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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2017

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [√] Accelerated filer [ ]

Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if a smaller reporting company)

Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. [ ]

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, 2017 Common stock, $0.01 par value per share 137,227,782 shares

DIAMOND OFFSHORE DRILLING, INC.

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QUARTER ENDED SEPTEMBER 30, 2017

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PART I. FINANCIAL INFORMATION
ITEM 1. Financial Statements.

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

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

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 276,686	$ 156,233
Accounts receivable, net of allowance for bad debts	271,390	247,028
Prepaid expenses and other current assets	97,803	102,146
Assets held for sale	2,598	400
Total current assets	648,477	505,807
Drilling and other property and equipment, net of accumulated depreciation	5,432,689	5,726,935
Other assets	117,062	139,135
Total assets	$ 6,198,228	$ 6,371,877
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 33,301	$ 30,242
Accrued liabilities	140,233	182,159
Taxes payable	7,436	23,898
Short-term borrowings	--	104,200
Total current liabilities	180,970	340,499
Long-term debt	1,971,852	1,980,884
Deferred tax liability	124,929	197,011
Other liabilities	115,715	103,349
Total liabilities	2,393,466	2,621,743
Commitments and contingencies (Note 8)		
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; 144,084,644 shares issued and 137,227,309 shares outstanding at September 30, 2017; 143,997,757 shares issued and 137,169,663 shares outstanding at December 31, 2016)	1,441	1,440
Additional paid-in capital	2,009,953	2,004,514
Retained earnings	1,996,438	1,946,765
Accumulated other comprehensive (loss) gain	(3)	1
Treasury stock, at cost (6,857,335 and 6,828,094 shares of common stock at September 30, 2017 and December 31, 2016, respectively)	(203,067)	(202,586)
Total stockholders' equity	3,804,762	3,750,134
Total liabilities and stockholders' equity	$ 6,198,228	$ 6,371,877

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

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share data)

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Revenues:				
Contract drilling	$ 357,683	$ 339,636	$ 1,113,410	$ 1,140,568
Revenues related to reimbursable expenses	8,340	9,542	26,128	67,900
Total revenues	366,023	349,178	1,139,538	1,208,468
Operating expenses:				
Contract drilling, excluding depreciation	198,072	186,654	597,812	597,831
Reimbursable expenses	8,220	7,965	25,488	51,283
Depreciation	83,281	86,473	262,492	295,729
General and administrative	17,806	15,237	54,299	48,774
Impairment of assets	--	--	71,268	678,145
Loss (gain) on disposition of assets	63	(1,222)	(2,085)	(2,265)
Total operating expenses	307,442	295,107	1,009,274	1,669,497
Operating income (loss)	58,581	54,071	130,264	(461,029)
Other income (expense):				
Interest income	776	150	1,347	592
Interest expense, net of amounts capitalized	(28,562)	(19,032)	(83,409)	(68,704)
Loss on extinguishment of senior notes	(35,366)	--	(35,366)	--
Foreign currency transaction loss	(677)	(712)	(517)	(7,833)
Other, net	1,447	269	1,322	(11,199)
(Loss) income before income tax benefit (expense)	(3,801)	34,746	13,641	(548,173)
Income tax benefit (expense)	14,600	(20,819)	36,646	59,588
Net income (loss)	$ 10,799	$ 13,927	$ 50,287	$ (488,585)
Earnings (loss) per share, Basic and Diluted	$ 0.08	$ 0.10	$ 0.37	$ (3.56)
Weighted-average shares outstanding:				
Shares of common stock	137,227	137,170	137,208	137,167
Dilutive potential shares of common stock	14	84	29	--
Total weighted-average shares outstanding	137,241	137,254	137,237	137,167

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

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income (loss)	$ 10,799	$ 13,927	$ 50,287	$ (488,585)
Other comprehensive (losses) gains, net of tax:				
Derivative financial instruments:				
Reclassification adjustment for gain included in net income (loss)	(1)	--	(4)	(3)
Investments in marketable securities:				
Unrealized holding loss	--	(1)	--	(6,559)
Reclassification adjustment for loss included in net income (loss)	--	--	--	11,600
Total other comprehensive (loss) gain	(1)	(1)	(4)	5,038
Comprehensive income (loss)	$ 10,798	$ 13,926	$ 50,283	$ (483,547)

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

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)
(In thousands)

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Operating activities:		
Net income (loss)	$ 50,287	$ (488,585)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation	262,492	295,729
Loss on impairment of assets	71,268	678,145
Loss on extinguishment of senior notes	35,366	--
Gain on disposition of assets	(2,085)	(2,265)
Loss on sale of marketable securities	--	12,146
Deferred tax provision	(73,873)	(114,405)
Stock-based compensation expense	4,806	3,754
Deferred income, net	8,379	(23,381)
Deferred expenses, net	32,701	(1,099)
Other assets, noncurrent	(2,806)	(677)
Other liabilities, noncurrent	(212)	3,021
Other	2,387	1,997
Changes in operating assets and liabilities:		
Accounts receivable	(25,743)	131,388
Prepaid expenses and other current assets	(4,831)	3,950
Accounts payable and accrued liabilities	17,787	(32,762)
Taxes payable	(9,288)	25,038
Net cash provided by operating activities	366,635	491,994
Investing activities:		
Capital expenditures (including rig construction)	(100,613)	(598,236)
Proceeds from disposition of assets, net of disposal costs	4,017	169,038
Proceeds from sale and maturities of marketable securities	31	4,603
Net cash used in investing activities	(96,565)	(424,595)
Financing activities:		
Redemption of senior notes	(500,000)	--
Payment of debt extinguishment costs	(34,395)	--
Proceeds from issuance of senior notes	496,360	--
Debt issuance costs and arrangement fees	(7,226)	--
Net repayment of short-term borrowings	(104,200)	(104,489)
Other	(156)	(609)
Net cash used in financing activities	(149,617)	(105,098)
Net change in cash and cash equivalents	120,453	(37,699)
Cash and cash equivalents, beginning of period	156,233	119,028
Cash and cash equivalents, end of period	$ 276,686	$ 81,329

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

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

The unaudited condensed 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, 2016 (File No. 1-13926).

As of October 26, 2017, Loews Corporation owned approximately 53% of the outstanding shares of our common stock.

Interim Financial Information

The accompanying unaudited condensed 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 condensed consolidated financial information has not been audited but, in the opinion of management, includes all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of Diamond Offshore's condensed 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.

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, 2017 and the year ended December 31, 2016, we capitalized $33.7 million and $177.6 million, respectively, in replacements and betterments of our drilling fleet. See Note 6.

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, a decision to retire, scrap or cold stack a rig, contracted backlog of less than one year for 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 assign 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.

Capitalized Interest

We capitalize interest cost for rig construction or upgrades, as well as other qualifying projects. A reconciliation of our total interest cost to "Interest expense, net of amounts capitalized" as reported in our Condensed Consolidated Statements of Operations is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
	(In thousands)			
Total interest cost, including amortization of debt issuance costs	$ 28,590	$ 27,016	$ 83,440	$ 83,888
Capitalized interest	(28)	(7,984)	(31)	(15,184)
Total interest expense as reported	$ 28,562	$ 19,032	$ 83,409	$ 68,704

Stock-Based Compensation

In March 2016, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2016-09, *Compensation - Stock Compensation (Topic 718)*, or ASU 2016-09. ASU 2016-09 requires that all excess tax benefits and tax deficiencies be recognized in the income statement as discrete tax items when share-based awards vest or are settled. The update also clarifies the statement of cash flows presentation for certain components of share-based awards and provides for a policy election to either estimate the number of awards expected to vest or account for forfeitures when they occur. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016 and was adopted by us on January 1, 2017.

