DIAMOND OFFSHORE DRILLING INC
Form 10-Q
May 04, 2015
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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 March 31, 2015

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 x No ¨

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

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

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

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

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

As of April 24, 2015 Common stock, $0.01 par value per share 137,158,706 shares

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements.

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share and per share data)

	March 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 184,775	$ 233,623
Marketable securities	14,016	16,033
Accounts receivable, net of allowance for bad debts	445,685	463,862
Prepaid expenses and other current assets	199,321	185,541
Total current assets	843,797	899,059
Drilling and other property and equipment, net of accumulated depreciation	6,574,142	6,945,953
Other assets	117,890	176,277
Total assets	$ 7,535,829	$ 8,021,289
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 102,869	$ 138,444
Accrued liabilities	383,525	426,592
Taxes payable	34,685	41,648
Current portion of long-term debt	249,979	249,962
Total current liabilities	771,058	856,646
Long-term debt	1,994,587	1,994,526
Deferred tax liability	413,009	530,394
Other liabilities	177,329	188,160
Total liabilities	3,355,983	3,569,726
Commitments and contingencies (Note 9)		
Stockholders equity:		
Preferred stock (par value $0.01, 25,000,000 shares authorized, none issued and outstanding)		
	1,440	1,440

Common stock (par value $0.01, 500,000,000 shares authorized; 143,978,877 shares issued and 137,158,706 shares outstanding at March 31, 2015; 143,960,260 shares issued and 137,147,899 shares outstanding at December 31, 2014)		
Additional paid-in capital	1,995,634	1,993,898
Retained earnings	2,389,145	2,661,999
Accumulated other comprehensive gain (loss)	(3,968)	(3,605)
Treasury stock, at cost (6,820,171 and 6,812,361 shares of common stock at March 31, 2015 and December 31, 2014, respectively)	(202,405)	(202,169)
Total stockholders equity	4,179,846	4,451,563
Total liabilities and stockholders equity	$ 7,535,829	$ 8,021,289

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share data)

	Three Months Ended March 31,	
	2015	**2014**
Revenues:		
Contract drilling	$ 599,577	$ 685,308
Revenues related to reimbursable expenses	20,479	24,116
Total revenues	620,056	709,424
Operating expenses:		
Contract drilling, excluding depreciation	350,658	369,790
Reimbursable expenses	20,092	23,666
Depreciation	137,299	107,011
General and administrative	17,452	22,827
Impairment of assets	358,528	
Restructuring and separation costs	6,168	
Gain on disposition of assets	(611)	(147)
Total operating expenses	889,586	523,147
Operating (loss) income	(269,530)	186,277
Other income (expense):		
Interest income	583	408
Interest expense, net of amounts capitalized	(23,982)	(18,155)
Foreign currency transaction gain (loss)	5,590	(1,178)
Other, net	221	327
(Loss) income before income tax benefit (expense)	(287,118)	167,679
Income tax benefit (expense)	31,409	(21,869)
Net (loss) income	$ (255,709)	$ 145,810
(Loss) earnings per share, Basic and Diluted	$ (1.86)	$ 1.05
Weighted-average shares outstanding:		
Shares of common stock	137,151	138,469
Dilutive potential shares of common stock		4

Total weighted-average shares outstanding	137,151	138,473
Cash dividends declared per share of common stock	$ 0.125	$ 0.875

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(Unaudited)

(In thousands)

	Three Months Ended March 31,	
	2015	**2014**
Net (loss) income	$ (255,709)	$ 145,810
Other comprehensive (losses) gains, net of tax:		
Derivative financial instruments:		
Unrealized holding (loss) gain	(1,827)	2,839
Reclassification adjustment for loss (gain) included in net income	3,587	(177)
Investments in marketable securities:		
Unrealized holding (loss) gain	(2,123)	38
Reclassification adjustment for gain included in net income		(8)
Total other comprehensive (loss) gain	(363)	2,692
Comprehensive (loss) income	$ (256,072)	$ 148,502

