prior year period, primarily due to a lower dayrate earned by the *Ocean Courage*.

Contract drilling expense for our ultra-deepwater floaters decreased $32.0 million during the third quarter of 2016, compared to the third quarter of 2015, primarily due to reduced costs for our cold-stacked ultra-deepwater rigs, including the retired *Ocean Clipper* and the deferral of costs associated with contract preparation activities for the *Ocean BlackRhino*. Contract drilling expense in the third quarter of 2016 reflected lower expense for labor and personnel ($32.3 million), mobilization of rigs ($15.7 million), repairs and maintenance ($3.1 million), revenue-based agency fees ($2.4 million), freight ($1.3 million) and other contract drilling expense ($9.7 million). Cost reductions in the third quarter of 2016 were partially offset by costs associated with the PCbtH program in effect on three of our drillships and incremental contract drilling expense for the *Ocean BlackLion* ($20.5 million).

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $70.7 million in the third quarter of 2016, compared to the same quarter in 2015, primarily due to 161 fewer revenue earning days ($58.1 million) combined with lower average daily revenue earned ($12.6 million) during the current year quarter. Revenue earning days decreased for the third quarter of 2016 primarily due to incremental downtime associated with cold-stacked rigs that had previously operated during the third quarter of 2015 (200 additional days) and the *Ocean Valiant*, which completed its contract in August 2016 and is now preparing for its next contract (44 additional days), partially offset by incremental revenue earning days for the *Ocean Apex*, which began operating under contract in the second quarter of 2016 (91 incremental days). Average daily revenue decreased during the third quarter of 2016, compared to the prior year period, primarily due to a lower dayrate earned by the *Ocean Valiant*.

Contract drilling expense incurred by our deepwater floaters decreased $31.4 million during the third quarter of 2016, compared to the same period of 2015, primarily due to reduced operating costs for our cold-stacked deepwater rigs ($35.4 million), partially offset by incremental contract drilling expense for our three active rigs.

Mid-Water Floaters. Revenue generated by our mid-water floaters decreased $13.2 million in the third quarter of 2016, compared to the same quarter in 2015, primarily due to 60 fewer revenue earning days ($17.3 million), partially offset by higher average daily revenue earned ($4.1 million). Revenue earnings days decreased in the third quarter of 2016 due to the absence of revenue earning days for rigs that have been retired (94 fewer days), partially offset by the absence of planned downtime associated with the *Ocean Guardian* s survey during the prior year quarter (36 incremental days). Since the first quarter of 2015, we have sold ten mid-water floaters, reducing our mid-water fleet to five drilling rigs, three of which are currently cold stacked, and two rigs that are under contract until various times in 2017. One additional mid-water rig, the *Ocean Quest,* has been retired and is expected to be sold in the fourth quarter of 2016.

Contract drilling expense for our mid-water floaters decreased $18.2 million in the third quarter of 2016, compared to the prior year quarter, primarily due to reduced operating costs for our cold-stacked and retired mid-water rigs ($16.1 million).

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $16.7 million and $10.7 million, respectively, during the third quarter of 2016, compared to the same period of 2015. We had no jack-up rigs under contract during the third quarter of 2016, compared to two rigs under contract in the third quarter of 2015. The *Ocean Scepter* is scheduled to commence operations under a new contract in Mexico beginning in the first quarter of 2017. Our four remaining jack-up rigs are being marketed for sale.

Nine Months Ended September 30, 2016 and 2015

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters during the first nine months of 2016 decreased $185.9 million compared to the same period of 2015, primarily as a result of an aggregate of 379 fewer revenue earning days ($184.0 million). Revenue earning days for the first nine months of 2016 decreased primarily due to 752 fewer revenue earning days for rigs that had operated during the first nine months of 2015 and are now cold stacked, as well as the *Ocean Clipper*, which was sold in late 2015. The aggregate decrease in revenue earning days was partially offset by incremental revenue earning days for the *Ocean BlackLion, w*hich began operating under contract after the third quarter of 2015 (186 days), and the *Ocean Monarch*, which was warm stacked during the 2015 period (181 days).