The guidance requiring (i) excess tax benefits to be recorded in the condensed consolidated statement of operations, (ii) exclusion of excess tax benefits from the computation of assumed proceeds under the treasury stock method when calculating earnings per share, and (iii) presentation of excess tax benefits as an operating activity on the statement of cash flows, rather than as a financing activity, has been applied prospectively effective January 1, 2017. We have elected to account for forfeitures of share-based awards in the period in which such forfeitures occur rather than using an estimated forfeiture rate and have adopted this change using a modified retrospective approach, which resulted in a $0.6 million reduction in opening retained earnings. The impact to our Condensed Consolidated Balance Sheets is as follows:

	Retained Earnings	Additional Paid-in Capital
	(In thousands)	
Balance as of January 1, 2017 before adoption	$ 1,946,765	$ 2,004,514
Adjustment for making election to account for forfeitures as they occur	(634)	634
Balance as of January 1, 2017 after adoption	$ 1,946,131	$ 2,005,148

Recent Accounting Pronouncements

In October 2016, the FASB issued ASU No. 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*, or ASU 2016-16. ASU 2016-16 amends the guidance in Topic 740 with respect to the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017. We are currently evaluating our historical intra-group transactions for possible impact under the provisions of ASU 2016-16. The guidance in ASU 2016-16 will be applied effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard as an adjustment to opening retained earnings with an offset to a deferred income tax liability.

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 condensed consolidated statements of 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. We have determined that under the new standard, our drilling contracts contain a lease component and therefore we will be required to separately recognize revenues associated with the lease and services components. Additionally, for transactions in which we are considered lessees, we will recognize a lease liability and right of use asset based on our portfolio of leases as of the time of adoption. The guidance of ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period. Early adoption of ASU 2016-02 is permitted. We expect to adopt ASU 2016-02 on January 1, 2019 using the modified retrospective approach. We are currently reviewing the requirements of the accounting standard with regards to arrangements under which we are either the lessor or lessee, to determine the impact of ASU 2016-02 on our financial position, results of operations, cash flows and disclosures contained in the notes to our condensed consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, or ASU 2014-09. The new standard supersedes the industry-specific standards that currently exist under GAAP and provides a framework to address revenue recognition issues comprehensively for all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Under the new guidance, companies recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized and requires enhanced disclosures about revenue. In July 2015, the FASB issued ASU 2015-14, which deferred the effective date of ASU 2014-09. ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017. We plan to adopt ASU 2014-09 effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018 as an adjustment to opening retained earnings.

When applying the new standard, we plan to account for the integrated services provided within our drilling contracts as a single performance obligation composed of a series of distinct time increments, which will be satisfied over time. We will determine the total transaction price for each individual contract by estimating both fixed and variable consideration expected to be earned over the term of the contract. Consideration that does not relate to a distinct good or service, such as mobilization, demobilization, and contract preparation revenue, will be allocated across the single performance obligation and recognized ratably over the term of the contract. All other components of consideration within a contract, including the dayrate revenue, will continue to be recognized in the period when the services are performed. We expect our revenue recognition under ASU 2014-09 to differ from our current revenue recognition pattern only as it relates to demobilization revenue. Such revenue, which is recognized upon completion of a contract under current GAAP, will be estimated at contract inception and recognized over the term of the contract under the new guidance. Additionally, we expect that the cumulative effect adjustment to opening retained earnings required by the modified retrospective adoption approach will not be significant as it will primarily consist of the impact of the timing difference related to recognition of demobilization revenue for affected contracts. Not all contracts include a demobilization provision.

2. Impairment of Assets

During the third quarter of 2017, we evaluated six drilling rigs with indicators of impairment. 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 or a market recovery is delayed, we may be required to recognize additional impairment losses in future periods.

During the second quarter of 2017, we evaluated seven of our drilling rigs with indicators of impairment. Due to the continued deterioration of market fundamentals in the contract drilling industry, as well as newly-available market projections, which indicated that a full market recovery is likely to occur further in the future than had previously been estimated, we determined that the carrying values of one ultra-deepwater and one deepwater semisubmersible rig were impaired (we collectively refer to these two rigs as the 2017 Impaired Rigs).

We estimated the fair value of the 2017 Impaired Rigs using an income approach, whereby the fair value of each rig was estimated based on a calculation of the rig's future net cash flows. As described in Note 1, these calculations utilized significant unobservable inputs, including estimated proceeds that may be received on ultimate disposition of the rig, and are representative of Level 3 fair value measurements due to the significant level of estimation involved and lack of transparency as to the inputs used. During the second quarter of 2017, we recorded an impairment loss of $71.3 million related to our 2017 Impaired Rigs.

During the second quarter of 2016, we evaluated 15 of our drilling rigs with indicators of impairment. Based on our assumptions and analyses at that time, 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 2016 Impaired Rigs). During the second quarter of 2016, we recorded impairment losses of $670.0 million and $8.1 million related to our 2016 Impaired Rigs and related rig spare parts and supplies, respectively.

3. Supplemental Financial Information

Condensed Consolidated Balance Sheets Information

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

	September 30, 2017	December 31, 2016
	(In thousands)	
Trade receivables	$ 265,476	$ 236,040
Value added tax receivables	10,425	14,639
Related party receivables	119	149
Other	829	1,659
	276,849	252,487
Allowance for bad debts	(5,459)	(5,459)
Total	$ 271,390	$ 247,028

Prepaid expenses and other current assets consist of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Rig spare parts and supplies	$ 30,598	$ 25,343
Deferred rig start-up costs	52,544	61,488
Prepaid BOP lease	3,873	3,873
Prepaid insurance	3,808	3,771
Prepaid taxes	2,536	2,894
Other	4,444	4,777
Total	$ 97,803	$ 102,146

Accrued liabilities consist of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Rig operating expenses	$ 35,612	$ 33,732
Payroll and benefits	42,275	45,619
Deferred revenue	8,911	9,522
Accrued capital project/upgrade costs	3,338	60,308
Interest payable	36,813	18,365
Personal injury and other claims	5,160	6,424
Other	8,124	8,189
Total	$ 140,233	$ 182,159

Condensed Consolidated Statements of Cash Flows Information

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

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 3,338	$ 65,286
Common stock withheld for payroll tax obligations (1)	481	181
Cash interest payments (2)	60,253	53,433
Cash income taxes paid, net of (refunds):		
Foreign	37,884	33,479
State	94	1

(1) Represents the cost of 29,241 shares and 7,923 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, 2017 and 2016, respectively. These costs are presented as a deduction from stockholders' equity in "Treasury stock" in our Condensed Consolidated Balance Sheets at September 30, 2017 and 2016.

(2) Interest payments, net of amounts capitalized, were $60.2 million and $43.6 million for the nine-month periods ended September 30, 2017 and 2016, respectively.