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Three Months Ended March 31,	
	2015	**2014**
Operating activities:		
Net (loss) income	$ (255,709)	$ 145,810
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	137,299	107,011
Loss on impairment of assets	358,528	
Restructuring and separation costs	6,168	
Gain on disposition of assets	(611)	(147)
Loss (gain) on foreign currency forward exchange contracts	6,390	(511)
Deferred tax provision	(118,332)	4,997
Accretion of discounts on marketable securities	(117)	(144)
Stock-based compensation expense	856	1,417
Deferred income, net	(3,874)	1,384
Deferred expenses, net	(46,027)	(26,044)
Long-term employee remuneration programs	36	2,048
Other assets, noncurrent	506	(173)
Other liabilities, noncurrent	(2,262)	155
(Payments for) proceeds from settlement of foreign currency forward exchange contracts designated as accounting hedges	(6,390)	511
Bank deposits denominated in nonconvertible currencies	561	5,016
Other	565	572
Changes in operating assets and liabilities:		
Accounts receivable	18,177	53,178
Prepaid expenses and other current assets	11,997	2,961
Accounts payable and accrued liabilities	(18,006)	10,176
Taxes payable	70,811	(5,202)
Net cash provided by operating activities	160,566	303,015
Investing activities:		
Capital expenditures (including rig construction)	(197,032)	(595,314)
Proceeds from disposition of assets, net of disposal costs	4,763	173
Proceeds from sale and maturities of marketable securities	11	2,175,021
Purchases of marketable securities		(1,599,914)
Net cash provided by (used in) investing activities	(192,258)	(20,034)

Financing activities:		
Payment of dividends	(17,144)	(122,655)
Purchase of treasury stock		(86,364)
Other	(12)	(833)
Net cash used in financing activities	(17,156)	(209,852)
Net change in cash and cash equivalents	(48,848)	73,129
Cash and cash equivalents, beginning of period	233,623	347,011
Cash and cash equivalents, end of period	$ 184,775	$ 420,140

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

The unaudited consolidated financial statements of Diamond Offshore Drilling, Inc. and subsidiaries, which we refer to as Diamond Offshore, we, us or our, should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 1-13926).

As of April 24, 2015, Loews Corporation owned 53.1 % of the outstanding shares of our common stock.

Interim Financial Information

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the U.S., or GAAP, for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission. Accordingly, pursuant to such rules and regulations, they do not include all disclosures required by GAAP for complete financial statements. The consolidated financial information has not been audited but, in the opinion of management, includes all adjustments (consisting only of normal recurring accruals) necessary for a fair presentation of the 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.

Cash and Cash Equivalents

We consider short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash to be cash equivalents. We had bank deposits denominated in Egyptian pounds totaling $6.8 million and $7.3 million at March 31, 2015 and December 31, 2014, respectively. However, the local currency is not readily convertible into U.S. dollars or other currencies at this time. We expect to use a portion of these amounts to fund local obligations in Egyptian pounds in the short term and have reported $6.7 million and $7.2 million, representing the excess of total bank deposits over our estimated local currency requirements for the next twelve months, as Other assets in our Consolidated Balance Sheets at March 31, 2015 and December 31, 2014, respectively.

The effect of exchange rate changes on cash balances held in foreign currencies was not material for each of the three-month periods ended March 31, 2015 and 2014.

Marketable Securities

We classify our investments in marketable securities as available for sale and they are stated at fair value in our Consolidated Balance Sheets. Accordingly, any unrealized gains and losses, net of taxes, are reported in our Consolidated Balance Sheets in Accumulated other comprehensive gain (loss), or AOCGL, until realized. The cost of debt securities is adjusted for amortization of premiums and accretion of discounts to maturity and such adjustments are included in our Consolidated Statements of Operations in Interest income. The sale and purchase of securities are recorded on the date of the trade. The cost of debt securities sold is based on the specific identification method. Realized gains or losses, as well as any declines in value that are judged to be other than temporary, are reported in our Consolidated Statements of Operations in Other income (expense) Other, net. See Note 5.

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Derivative Financial Instruments

Our derivative financial instruments consist primarily of foreign currency forward exchange, or FOREX, contracts which we may designate as cash flow hedges. In accordance with GAAP, each derivative contract is stated in the balance sheet at its fair value with gains and losses reflected in the income statement except that, to the extent the derivative qualifies for and is designated as an accounting hedge, the gains and losses are reflected in income in the same period as offsetting gains and losses on the qualifying hedged positions. Designated hedges are expected to be highly effective, and therefore, adjustments to record the carrying value of the effective portion of our derivative financial instruments to their fair value are recorded as a component of AOCGL in our Consolidated Balance Sheets. The effective portion of the cash flow hedge will remain in AOCGL until it is reclassified into earnings in the period or periods during which the hedged transaction affects earnings or it is determined that the hedged transaction will not occur. We report such realized gains and losses as a component of Contract drilling, excluding depreciation expense in our Consolidated Statements of Operations to offset the impact of foreign currency fluctuations in our expenditures in local foreign currencies in the countries in which we operate. See Note 12.