Excluding our newbuild drillships, contract drilling expense for our ultra-deepwater floaters decreased $97.1 million during the first nine months of 2016, compared to the same period of 2015, reflecting lower expense for labor and personnel ($78.6 million), maintenance and inspections ($32.3 million), mobilization ($22.7 million), shorebase and operational support ($11.2 million), freight ($7.5million), revenue-based agency fees ($6.6 million), and other rig operating and overhead costs ($9.7 million). These reductions in contract drilling expense were primarily due to lower costs for our cold-stacked rigs and the retired *Ocean Clipper*, as well as cost reduction initiatives implemented in 2015. Incremental contract drilling expense for our four drillships operating in the GOM was $71.5 million.

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $264.2 million in the first nine months of 2016, compared to the same period in 2015, primarily due to 448 fewer revenue earning days ($191.8 million), combined with a lower average daily revenue earned ($72.4 million). Revenue earning days for the first nine months of 2016 decreased primarily due to the cold stacking of three rigs that had operated during the first nine months of 2015 (686 fewer days), partially offset by incremental revenue earning days for rigs with contracts that commenced in the middle of the second quarter of 2015 and in 2016 (238 additional days). Average daily revenue decreased as a result of lower amortized mobilization and contract preparation fees recognized in the first nine months of 2016 compared to the same period in 2015 ($21.7 million), combined with lower dayrates earned by the *Ocean Valiant* and *Ocean Apex* during 2016.

Contract drilling expense incurred by our deepwater floaters decreased $99.3 million during the first nine months of 2016, compared to the same period of 2015, primarily due to a net reduction in costs for labor and personnel ($41.3 million), mobilization of rigs ($20.6 million), repairs and maintenance ($14.6 million), shorebase and operational support ($9.5 million), revenue-based agency fees ($4.1 million) and other operating costs ($9.2 million), primarily as a result of the cold stacking of rigs.

Mid-Water Floaters. Revenue generated by our mid-water floaters during the first nine months of 2016 decreased $182.1 million compared to the same period in 2015, primarily due to 710 fewer revenue earning days ($194.2 million), partially offset by higher average daily revenue ($12.1 million). Comparing the periods, only three of our mid-water floaters operated during both periods.

Contract drilling expense for our mid-water floaters decreased $134.5 million in the first nine months of 2016, compared to the prior year period, reflecting lower costs for labor and personnel ($64.6 million), maintenance and repairs ($14.5 million), shorebase and operational support ($15.8 million), mobilization ($7.6 million), cold stacking of rigs ($6.0 million), penalties ($5.7 million), inspections ($5.3 million) and other ($15.0 million).

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $43.3 million and $40.2 million, respectively, during the first nine months of 2016 compared to the prior year period. Revenue earning days decreased by 668 days due to the cold stacking of four rigs that operated under contract during the 2015 period and an early contract termination for the *Ocean Scepter* in 2016.

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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. See Credit Agreement.

Based on our cash available for current operations and contractual backlog of $4.1 billion as of October 1, 2016, of which $368.0 million is expected to be realized during the last quarter of 2016, we believe any additional capital expenditures in 2016 will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations Rig Construction.

Certain of our international rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or 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. 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 September 30, 2016 and December 31, 2015, we had cash available for current operations as follows:

	September 30, 2016	December 31, 2015
	(In thousands)	
Cash and cash equivalents	$ 81,329	$ 119,028
Marketable securities	46	11,518
Total cash available for current operations	$ 81,375	$ 130,546

A substantial portion of our cash flows has been invested in the enhancement of our drilling fleet. 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 make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments thereto if required. See Cash Flow, Capital Expenditures and Contractual Obligations Capital Expenditures.

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. On February 8, 2016, we announced that we would discontinue our quarterly regular cash dividend. During the nine-month period ended September 30, 2015, we paid regular cash dividends totaling $51.4 million.

Depending on market and other conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We did not purchase any shares of our outstanding common stock during the nine-month periods ended September 30, 2016 and 2015.