4. Earnings Per Share

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

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands, except per share data)			
Net income (loss) – basic and diluted numerator	$ 10,799	$ 13,927	$ 50,287	$ (488,585)
Weighted average shares – basic (denominator):	137,227	137,170	137,208	137,167
Dilutive effect of stock-based awards	14	84	29	--
Weighted average shares including conversions – diluted (denominator)	137,241	137,254	137,237	137,167
Earnings (loss) per share:				
Basic	$ 0.08	$ 0.10	$ 0.37	$ (3.56)
Diluted	$ 0.08	$ 0.10	$ 0.37	$ (3.56)

The following table sets forth the share effects of stock-based awards excluded from our computations of diluted earnings per share, or EPS, for the periods presented:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)			
Employee and director:				
Stock options	--	6	1	8
Stock appreciation rights	1,297	1,469	1,330	1,519
Restricted stock units	1,061	423	977	687

5. 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, we do not believe that we have any significant concentrations of credit risk at September 30, 2017.

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 and U.S. Treasury bills and notes. Our Level 1 assets at September 30, 2017 consisted of cash held in money market funds of $242.2 million and time deposits of $20.6 million. Our Level 1 assets at December 31, 2016 consisted of cash held in money market funds of $125.7 million and time deposits of $20.6 million.

Level 2 Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities may include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter foreign currency forward exchange contracts. Our Level 2 assets at September 30, 2017 and December 31, 2016 consisted solely of residential mortgage-backed securities, which 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, 2017 and December 31, 2016 consisted of nonrecurring measurements of certain of our drilling rigs and associated spare parts and supplies for which we recorded impairment losses in the second quarter of 2017 and during 2016.

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 nine-month period ended September 30, 2017 or the year ended December 31, 2016.

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 each of the nine-month periods ended September 30, 2017 and 2016, of $71.3 million and $678.1 million, respectively.

Assets and liabilities measured at fair value are summarized below.

	September 30, 2017				
	Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Nine Months Ended
	(In thousands)				
Recurring fair value measurements:					
Assets:					
Short-term investments	$ 262,887	$ --	$ --	$ 262,887	
Mortgage-backed securities	--	4	--	4	
Total assets	$ 262,887	$ 4	$ --	$ 262,891	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets [(1)]	$ --	$ --	$ 2,000	$ 2,000	$ 71,268

(1) Represents the total book value as of September 30, 2017 of one ultra-deepwater rig and one deepwater semisubmersible rig, which were written down to their estimated recoverable amounts during the second quarter of 2017 and were reported as "Drilling and other property and equipment, net of accumulated depreciation," in our Condensed Consolidated Balance Sheets at September 30, 2017.

	December 31, 2016				
	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	$ 146,360	$ --	$ --	$ 146,360	
Mortgage-backed securities	--	35	--	35	
Total assets	$ 146,360	$ 35	$ --	$ 146,395	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets [(2)]	$ --	$ --	$ 69,153	$ 69,153	$ 678,145

(1) Represents impairment losses of $8.1 million and $670.0 million recognized during the year ended December 31, 2016 related to our rig spare parts and supplies and certain impaired rigs, respectively.

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

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 Condensed 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 term 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, 2017 and December 31, 2016. 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, 2017		December 31, 2016	
	Fair Value	**Carrying Value**	**Fair Value**	**Carrying Value**
	(In millions)			
5.875% Senior Notes due 2019	$ --	$ --	$ 518.6	$ 499.8
3.45% Senior Notes due 2023	225.0	249.3	215.0	249.3
7.875% Senior Notes due 2025	528.8	496.4	--	--
5.70% Senior Notes due 2039	411.3	497.1	392.5	497.1
4.875% Senior Notes due 2043	562.5	748.9	532.7	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.

See Note 7.

6. Drilling and Other Property and Equipment

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

	September 30, 2017	December 31, 2016
	(In thousands)	
Drilling rigs and equipment	$ 8,279,491	$ 8,950,385
Land and buildings	63,309	64,449
Office equipment and other	78,909	73,108
Cost	8,421,709	9,087,942
Less: accumulated depreciation	(2,989,020)	(3,361,007)
Drilling and other property and equipment, net	$ 5,432,689	$ 5,726,935

During the nine-month period ended September 30, 2017, we recognized an aggregate impairment loss of $71.3 million related to the 2017 Impaired Rigs. See Notes 1 and 2.

7. Senior Notes

In August 2017, we issued $500.0 million aggregate principal amount of unsecured 7.875% senior notes due 2025, or 2025 Notes, and received net proceeds of $489.1 million after deducting underwriting discounts, commissions and estimated expenses. The 2025 Notes bear interest at 7.875% per year and mature on August 15, 2025. Interest on the 2025 Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning February 15, 2018. We used the net proceeds from the 2025 Notes, together with cash on hand, to fund the redemption of our 5.875% senior notes due 2019, or 2019 Notes.

The 2025 Notes are unsecured obligations of Diamond Offshore Drilling, Inc., and rank equally in right of payment to all of its existing and future senior indebtedness, and are structurally subordinated to all existing and future obligations of our subsidiaries. We have the right to redeem some or all of the 2025 Notes at any time or from time to time, on at least 15 days but not more than 60 days prior written notice, at the applicable redemption price specified in the governing indenture, plus accrued and unpaid interest to, but excluding, the date of redemption. The 2025 Notes contain customary covenants including limitations on liens, mergers, consolidations and certain sales of assets and on entering into sale and lease-back transactions covering a drilling rig or drillship, as specified in the governing indenture.

In August 2017, we redeemed all of our outstanding 2019 Notes for a redemption price of $543.0 million in the aggregate, including accrued and unpaid interest to the date of redemption. We accounted for the redemption as an extinguishment of debt and have reported a corresponding loss of $35.4 million in our Condensed Consolidated Statements of Operations for the three-month and nine-month periods ended September 30, 2017.

At September 30, 2017, our outstanding senior notes were comprised of the following debt issues:

Debt Issue	Principal Amount (In millions)	Maturity Date	Interest Rate		Semiannual Interest Payment Dates
			Coupon	Effective	
3.45% Senior Notes due 2023	$250.0	November 1, 2023	3.45%	3.50%	May 1 and November 1
7.875% Senior Notes due 2025	$500.0	August 15, 2025	7.875%	8.00%	February 15 and August 15
5.70% Senior Notes due 2039	$500.0	October 15, 2039	5.70%	5.75%	April 15 and October 15
4.875% Senior Notes due 2043	$750.0	November 1, 2043	4.875%	4.89%	May 1 and November 1

At September 30, 2017, the carrying value of our outstanding senior notes, net of unamortized discount and debt issuance costs, was as follows:

	September 30, 2017
	(In thousands)
3.45% Senior Notes due 2023	$ 248,090
7.875% Senior Notes due 2025	489,200
5.70% Senior Notes due 2039	492,930
4.875% Senior Notes due 2043	741,632
Total senior notes, net	$ 1,971,852

8. 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.

Patent Litigation. We have been in discussions with Transocean Ltd., or Transocean, an offshore drilling contractor, with regard to United States patents previously owned by Transocean or its affiliates or employees pertaining to certain dual-activity drilling operations. On August 30, 2017, an affiliate of Transocean filed a lawsuit against us and one of our subsidiaries in the United States District Court for the Southern District of Texas, alleging that we infringed the Transocean patents by the unauthorized sale, offer for sale, and importation and use of four of our drilling rigs (*Ocean Blackhawk*, *Ocean BlackHornet*, *Ocean BlackRhino* and *Ocean BlackLion*). In its lawsuit, Transocean's affiliate is seeking unspecified monetary damages. The Transocean patents, which expired in May 2016, do not apply to drilling activities outside the United States or to activities that occurred after the expiration of the patents. We are unable to estimate our potential exposure, if any, to this lawsuit 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.