Adjustments to record the carrying value of the ineffective portion of our derivative financial instruments to fair value and realized gains or losses upon settlement of derivative contracts not designated as cash flow hedges are reported as Foreign currency transaction gain (loss) in our Consolidated Statements of Operations. See Notes 6 and 7.

Drilling and Other Property and Equipment

We carry our drilling and other property and equipment at cost. Maintenance and routine repairs are charged to income currently while replacements and betterments, which upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset, are capitalized. Significant judgments, assumptions and estimates may be required in determining whether or not such replacements and betterments meet the criteria for capitalization and in determining useful lives and salvage values of such assets. Changes in these judgments, assumptions and estimates could produce results that differ from those reported. Historically, the amount of capital additions requiring significant judgments, assumptions or estimates has not been significant. During the three months ended March 31, 2015 and the year ended December 31, 2014, we capitalized $95.8 million and $546.0 million, respectively, in replacements and betterments of our drilling fleet, resulting from numerous projects ranging from $25,000 to $215 million per project.

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

Impairment of Long-Lived Assets

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

dayrate by rig;

utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);

the per day operating cost for each rig if active, warm stacked or cold stacked;

the estimated annual cost for rig replacements and/or enhancement programs;

the estimated maintenance, inspection or other 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.

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

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig s age, rated water depth and other attributes and then assesses its future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance and inspection costs, are estimated using historical data adjusted for known developments 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 qualifying construction and upgrade projects. See Note 8. A reconciliation of our total interest cost to Interest expense, net of amounts capitalized as reported in our Consolidated Statements of Operations is as follows:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Total interest cost, including amortization of debt issuance costs	$ 29,996	$ 34,367
Capitalized interest	(6,014)	(16,212)
Total interest expense as reported	$ 23,982	$ 18,155

Foreign Currency

Our functional currency is the U.S. dollar. Foreign currency transaction gains and losses are reported as Foreign currency transaction gain (loss) in our Consolidated Statements of Operations and include, when applicable, unrealized gains and losses to record the carrying value of our FOREX contracts not designated as accounting hedges, as well as realized gains and losses from the settlement of such contracts. For the three-month periods ended March 31, 2015 and 2014, we recognized net foreign currency transaction gains (losses) of $5.6 million and $(1.2) million, respectively. See Note 6.

Revenue Recognition

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

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

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

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

Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2015-03, *Interest Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*, or ASU 2015-03. The purpose of the new standard is to simplify the presentation of debt issuance costs, requiring that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The new standard does not affect the recognition and measurement guidance for debt issuance costs. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015 and interim periods within those fiscal years; however, earlier adoption of the standard is permitted. The new guidance should be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying ASU 2015-03. We are currently evaluating the presentation and disclosure requirements of ASU 2015-03 and expect to adopt its provisions in the first quarter of 2016.

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 also provides for additional disclosure requirements. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and may be adopted using a retrospective or modified retrospective approach. Early adoption is not permitted. We are currently evaluating the provisions of ASU 2014-09 and have not yet determined its impact on our financial position, results of operations or cash flows.

2. Asset Impairments

In response to the continued deterioration of the market fundamentals in the oil and gas industry, including the dramatic decline in oil prices, significant cutbacks in customer capital spending plans and contract cancelations by customers, and increased regulatory requirements we evaluated all of our mid-water semisubmersible rigs, as well as one drillship, for impairment during the first quarter of 2015. Using the undiscounted projected probability weighted cash flow analysis described in Note 1, we determined that the carrying values of seven of our 12 mid-water

semisubmersibles, as well as our older, 7,875-foot water depth rated drillship, which we refer to collectively as the Impaired Rigs, were impaired. Of the Impaired Rigs, five rigs are currently cold stacked, including three semisubmersible rigs that we expect to retire and scrap. The remaining three Impaired Rigs are currently under contract and are expected to be cold stacked or scrapped at the end of their respective contracts.