During the nine-month period ended September 30, 2016, our primary source of cash was an aggregate $492.0 million generated by operating activities, $157.5 million from the sale and leaseback of certain equipment on three of our drillships, and $10.0 million in proceeds from the sale of one jack-up rig and two mid-water floaters. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations - Pressure Control by the Hour. Cash usage during the same period was primarily for capital expenditures aggregating $598.2 million, including the final payment to Hyundai Heavy Industries Co., Ltd., or HHI, for the *Ocean GreatWhite* and $104.5 million for the net repayment of borrowings under our Credit Agreement.

During the nine-month period ended September 30, 2015, our primary source of cash was an aggregate $466.7 million generated from operating activities, $493.0 million from short-term borrowings under our commercial paper program and $8.4 million from the disposition of assets, including $5.4 million in proceeds from the sale of eight mid-water floaters for scrap during the period. Cash usage during the same period was primarily $758.3 million towards the construction of new rigs and our ongoing rig equipment enhancement/replacement program, including the final construction installment on the *Ocean BlackLion*, $250.0 million for debt repayment and $52.3 million for the payment of dividends and anti-dilution adjustments to stock plan participants.

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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, Capital Expenditures and Contractual Obligations

Our cash flow from operations and capital expenditures for the nine-month periods ended September 30, 2016 and 2015 were as follows:

	Nine Months Ended September 30,	
	2016	2015
	(In thousands)	
Cash flow from operations	$ 491,994	$ 466,677
Cash capital expenditures:		
Drillship construction	$	$ 416,095
Major upgrade of deepwater floaters		34,632
Construction of ultra-deepwater floater	477,749	37,129
Ocean Patriot enhancement project		1,349
Ocean Confidence service-life extension project		74,956
Rig equipment and replacement programs	120,487	194,181
Total capital expenditures	$ 598,236	$ 758,342

Cash Flow. Cash flow from operations increased approximately $25.3 million during the first nine months of 2016, compared to the first nine months of 2015, primarily due to a net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, repairs and maintenance, and other rig operating costs ($499.0 million), partially offset by lower cash receipts for contract drilling services ($490.3 million). The decline in both cash receipts and cash payments related to the performance of contract drilling services reflects the continued decline in contract drilling activity during the nine-month period ended September 30, 2016, as well as the positive results of our continuing efforts to control costs.

Capital Expenditures. We currently expect total capital expenditures for 2016 to aggregate approximately $625.0 million, including construction costs for the *Ocean GreatWhite* and our ongoing capital maintenance and replacement programs. As of September 30, 2016, we had incurred capital expenditures of $582.0 million during 2016, including accrued expenditures. See Contractual Cash Obligations Rig Construction. We are currently assessing our capital spending requirements for 2017 and have not yet approved a capital program for 2017.

Contractual Cash Obligations - Rig Construction. Shipyard construction of the *Ocean GreatWhite*, a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig, has been completed. In June 2016, we funded the final payment to HHI totaling $402.5 million in final settlement of the contract price for the *Ocean GreatWhite* The *Ocean GreatWhite* was delivered by the shipyard in mid-July 2016.

Contractual Cash Obligations - Pressure Control by the Hour. During the first nine months of 2016, we executed three sale and leaseback transactions with respect to well control equipment on the *Ocean BlackHawk, Ocean BlackHornet* and *Ocean BlackLion*. Future commitments under the operating leases and contractual services agreements for these rigs are estimated to be approximately $49.0 million per year or an aggregate $491.0 million over the term of the agreements. We expect to complete the remaining sale and leaseback transaction for the *Ocean BlackRhino* in the fourth quarter of 2016. See Note 13 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

We had no other purchase obligations for major rig upgrades or any other significant obligations at September 30, 2016, except for those related to our direct rig operations, which arise during the normal course of business.

Other Obligations. As of September 30, 2016, the total unrecognized tax benefits related to uncertain tax positions was $102.2 million. In addition, we have recorded a liability, as of September 30, 2016, for potential penalties and interest of $42.6 million and $2.5 million, respectively. 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.