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 any claim, lawsuit or action cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of any litigation matter. Any claims against us, whether meritorious or not, could cause us to incur significant costs and expenses and require significant amounts of management and operational time and 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 under an overriding royalty interest in certain developmental oil-and-gas producing properties, or NPI, which we believe is a real property interest. Our drilling program related to the NPI was completed in 2011, and the balance of the amounts due to us under the NPI was received in 2013. However, in August 2012, the customer that conveyed the NPI to us filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code. Certain parties (including the debtor) in the bankruptcy proceedings questioned whether our NPI, and certain amounts we received under it after the filing of the bankruptcy, should be included in the debtor's estate under the bankruptcy proceeding. In 2013, we filed a declaratory judgment action in the bankruptcy court seeking a declaration that our NPI, and payments that we received from it after the filing of the bankruptcy, are not part of the bankruptcy estate. We agreed to a settlement with the company that purchased most of the debtor's assets (including the debtor's claims against our NPI) whereby the nature of our NPI will not be challenged by that party and our declaratory judgment action was dismissed. Following the settlement, the bankruptcy was converted to a Chapter 7 liquidation proceeding. Several lienholders who had previously intervened in the declaratory judgment action filed motions in the bankruptcy contending that their liens have priority and seeking disgorgement of $3.25 million of payments made to us after the bankruptcy was filed. We believe that our rights to the payments at issue are superior to these liens, and we filed motions to dismiss the claims. In November 2016, the court dismissed the lienholders' claims, and the lienholders are appealing the ruling. In addition, the bankruptcy trustee filed counterclaims seeking disgorgement of a total of $30.0 million of pre- and post-bankruptcy payments made to us under the original NPI. The bankruptcy court has dismissed all but one of the trustee's disgorgement claims, which is limited in amount to $17.0 million. In December 2016, the company that purchased most of the debtor's assets from bankruptcy also filed for bankruptcy. In October 2017, we reached agreement with the trustee to settle the remaining $17.0 million disgorgement claim for an immaterial amount. The settlement agreement has been submitted to the bankruptcy court for approval. We continue to 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, 2017, 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 U.S. 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, 2017 our estimated liability for personal injury claims was $31.2 million, of which $4.8 million and $26.4 million were recorded in "Accrued liabilities" and "Other liabilities," respectively, in our Condensed Consolidated Balance Sheets. At December 31, 2016 our estimated liability for personal injury claims was $32.9 million, of which $6.1 million and

$26.8 million were recorded in “Accrued liabilities” and “Other liabilities,” respectively, in our Condensed 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.

Letters of Credit and Other. We were contingently liable as of September 30, 2017 in the amount of $21.3 million under certain performance, tax, supersedeas, court and customs bonds and letters of credit. Agreements relating to approximately $15.6 million of tax, supersedeas, court and customs bonds can require collateral at any time. As of September 30, 2017, 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.

9. 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,	
	2017	2016	2017	2016
	(In thousands)			
Floaters:				
Ultra-Deepwater	$ 275,859	$ 217,275	$ 801,859	$ 757,338
Deepwater	35,634	66,011	170,482	192,319
Mid-Water	39,616	56,350	124,444	160,716
Total Floaters	351,109	339,636	1,096,785	1,110,373
Jack-ups	6,574	--	16,625	30,195
Total contract drilling revenues	357,683	339,636	1,113,410	1,140,568
Revenues related to reimbursable expenses	8,340	9,542	26,128	67,900
Total revenues	$ 366,023	$ 349,178	$ 1,139,538	$ 1,208,468

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, 2017, our active drilling rigs were located offshore in five countries in addition to the United States. Revenues by geographic area are presented by attributing revenues to the individual country or areas where the services were performed.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)			
United States	$ 171,476	$ 121,895	$ 481,933	$ 414,087
International:				
South America	58,750	105,614	272,929	333,803
Australia/Asia	80,543	56,688	219,103	169,323
Europe	48,680	63,117	148,948	253,287
Mexico	6,574	1,864	16,625	37,968
Total revenues	$ 366,023	$ 349,178	$ 1,139,538	$ 1,208,468

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 condensed consolidated financial statements (including the notes thereto) included in Item 1 of Part I of this report and our audited consolidated financial statements (including 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, 2016. References to "Diamond Offshore," "we," "us" or "our" mean Diamond Offshore Drilling, Inc., a Delaware corporation, and its subsidiaries.

We provide contract drilling services to the energy industry around the globe with a fleet of 19 offshore drilling rigs, excluding five semisubmersible rigs that we plan to retire and scrap in the near future. These retired units, which are currently cold stacked, include the *Ocean Baroness*, *Ocean Alliance*, *Ocean Vanguard*, *Ocean Nomad* and *Ocean Princess*. As of the date of this report, our current fleet consists of four drillships, 14 semisubmersibles and one jack-up rig. The *Ocean Monarch*, which had been in a shipyard for a survey and contract modifications since the first quarter of 2017, began operating under the first of three contracts in Australia late in the second quarter of 2017. In addition to the five rigs to be scrapped, six of our rigs are currently cold stacked, consisting of three ultra-deepwater and three deepwater semisubmersible rigs. See "– Contract Drilling Backlog."

Market Overview

At the end of the third quarter of 2017, the spot price for Brent crude oil was $57.54 per barrel and had been fluctuating within a general range of $45-$58 per barrel throughout the first nine months of 2017. This day-to-day volatility in oil price is attributable to multiple factors, including fluctuations in the current and expected level of global oil inventories and estimates of global oil demand, production cuts by the Organization of the Petroleum Exporting Countries (which have been extended until the end of the first quarter of 2018) and the impact of hurricanes and tropical storms in the U.S. Gulf of Mexico. In addition, some U.S. shale producers have resumed drilling and production activities due to their ability to quickly and more cheaply bring oil reserves to production and therefore benefit from modestly-improved commodity prices. This has prevented crude oil prices from rising through typical supply and demand economics to a more sustainable level for offshore exploration and development. As a result, capital spending for offshore exploration and development continued to decline in 2017, with annual capital spending estimated by some industry analysts to be up to 20% lower than reduced 2016 capital spending levels. If these market estimates are realized, it would represent three consecutive years of decline in offshore spending.

Some industry analysts have predicted that the downturn is leveling off; however, the offshore drilling market has been slow to recover and is not yet at the recovery stage. Customer inquiries and new tenders have increased during 2017, compared to 2016, but are for offshore drilling opportunities in 2018 and beyond. Competition among offshore drillers remains intense as rig supply exceeds demand, despite the cold stacking and retirement or scrapping of over 100 rigs since 2014. Additionally, based on industry data as of the date of this report, more than 30 floater rigs currently remain on order, with scheduled deliveries from 2017 through 2021. The majority of these rigs are not currently contracted for future work, which further increases competition.

Dayrates continue to be depressed and, in some cases, have been negotiated at break-even or below cost levels in order to enable drilling contractors to recover a portion of operating costs for rigs that would otherwise be uncontracted or cold stacked. Discussions with our customers indicate a preference for "hot" rigs rather than the reactivation of cold-stacked rigs. This preference incentivizes drilling contractors to accept lower rates for the sole purpose of maintaining their rigs in an active state and allowing for at least partial cost recovery. Some industry analysts have predicted that demand for drilling rigs in the offshore market will slowly improve, but utilization growth may not be significant enough to impact dayrates for some time.