We determined the fair value of the five cold-stacked rigs using a market approach, which utilized the most recent contracted sales price for another of our previously impaired mid-water semisubmersible rigs, which we expect to scrap in the second quarter of 2015. We determined the fair value of our three rigs currently under

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contract using an income approach, which utilized significant unobservable inputs, including assumptions related to estimated dayrate revenue, rig utilization and anticipated costs for the remainder of the current contract, as well as estimated proceeds that may be received on disposition of each rig. We consider each of these methodologies to be Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used. The actual amount realized upon disposition of the Impaired Rigs may vary if, or when, such rigs are sold.

As a result of our valuations, we recognized an impairment loss aggregating $358.5 million for the three-month period ended March 31, 2015. The aggregate fair value of the Impaired Rigs was $13.7 million at March 31, 2015 and is reported in Drilling and other property and equipment, net of accumulated depreciation in our Consolidated Balance Sheets. We did not record any impairment for the three-month period ended March 31, 2014. See Note 7.

Management s assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation. The use of different assumptions could produce results that differ from those reported.

3. Supplemental Financial Information

Consolidated Balance Sheets Information

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

	March 31, 2015	December 31, 2014
	(In thousands)	
Trade receivables	$ 410,881	$ 437,017
Value added tax receivables	22,774	24,853
Amounts held in escrow	16,664	6,450
Related party receivables	259	339
Other	831	927
	451,409	469,586
Allowance for bad debts	(5,724)	(5,724)
Total	$ 445,685	$ 463,862

Prepaid expenses and other current assets consist of the following:

	March 31, 2015	December 31, 2014
	(In thousands)	
Rig spare parts and supplies	$ 47,215	$ 56,315
Deferred mobilization costs	87,636	53,206
Prepaid insurance	6,037	12,163
Deferred tax assets	15,612	15,612

Prepaid taxes	37,290	44,085
Other	5,531	4,160
Total	$ 199,321	$ 185,541

Accrued liabilities consist of the following:

	March 31, 2015	December 31, 2014
	(In thousands)	
Rig operating expenses	$ 84,368	$ 85,897
Payroll and benefits	126,277	131,664
Deferred revenue	70,973	63,209
Accrued capital project/upgrade costs	34,439	103,123
Interest payable	47,177	18,365
Personal injury and other claims	8,758	8,570
FOREX contracts	2,707	5,439
Other	8,826	10,325
Total	$ 383,525	$ 426,592

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Consolidated Statements of Cash Flows Information

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 34,439	$ 85,266
Restricted stock units vested [1]	880	
Common stock withheld for payroll tax obligations [2]	236	
Cash interest payments[3]		12,531
Cash income taxes paid, net of refunds:		
U.S. federal	(3,344)	
Foreign	21,281	24,416
State		(31)

(1) Represents the cost of 18,617 shares of common stock issued as a result of the vesting of restricted stock units in the first quarter of 2015. An accrual for this share-based liability was presented in Accrued liabilities in our Consolidated Balance Sheets at December 31, 2014.

(2) Represents the cost of 7,810 shares of common stock withheld to satisfy the payroll tax obligation incurred as a result of the vesting of restricted stock units in the first quarter of 2015. This cost is presented as a deduction from stockholders equity in Treasury stock in our Consolidated Balance Sheets at March 31, 2015.

(3) Interest payments, net of amounts capitalized, were $8.1 million for the three months ended March 31, 2014.

4. Earnings Per Share

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands, except per share data)	
Net (loss) income basic and diluted numerator	$ (255,709)	$ 145,810
Weighted average shares basic (denominator):	137,151	138,469
Dilutive effect of stock-based awards		4
Weighted average shares including conversions diluted (denominator)	137,151	138,473

(Loss) earnings per share:				
Basic	$	(1.86)	$	1.05
Diluted	$	(1.86)	$	1.05

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Employee and director:		
Stock options	35	49
Stock appreciation rights	1,624	1,461
Restricted stock units	50	

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5. Marketable Securities

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

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

	March 31, 2015		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
Corporate bonds	$ 16,120	$ (2,226)	$ 13,894
Mortgage-backed securities	118	4	122
Total	$ 16,238	$ (2,222)	$ 14,016

	December 31, 2014		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
Corporate bonds	$ 16,003	$ (104)	$ 15,899
Mortgage-backed securities	130	4	134
Total	$ 16,133	$ (100)	$ 16,033

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Proceeds from maturities	$	$ 2,175,000
Proceeds from sales	11	21
Gross realized gains		
Gross realized losses		

6. Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

Our international operations expose us to foreign exchange risk associated with our costs payable in foreign currencies for employee compensation, foreign income tax payments and purchases from foreign suppliers. We may utilize FOREX contracts to manage our foreign exchange risk. Our FOREX contracts generally require us to net settle the spread between the contracted foreign currency exchange rate and the spot rate on the contract settlement date, which, for most of our contracts, is the average spot rate for the contract period.