Credit Agreement

At September 30, 2016, we had $182.1 million in borrowings outstanding under our Credit Agreement, and we were in compliance with all covenants thereunder. As of October 27, 2016, we had $221.5 million in borrowings outstanding and an additional $1.28 billion available under our Credit Agreement to provide short-term liquidity for our payment obligations.

Credit Ratings

In February 2016, Moody s Investors Service downgraded our senior unsecured credit rating to Ba2 from Baa2, with a stable outlook, and also downgraded our short-term credit rating to sub-prime. In July 2016, S&P Global Ratings (formerly Standard & Poor s Ratings Services) downgraded our senior unsecured credit rating to BBB from BBB+; the outlook remains negative.

Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered. 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. We no longer obtain a short-term credit rating from either rating agency.

Other Commercial Commitments - Letters of Credit

We were contingently liable as of September 30, 2016 in the amount of $57.2 million under certain performance, tax, supersedeas and customs bonds and letters of credit. Agreements relating to approximately $54.1 million of performance, tax, supersedeas, court and customs bonds can require collateral at any time. As of September 30, 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.

		For the Years Ending December 31,			
	Total	2016	2017	2018	2020
	(In thousands)				
Other Commercial Commitments					
Performance bonds	$ 40,177	$	$ 16,754	$ 4,298	$ 19,125
Supersedeas bond	9,189	9,189			
Tax bond	5,139		5,139		

Other	2,684	1,420	875	389	
Total obligations	$ 57,189	$ 10,609	$ 22,768	$ 4,687	$ 19,125

Off-Balance Sheet Arrangements

At September 30, 2016 and December 31, 2015, we had no off-balance sheet debt or other off-balance sheet arrangements.

New Accounting Pronouncements

See Note 1 General Information to our unaudited consolidated financial statements included in Item 1 of Part I of this report for a discussion of recently issued accounting pronouncements.

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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, will be, will continue, will likely result, project, forecast, budget and similar expressions. In addition, any stat 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. 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;
- business strategy;
- competitive position, including without limitation, competitive rigs entering the market;
- expected financial position;
- cash flows and contract backlog;
- statements regarding the future term of the Petrobras drilling contract for the *Ocean Valor* and the enforcement of our rights under the contract;
- 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;
- timing and duration of required regulatory inspections for our drilling rigs;
- timing and cost of completion of rig upgrades, construction projects and other capital projects;
- delivery dates and drilling contracts related to rig conversion or upgrade projects, construction projects, other capital projects or rig acquisitions;
- scrapping retired rigs;
- assets held for sale;
- asset impairments and impairment evaluations;
- 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, those described or referenced under Risk Factors in Item 1A in our Annual Report on Form 10-K for the year ended December 31, 2015.

The risks and uncertainties referenced above 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

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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.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk.

There were no material changes in our market risk components for the nine months ended September 30, 2016. See Quantitative and Qualitative Disclosures About Market Risk included in Item 7A of our Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2015 for further information.

ITEM 4. Controls and Procedures.

We maintain a system of disclosure controls and procedures which are designed to ensure 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 ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to our management on a timely basis to allow 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 September 30, 2016. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of September 30, 2016.

There were no changes in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during our third fiscal quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings.

Information related to certain legal proceedings is included in Note 10 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

ITEM 1A. Risk Factors.

Our Annual Report on Form 10-K for the year ended December 31, 2015 includes a detailed discussion of certain material risk factors facing our company. No material changes have been made to such risk factors as of September 30, 2016.

ITEM 6. Exhibits.

See the Exhibit Index for a list of those exhibits filed or furnished herewith.

SIGNATURES

Pursuant to the requirements 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.

DIAMOND OFFSHORE DRILLING, INC.

(Registrant)

Date October 31, 2016	By: /s/ Kelly Youngblood Kelly Youngblood Senior Vice President and Chief Financial Officer
Date October 31, 2016	/s/ Beth G. Gordon Beth G. Gordon Controller (Chief Accounting Officer)

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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).
10.1*	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.
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.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

* Filed or furnished herewith.