As a result of the continued pessimistic outlook for the offshore drilling industry in the near term, certain of our customers, as well as those of our competitors, have attempted to renegotiate or terminate existing drilling contracts. Such renegotiations have included requests to lower the contract dayrate, in some cases in exchange for additional contract term, shorten the term on one contracted rig in exchange for additional term on another rig, terminate a contract in exchange for a lump sum payout and many other possibilities. In addition to the potential for renegotiations, some of our drilling contracts permit the customer to terminate the contract early after specified notice periods, usually resulting in a requirement for the customer to pay a contractually specified termination amount, which may not fully compensate us for the loss of the contract. Some of our 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.

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. When we cold stack or expect to scrap a rig, we evaluate the rig for impairment. See "–Contract Drilling Backlog" for future commitments of our rigs during 2017 through 2020.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of October 1, 2017 (based on information available at that time), January 1, 2017 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2016), and October 1, 2016 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016). 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 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*. We do not believe that Petrobras had a valid or lawful basis for terminating the contract and in August 2016, we filed a lawsuit in Brazil, claiming that Petrobras' purported termination of the contract was unlawful and requested 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 appealed the granting of the injunction, but in March 2017, the court ruled against Petrobras' appeal and upheld the injunction. As a result of the favorable ruling, both the injunction and the *Ocean Valor* contract remain in effect. Petrobras has filed an appeal of the ruling to the Superior Court of Justice. We intend to continue to defend our rights under the contract, which is estimated to conclude in accordance with its terms in October 2018. However, litigation is inherently unpredictable, and there can be no assurance as to the ultimate outcome of this matter. The rig is currently on standby earning a reduced dayrate.

	October 1, 2017	January 1, 2017	October 1, 2016
		(In thousands)	
Contract Drilling Backlog			
Ultra-Deepwater Floaters [(1)]	$ 2,413,000	$ 3,215,000	$ 3,614,000
Deepwater Floaters	86,000	197,000	258,000
Other Rigs [(2)]	118,000	152,000	210,000
Total	$ 2,617,000	$ 3,564,000	$ 4,082,000

(1) Contract drilling backlog as of October 1, 2017 for our ultra-deepwater floaters includes $156.8 million for 2017 and 2018 attributable to contracted work for the *Ocean Valor* under the contract that Petrobras has attempted to terminate, which is currently in effect pursuant to an injunction granted by a Brazilian court.

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

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

	For the Years Ending December 31,				
	Total	2017 (1)	2018	2019	2020
	(In thousands)				
Contract Drilling Backlog					
Ultra-Deepwater Floaters (2)	$ 2,413,000	$ 290,000	$ 1,109,000	$ 845,000	$ 169,000
Deepwater Floaters	86,000	32,000	54,000	--	--
Other Rigs (3)	118,000	13,000	42,000	45,000	18,000
Total	$ 2,617,000	$ 335,000	$ 1,205,000	$ 890,000	$ 187,000

(1) Represents the three-month period beginning October 1, 2017.

(2) Contract drilling backlog as of October 1, 2017 for our ultra-deepwater floaters includes $37.7 million and $119.2 million for the years 2017 and 2018, respectively, attributable to contracted work for the *Ocean Valor* under the contract that Petrobras has attempted to terminate, which is currently in effect pursuant to an injunction granted by a Brazilian court.

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

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

	For the Years Ending December 31,			
	2017 (1)	2018	2019	2020
Rig Days Committed (2)				
Ultra-Deepwater Floaters	62%	63%	47%	9%
Deepwater Floaters	33%	16%	--	--
Other Rigs (3)	15%	18%	17%	6%

(1) Represents the three-month period beginning October 1, 2017.
(2) As of October 1, 2017, includes approximately 60 and 35 currently known, scheduled shipyard days for contract preparation, mobilization of rigs, surveys and extended maintenance projects for the remainder of 2017 and for the year 2018, respectively.
(3) Includes committed days for our mid-water floaters and jack-up rig.

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

Regulatory Surveys and Planned Downtime. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a special survey, that are due every five years for most of our rigs. The inspection interval for our North Sea rigs is two-and-one-half years. During the remainder of 2017, we expect to spend approximately 60 days for a special survey for the *Ocean Patriot* after completion of its current contract. In addition, we expect to spend approximately 35 days in 2018 for contract preparation and the mobilization of the *Ocean Monarch* in connection with a future contract offshore Victoria, Australia. 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, 2017, 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, 2017, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, and generally covering liabilities arising out of or relating to pollution and/or environmental risk. We believe that the policy limit for our marine liability insurance is within the range that is customary for companies of our size in the offshore drilling industry and is appropriate for our business. Our deductibles for marine liability coverage related to insurable events arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for other marine liability coverage, including personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, are $10.0 million for the first occurrence and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

Capitalization of Interest. We capitalize interest cost for rig construction or upgrades, as well as other qualifying projects, in accordance with accounting principles generally accepted in the U.S. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use. The capitalization period ends when the asset is substantially complete and ready for its intended use. During 2016, we ceased capitalizing interest related to the construction of the *Ocean GreatWhite* and do not currently have any ongoing rig construction projects for which we capitalized interest costs during the first nine months of 2017. At this time, we expect the capitalization of interest costs to be minimal in 2017, relating primarily to qualifying software development projects.

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, 2016. There were no material changes to these policies during the nine months ended September 30, 2017.

Results of Operations

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

Key performance indicators by equipment type are listed below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
REVENUE-EARNING DAYS [(1)]				
Floaters:				
Ultra-Deepwater	678	481	1,867	1,566
Deepwater	183	218	691	618
Mid-Water	123	181	395	543
Jack-ups	88	--	222	149
UTILIZATION [(2)]				
Floaters:				
Ultra-Deepwater	61%	48%	57%	52%
Deepwater	33%	34%	42%	32%
Mid-Water	27%	33%	29%	29%
Jack-ups	95%	--	60%	11%
AVERAGE DAILY REVENUE [(3)]				
Floaters:				
Ultra-Deepwater	$ 407,200	$ 451,800	$ 429,500	$ 483,700
Deepwater	194,500	303,000	246,500	311,200
Mid-Water	322,100	311,200	315,000	295,900
Jack-ups	75,000	--	74,900	202,700

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

(2) Utilization is calculated as the ratio of total revenue-earning days divided by the total calendar days in the period for all specified rigs in our fleet (including cold-stacked rigs, but excluding rigs under construction). As of September 30, 2017, our cold-stacked rigs included three ultra-deepwater and three deepwater semisubmersible rigs. In addition, one previously cold-stacked jack-up rig was sold in April 2017.