We enter into FOREX contracts when we believe market conditions are favorable to purchase contracts for future settlement with the expectation that such contracts, when settled, will reduce our exposure to foreign currency gains and losses on future foreign currency expenditures. The amount and duration of such contracts are based on our monthly forecast of expenditures in the significant currencies in which we do business and for which there is a financial market (*i.e.*, Australian dollars, Brazilian reais, British pounds sterling, and Mexican pesos). These forward contracts are derivatives as defined by GAAP.

During the three months ended March 31, 2015 and 2014, we settled FOREX contracts with aggregate notional values of approximately $57.5 million and $64.6 million, respectively, of which the entire aggregate amounts were designated as a cash flow accounting hedge.

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The following table presents the aggregate amount of gain or loss recognized in our Consolidated Statements of Operations related to our FOREX contracts designated as accounting hedges for the three-month periods ended March 31, 2015 and 2014.

Location of Gain (Loss) Recognized in Income	Three Months Ended March 31, 2015	2014
	(In thousands)	
Contract drilling expense	$ (6,390)	$ 511

As of March 31, 2015, we had FOREX contracts outstanding in the aggregate notional amount of $34.0 million, consisting of $4.4 million in Brazilian reais, $23.7 million in British pounds sterling and $5.9 million in Mexican pesos. These contracts generally settle monthly through September 2015. As of March 31, 2015, all outstanding derivative contracts had been designated as cash flow hedges. See Note 7.

We have International Swap Dealers Association, or ISDA, contracts, which are standardized master legal arrangements that establish key terms and conditions, which govern certain derivative transactions. At March 31, 2015, all of our FOREX contracts were with two counterparties and were governed under such ISDA contracts. There are no requirements to post collateral under these contracts; however, they do contain credit-risk related contingent provisions including credit support provisions and the net settlement of amounts owed in the event of early terminations. Additionally, should our credit rating fall below a specified rating immediately following the merger of Diamond Offshore with another entity, the counterparty may require all outstanding derivatives under the ISDA contract to be settled immediately at current market value. Our ISDA arrangements also include master netting agreements to further manage counterparty credit risk associated with our FOREX contracts. We have elected not to offset the fair value amounts recorded for our FOREX contracts under these agreements in our Consolidated Balance Sheets as of March 31, 2015 and December 31, 2014; however, there would have been no significant difference in our Consolidated Balance Sheets if the estimated fair values were presented on a net basis for these periods.

The following table presents the fair values of our derivative FOREX contracts designated as hedging instruments at March 31, 2015 and December 31, 2014.

Balance Sheet

Location	Fair Value March 31, 2015	December 31, 2014	Balance Sheet Location	Fair Value March 31, 2015	December 31, 2014
	(In thousands)			(In thousands)	
Prepaid expenses and other current assets	$	$	Accrued liabilities	$ (2,707)	$ (5,439)

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
FOREX contracts:		
Amount of (loss) gain recognized in AOCGL on derivative (effective portion)	$ (2,810)	$ 4,368
Location of (loss) gain reclassified from AOCGL into income (effective portion)	Contract drilling expense	Contract drilling expense
Amount of (loss) gain reclassified from AOCGL into income (effective portion)	$ (5,520)	$ 269
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction gain (loss)	Foreign currency transaction gain (loss)
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$ (9)	$ (1)
Treasury lock agreements:		
Amount of gain recognized in AOCGL on derivative (effective portion)		
Location of gain reclassified from AOCGL into income (effective portion)	Interest Expense	Interest Expense
Amount of gain reclassified from AOCGL into income (effective portion)	$ 2	$ 2

As of March 31, 2015, the estimated amount of net unrealized gains (losses) associated with our FOREX contracts and treasury lock agreements that will be reclassified to earnings during the next twelve months was $(2.7) million and $8,000, respectively. The net unrealized gains (losses) associated with these derivative financial instruments will be reclassified to contract drilling expense and interest expense, respectively. During the three-month periods ended March 31, 2015 and 2014, we did not reclassify any amounts from AOCGL due to the probability of an underlying forecasted transaction not occurring.