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

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

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In thousands)			
CONTRACT DRILLING REVENUE				
Floaters:				
Ultra-Deepwater	$ 275,859	$ 217,275	$ 801,859	$ 757,338
Deepwater	35,634	66,011	170,482	192,319
Mid-Water	39,616	56,350	124,444	160,716
Total Floaters	351,109	339,636	1,096,785	1,110,373
Jack-ups	6,574	--	16,625	30,195
Total Contract Drilling Revenue	$ 357,683	$ 339,636	$ 1,113,410	$ 1,140,568
REVENUE RELATED TO REIMBURSABLE EXPENSES	$ 8,340	$ 9,542	$ 26,128	$ 67,900
CONTRACT DRILLING EXPENSE				
Floaters:				
Ultra-Deepwater	$ 139,619	$ 124,099	$ 418,153	$ 375,020
Deepwater	27,139	36,226	91,559	118,511
Mid-Water	17,753	17,634	52,791	67,380
Total Floaters	184,511	177,959	562,503	560,911
Jack-ups	6,197	1,833	18,498	14,764
Other	7,364	6,862	16,811	22,156
Total Contract Drilling Expense	$ 198,072	$ 186,654	$ 597,812	$ 597,831
REIMBURSABLE EXPENSES	$ 8,220	$ 7,965	$ 25,488	$ 51,283
OPERATING INCOME (LOSS)				
Floaters:				
Ultra-Deepwater	$ 136,240	$ 93,176	$ 383,706	$ 382,318
Deepwater	8,495	29,785	78,923	73,808
Mid-Water	21,863	38,716	71,653	93,336
Total Floaters	166,598	161,677	534,282	549,462
Jack-ups	377	(1,833)	(1,873)	15,431
Other	(7,364)	(6,862)	(16,811)	(22,156)
Reimbursable expenses, net	120	1,577	640	16,617
Depreciation	(83,281)	(86,473)	(262,492)	(295,729)
General and administrative expense	(17,806)	(15,237)	(54,299)	(48,774)
Impairment of assets	--	--	(71,268)	(678,145)
(Loss) gain on disposition of assets	(63)	1,222	2,085	2,265
Total Operating Income (Loss)	$ 58,581	$ 54,071	$ 130,264	$ (461,029)
Other income (expense):				
Interest income	776	150	1,347	592
Interest expense, net of amounts capitalized	(28,562)	(19,032)	(83,409)	(68,704)
Foreign currency transaction loss	(677)	(712)	(517)	(7,833)
Loss on extinguishment of senior notes	(35,366)	--	(35,366)	--
Other, net	1,447	269	1,322	(11,199)
(Loss) income before income tax benefit	(3,801)	34,746	13,641	(548,173)
Income tax benefit (expense)	14,600	(20,819)	36,646	59,588
NET INCOME (LOSS)	$ 10,799	$ 13,927	$ 50,287	$ (488,585)

Overview

Three Months Ended September 30, 2017 and 2016

Operating Income (Loss). Total operating income for the third quarter of 2017 increased $4.5 million, or 8%, compared to the same period of 2016, primarily due to incremental contract drilling revenue of $18.0 million, partially offset by higher contract drilling expense of $11.4 million. Comparing the two quarters, contract drilling revenue increased primarily due to an aggregate 192 incremental revenue-earning days for our rigs ($73.8 million), partially offset by lower overall average daily revenue earned ($55.8 million). The increase in contract drilling expense during the third quarter of 2017 was primarily the result of incremental operating costs for the *Ocean GreatWhite* ($9.3 million), which began operating during the first quarter of 2017, and the *Ocean BlackRhino* ($17.1 million) and *Ocean Scepter* ($4.8 million), both of which operated during the third quarter of 2017, compared to the third quarter of 2016 when they did not operate. The increase in total contract drilling expense for our fleet was partially offset by a net $19.8 million reduction in other rig operating and overhead costs, primarily due to the cold stacking of the *Ocean Victory* and the sale of six retired rigs subsequent to the third quarter of 2016. In addition, we continue to see favorable results from our cost control measures that were initiated in prior periods.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $9.5 million during the third quarter of 2017 compared to the third quarter of 2016, primarily as a result of the absence of interest capitalized during construction of the *Ocean GreatWhite* in the 2016 period ($8.0 million). In addition, we incurred incremental interest expense of $1.4 million in the third quarter of 2017 related to the issuance of our 7.875% senior notes due 2025, or 2025 Notes, and redemption of our 5.875% senior notes due 2019, or 2019 Notes, in August 2017.

Loss on Extinguishment of Senior Notes. During the third quarter of 2017, we recorded a $35.4 million loss on extinguishment of our outstanding 2019 Notes.

Income Tax Benefit. We recorded a net income tax benefit of $14.6 million for the third quarter of 2017, compared to net income tax expense of $(20.8) million for the third quarter of 2016. The difference in the amount of income tax benefit (expense) recognized in the 2017 period, compared to the prior year period, was in large part due to the mix of our domestic and international pre-tax earnings and losses, inclusive of the loss on extinguishment of debt recognized in the third quarter of 2017. Income tax expense for the third quarter of 2016 included approximately $6.0 million in expense attributable to return to provision adjustments related to prior period tax returns.

Nine Months Ended September 30, 2017 and 2016

Operating Income (Loss). Total operating income for the first nine months of 2017 increased $591.3 million compared to the same period of 2016, primarily due to a lower impairment loss recognized in the 2017 period ($606.9 million) and reduced depreciation expense ($33.2 million). These favorable variances were partially offset by the unfavorable effect of a $27.2 million decrease in contract drilling revenue during the first nine months of 2017, compared to the same period of 2016, and the absence of $14.6 million in net reimbursable revenue earned by the *Ocean Endeavor* during the 2016 period. Depreciation expense decreased primarily due to a lower depreciable asset base in the 2017 period, compared to the first nine months of 2016, as a result of asset impairments recognized in 2016 and 2017.

Contract drilling revenue decreased $27.2 million during the first nine months of 2017 compared to the first nine months of 2016, primarily as a result of lower average daily revenue earned by multiple rigs in our fleet, partially offset by the favorable impact of an aggregate 299 incremental revenue-earning days. Comparing the two nine-month periods, total contract drilling expense for our fleet was flat.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $14.7 million during the first nine months of 2017 compared to the same period of 2016, primarily as a result of the absence of $15.2 million in capitalized interest for construction projects during the 2016 period. The increase in interest expense is also attributable to incremental interest expense of $1.4 million related to the issuance of our 2025 Notes and redemption of our 2019 Notes in August 2017, which was offset by reduced interest expense associated with lower borrowings under our revolving credit agreement ($1.8 million).

Impairment of Assets. During the first nine months of 2017, we recognized an aggregate impairment loss of $71.3 million compared to an aggregate impairment charge of $678.1 million during the first nine months of 2016. See Notes 1 and 2 to our unaudited condensed consolidated financial statements included in Item 1 of Part I of this report.

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

Income Tax Benefit. We recorded a net income tax benefit of $36.6 million and $59.6 million for the nine months ended September 30, 2017 and 2016, respectively. The difference in the amount of income tax benefit recognized in the first nine months of 2017, compared to the prior year period, was primarily due to the mix of our domestic and international pre-tax earnings and losses, inclusive of the impairment losses recognized in 2017 and 2016 and a loss on extinguishment of debt recognized in the 2017 period. Tax benefit for the first nine months of 2017 and 2016 included U.S. tax benefits of $24.9 million and $143.2 million, respectively, related to the impairment of assets in the U.S. tax jurisdiction. Income tax benefit for the nine months ended September 30, 2016 was net of additional tax expense associated with a valuation allowance of $61.1 million recognized during the period for current and prior year tax assets associated with foreign tax credits and return to provision adjustments of approximately $6.0 million.

Contract Drilling Revenue and Expense by Equipment Type

Three Months Ended September 30, 2017 and 2016

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $58.6 million during the third quarter of 2017, compared to the same quarter of 2016, primarily as a result of 197 incremental revenue-earning days ($88.7 million), partially offset by lower average daily revenue earned ($30.1 million). Revenue-earning days increased during the third quarter of 2017, primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (92 days) and the *Ocean BlackRhino* (91 days), neither of which was operating under contract during the third quarter of 2016, combined with an aggregate of 14 incremental revenue-earning days for our other ultra-deepwater rigs. Average daily revenue decreased during the third quarter of 2017, compared to the prior year quarter, primarily due to a lower dayrate earned by the *Ocean Monarch* under a new contract that commenced in the second quarter of 2017.

Contract drilling expense for our ultra-deepwater floaters increased $15.5 million during the third quarter of 2017, compared to the same period in 2016, primarily due to incremental contract drilling expense for the *Ocean GreatWhite* ($9.3 million) and *Ocean BlackRhino* ($17.1 million), as well as higher costs associated with the mobilization of rigs ($3.4 million). These incremental costs were partially offset by lower costs for labor and personnel ($3.3 million), repairs and maintenance ($4.4 million), shorebase support and overhead ($3.5 million) and other costs ($3.1 million).

Deepwater Floaters. Revenue and contract drilling expense for our deepwater floaters decreased $30.4 million and $9.1 million, respectively, in the third quarter of 2017 compared to the same quarter in 2016. The reduction in revenue was primarily the result of cold stacking the *Ocean Victory* in the second quarter of 2017 after completion of its contract in Trinidad ($34.3 million), partially offset by 45 incremental revenue-earning days for the *Ocean Valiant* during the third quarter of 2017, which operated at a lower average dayrate than in the prior year period ($1.9 million). Contract drilling expense for the third quarter of 2017 also declined, primarily due to reduced costs incurred by the *Ocean Victory* ($8.6 million).

Mid-Water Floaters. Revenue generated by our mid-water floaters during the third quarter of 2017 decreased $16.7 million compared to the same quarter of 2016, primarily due to the warm stacking of the *Ocean Guardian* between contracts for much of the third quarter of 2017 ($16.1 million). Contract drilling expense remained flat during the third quarter of 2017, compared to the prior year period.

Jack-ups. The *Ocean Scepter*, which was cold-stacked throughout the third quarter of 2016, returned to service under a new contract offshore Mexico in early 2017 and generated contract revenue and incurred incremental contract drilling expense of $6.6 million and $4.8 million, respectively, during the third quarter of 2017.

Nine Months Ended September 30, 2017 and 2016

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $44.5 million during the first nine months of 2017, compared to the same period of 2016, primarily as a result of 301 incremental revenue-earning days ($145.6 million), partially offset by lower average daily revenue earned ($101.1 million). Revenue-earning days increased primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (260 days) and the *Ocean BlackRhino,* which was warm-stacked for much of the prior year period (184 days), and fewer days associated with downtime for repairs (56 days). The increase in 2017 revenue-earning days was partially offset by incremental downtime for the *Ocean Monarch*, which was in the shipyard for a survey and contract modifications during the first half of 2017 (121 days), and the absence of revenue-earning days for cold-stacked rigs that had worked in the prior year period (78 days). Average daily revenue decreased during the 2017 period, primarily due to the absence of $40.0 million in demobilization revenue recognized in 2016 for the *Ocean Endeavor*, combined with the effect of lower dayrates earned under new contracts for both the *Ocean Monarch* and *Ocean BlackRhino*.

Contract drilling expense for our ultra-deepwater floaters increased $43.1 million during the first nine months of 2017, compared to the same period of 2016, primarily due to incremental costs associated with the Pressure Control by the Hour® program on our drillships ($24.8 million) and incremental contract drilling expense for the *Ocean GreatWhite* ($31.4 million). These incremental costs for our ultra-deepwater floaters were partially offset by a net $13.1 million decrease in contract drilling expense during the first nine months of 2017, compared to the prior year period, primarily due to lower expenses for our cold-stacked rigs ($14.3 million).

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $21.8 million in the first nine months of 2017, compared to the same period in 2016, primarily due to a reduction in average daily revenue earned ($44.7 million), partially offset by the effect of 73 incremental revenue-earning days ($22.9 million). Average daily revenue decreased during the first nine months of 2017 primarily as a result of a lower dayrate being earned by the *Ocean Valiant* under its current contract in the North Sea that commenced in the fourth quarter of 2016. Revenue-earning days increased primarily due to 180 incremental days for our active deepwater floaters, partially offset by 107 fewer days for the cold-stacked *Ocean Victory*, which had been under contract during the 2016 period.

Contract drilling expense for our deepwater floaters decreased $27.0 million during the first nine months of 2017, compared to the 2016 period, primarily due to a net reduction in costs associated with labor and personnel ($8.7 million), maintenance and repairs ($9.2 million), equipment rental ($2.3 million), freight ($1.2 million) and other rig operating and overhead costs ($5.6 million) attributable to various factors, including the cold stacking of rigs and implementation of cost control measures for our working rigs and shorebase operations in 2016.

Mid-Water Floaters. Revenue and contract drilling expense for our mid-water floaters decreased $36.3 million and $14.6 million, respectively, during the first nine months of 2017 compared to the same period of 2016. The decrease in revenue reflected 148 fewer revenue-earning days ($43.8 million), partially offset by an increase in average daily revenue earned ($7.5 million). The decrease in revenue-earning days primarily related to the completion of the final contract for the *Ocean Ambassador* in March 2016 prior to the rig being sold (78 days) and fewer days for the *Ocean Guardian*, which was warm stacked between contracts for much of the 2017 period (75 days). Only two of our mid-water floaters operated during both periods, while the remainder of our mid-water fleet remained cold stacked or was sold during 2016. The decrease in contract drilling expense was primarily due to reduced costs related to the *Ocean Ambassador* ($8.5 million), and a reduction in labor and personnel ($4.2 million) and other costs ($1.9 million) for the remainder of the fleet.

Jack-ups. Contract drilling revenue attributable to our current and previously-owned jack-up rigs decreased $13.6 million during the first nine months of 2017, compared to the same period in 2016. The *Ocean Scepter*, which had been idle since completion of its former contract offshore Mexico in 2016, commenced operations offshore Mexico in early 2017 at a lower dayrate than previously earned, and resulted in an $8.6 million reduction in contract drilling revenue, compared to the prior year period. In addition, we recognized $4.9 million in loss-of-hire insurance proceeds during the first nine months of 2016. Contract drilling expense for our jack-up rigs increased $3.7 million during the first nine months of 2017, compared to the 2016 period, primarily due to higher costs incurred by the *Ocean Scepter* for labor and personnel ($2.7 million) and repairs ($2.6 million), partially offset by reduced costs associated with sold rigs ($1.6 million).

Liquidity and Capital Resources

We principally rely on our cash flows from operations and cash reserves to meet our liquidity needs. We 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 $2.6 billion as of October 1, 2017, of which $0.3 billion is expected to be realized during the remainder of 2017, we believe future capital spending and debt service requirements will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See "– Sources and Uses of Cash – Capital Expenditures."

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. Although we do not intend to repatriate the earnings of DFAC, and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practical to estimate this potential liability.

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, 2017 and December 31, 2016, we had cash available for current operations, including cash reserves of DFAC, as follows:

	September 30, 2017	December 31, 2016
	(In thousands)	
Cash and cash equivalents	$ 276,686	$ 156,233
Marketable securities	4	35
Total cash available for current operations	$ 276,690	$ 156,268

A substantial portion of our cash flows has historically 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 also make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments thereto if required. See "– Sources and Uses of Cash – Capital Expenditures."

We pay dividends at the discretion of our Board of Directors, or Board, and any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board's consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs and other factors that our Board considers relevant at that time. We did not pay any dividends in 2016 or during the first nine months of 2017.

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, 2017 and 2016.

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.

Sources and Uses of Cash

During the nine-month period ended September 30, 2017, our primary sources of cash were an aggregate $489.1 million in net proceeds from the issuance of our 2025 Notes, $366.6 million generated by operating activities and $4.0 million from the disposition of assets. Cash usage during the same period was primarily $534.4 million for the redemption of our 2019 Notes, $104.2 million for the net repayment of borrowings under our Credit Agreement and capital expenditures aggregating $100.6 million. See "– Senior Notes."

Our cash flow from operations and capital expenditures for the nine-month periods ended September 30, 2017 and 2016 were as follows:

	Nine Months Ended September 30,	
	2017	2016
	(In thousands)	
Cash flow from operations	$ 366,635	$ 491,994
Cash capital expenditures:		
Construction of ultra-deepwater floater	$ --	$ 477,749
Rig equipment and replacement programs	100,613	120,487
Total capital expenditures	$ 100,613	$ 598,236

Cash Flow from Operations. Cash flow from operations decreased $125.4 million during the first nine months of 2017, compared to the first nine months of 2016, primarily due to lower cash receipts for contract drilling services ($193.3 million), partially offset by a net decrease in cash payments for contract drilling expenses, including personnel-related, repairs and maintenance and overheads ($72.4 million). The decline in both cash receipts and cash payments related to the performance of contract drilling services reflects continuing depressed market conditions in the offshore drilling industry, as well as positive results of our continuing focus on controlling costs.

Capital Expenditures. As of the date of this report, we expect total capital expenditures for 2017 to aggregate approximately $125.0 million for our ongoing capital maintenance and replacement programs.

We had no other purchase obligations for major rig upgrades at September 30, 2017.

Other Obligations. As of September 30, 2017, the total net unrecognized tax benefits related to uncertain tax positions was $65.0 million. 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, 2017, we had no borrowings outstanding under our Credit Agreement, and were in compliance with all covenants thereunder. As of October 26, 2017, we had $1.5 billion available under our Credit Agreement to provide liquidity for our payment obligations.

Senior Notes

In August 2017, we issued $500.0 million aggregate principal amount of unsecured 2025 Notes and received net proceeds of $489.1 million after deducting underwriting discounts, commissions and estimated expenses. The 2025 Notes bear interest at 7.875% per year and mature on August 15, 2025. Interest on the 2025 Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning February 15, 2018.

We used the net proceeds from the 2025 Notes, together with cash on hand, to fund the redemption of our 5.875% senior notes due 2019. See Note 7 "Senior Notes" to our unaudited condensed consolidated financial statements included in Item 1 of Part 1 of this report.

Credit Ratings

On October 18, 2017, S&P Global Ratings, or S&P, downgraded our corporate credit rating to B+ from BB-; our outlook by S&P remains negative. On July 28, 2017, Moody's Investor Services downgraded our corporate credit rating to Ba3 with a negative outlook from Ba2 with a stable outlook. Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered. Any 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 funds by issuing 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.

Other Commercial Commitments - Letters of Credit

We were contingently liable as of September 30, 2017 in the amount of $21.3 million under certain performance, tax, supersedeas, bid and customs bonds and letters of credit. Agreements relating to approximately $15.6 million of tax, supersedeas, court and customs bonds can require collateral at any time. As of September 30, 2017, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. Banks have issued letters of credit on our behalf securing certain of these bonds. The table below provides a list of these obligations in U.S. dollar equivalents and their time to expiration.

	Total	For the Years Ending December 31, 2017	2018
	(In thousands)		
Other Commercial Commitments			
Performance bonds	$ 1,000	$ --	$ 1,000
Supersedeas bond	9,189	9,189	--
Tax bond	5,852	--	5,852
Bid bond	3,200	--	3,200
Other	2,040	1,310	730
Total obligations	$ 21,281	$ 10,499	$ 10,782

Off-Balance Sheet Arrangements

At September 30, 2017 and December 31, 2016, we had no off-balance sheet debt or other off-balance sheet arrangements.

New Accounting Pronouncements

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

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

- market conditions and the effect of such conditions on our future results of operations;
- sources and uses of and requirements for financial resources and sources of liquidity;
- contractual obligations and future contract negotiations;
- interest rate and foreign exchange risk;
- operations outside the United States;
- business strategy;
- growth opportunities;
- competitive position, including without limitation, competitive rigs entering the market;
- expected financial position;
- cash flows and contract backlog;
- future term of the Petrobras drilling contract for the *Ocean Valor* and the enforcement of our rights under the contract;
- idling drilling rigs or reactivating stacked rigs;
- declaration and payment of regular or special dividends;
- financing plans;
- market outlook;
- tax planning;
- debt levels and the impact of changes in the credit markets and credit ratings for our debt;

- budgets for capital and other expenditures;
- timing and duration of required regulatory inspections for our drilling rigs;
- timing and cost of completion of capital projects;
- delivery dates and drilling contracts related to capital projects or rig acquisitions;
- plans and objectives of management;
- idling drilling rigs or reactivating stacked rigs;
- scrapping retired rigs;
- assets held for sale;
- asset impairments and impairment evaluations;
- our internal controls and remediation of our material weakness in internal control over financial reporting;
- outcomes of disputes and 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, 2016.

The risks and uncertainties referenced above are not exhaustive. Other sections of this report and our other filings with the Securities and Exchange Commission 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. While we believe that each of these reports is reliable, we have not independently verified the information included in such reports. 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, 2017. See “Quantitative and Qualitative Disclosures About Market Risk” included in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2016 for further information.

ITEM 4. Controls and Procedures.

We maintain a system of disclosure controls and procedures that 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, 2017. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of September 30, 2017.

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 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings.

Information related to certain legal proceedings is included in Note 8 to our unaudited condensed 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, 2016 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, 2017.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Items 2(a) and 2(b) are not applicable.

(c) During the three months ended September 30, 2017, in connection with the vesting of restricted stock units held by our officers and certain of our employees, which were awarded under an equity incentive compensation plan, we acquired shares of our common stock in satisfaction of tax withholding obligations that were incurred on the vesting date. The date of acquisition, number of shares and average effective acquisition price per share were as follows:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Acquired	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 1, 2017 through July 31, 2017	1,173	$10.83	N/A	N/A
August 1, 2017 through August 31, 2017	--	--	N/A	N/A
September 1, 2017 through September 30, 2017	--	--	N/A	N/A
Total	1,173	$10.83	N/A	N/A

In July 2017, 318 shares of our common stock that we had acquired in April 2017 in satisfaction of tax withholding obligations related to the vesting of restricted stock units, which were included in the shares we reported in Item 2 of Part II of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, were released to an employee due to an adjustment in the employee’s tax withholdings.

ITEM 6. Exhibits.

Exhibit No.	Description of Exhibit
3.1	Amended and Restated Certificate of Incorporation of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003) (SEC File No. 1-13926).
3.2	Amended and Restated By-laws (as amended through October 4, 2013) of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 8, 2013).
4.1	Indenture, dated as of February 4, 1997, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York Mellon which was previously known as The Bank of New York) (as successor under the Base Indenture to The Chase Manhattan Bank), as Trustee (incorporated by reference to Exhibit 4.1 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2001) (SEC File No. 1-13926).
4.2	Ninth Supplemental Indenture, dated as of August 15, 2017, between Diamond Offshore Drilling, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed August 16, 2017).
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.

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 30, 2017	By:	/s/ Kelly Youngblood Kelly Youngblood Senior Vice President and Chief Financial Officer
Date	October 30, 2017		/s/ Beth G. Gordon Beth G. Gordon Vice President and Controller (Chief Accounting Officer)