7. Financial Instruments and Fair Value Disclosures

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

Most of our investments in debt securities are securitized corporate bonds whereby our credit risk is mitigated by the collateral. However, we are exposed to market risk due to price volatility associated with interest rate fluctuations.

Concentrations of credit risk with respect to our trade accounts receivable are limited primarily due to the entities comprising our customer base. Since the market for our services is the offshore oil and gas industry, this customer base consists primarily of major and independent oil and gas companies and government-owned oil companies. At March 31, 2015 and December 31, 2014, Petróleo Brasileiro S.A. (a Brazilian multinational energy company that is majority-owned by the Brazilian government), or Petrobras, accounted for $107.5 million and $123.3 million, or 27% and 29%, respectively, of our total consolidated net trade accounts receivable balance.

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

Fair Values

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

Level 1 Quoted prices for identical instruments in active markets. Level 1 assets include short-term investments such as money market funds, U.S. Treasury Bills and Treasury notes. Our Level 1 assets at March 31, 2015 consisted of cash held in money market funds of $157.1 million and time deposits of $20.3 million. Our Level 1 assets at December 31, 2014 consisted of cash held in money market funds of $197.5 million and time deposits of $20.3 million.

Level 2 Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter FOREX contracts. Our residential mortgage-backed securities and corporate bonds were valued using a model-derived valuation technique based on the quoted closing market prices received from a financial institution. Our FOREX contracts are valued based on quoted market prices, which are derived from observable inputs including current spot and forward rates, less the contract rate multiplied by the notional amount. 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 March 31, 2015 consisted of nonrecurring measurements of seven mid-water semisubmersible rigs and our older 7,875-foot water depth rated drillship for which we recorded an impairment loss during the first quarter of 2015. See Notes 1 and 2.

Market conditions could cause an instrument to be reclassified among Levels 1, 2 and 3. Our policy regarding fair value measurements of financial instruments transferred into and out of levels is to reflect the transfers as having occurred at the beginning of the reporting period. There were no transfers between fair value levels during the three-month periods ended March 31, 2015 and 2014.

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 assets measured at fair value on a nonrecurring basis of $358.5 million during the three-month period ended March 31, 2015. We did not record any such impairment charges during the three-month period ended March 31, 2014.

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Assets and liabilities measured at fair value are summarized below:

	March 31, 2015 Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Period Ended
			(In thousands)		
Recurring fair value measurements:					
Assets:					
Short-term investments	$ 177,385	$	$	$ 177,385	
Corporate bonds		13,894		13,894	
Mortgage-backed securities		122		122	
Total assets	$ 177,385	$ 14,016	$	$ 191,401	
Liabilities:					
FOREX contracts	$	$ (2,707)	$	$ (2,707)	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets	$	$	$ 13,681	$ 13,681	$ 358,528

	December 31, 2014 Fair Value Measurements Using			
	Level 1	Level 2	Level 3	Assets at Fair Value
		(In thousands)		
Recurring fair value measurements:				
Assets:				
Short-term investments	$ 217,789	$	$	$ 217,789
Corporate bonds		15,899		15,899
Mortgage-backed securities		134		134
Total assets	$ 217,789	$ 16,033	$	$ 233,822
Liabilities:				
FOREX contracts	$	$ (5,439)	$	$ (5,439)
Nonrecurring fair value measurements:				

Assets:				
Impaired assets [1]	$	$	$ 9,421	$ 9,421

(1) Represents the book value as of December 31, 2014 of four of our mid-water semisubmersible rigs, which were written down to their estimated recoverable amounts in 2014. Three of these rigs were scrapped in the first quarter of 2015 and the sale of the remaining rig, the *Ocean Winner*, is expected to be completed in the second quarter of 2015.

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

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

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

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We consider our senior notes, including current maturities, to be Level 2 liabilities under the GAAP fair value hierarchy and, accordingly, the fair value of our senior notes was derived using a third-party pricing service at March 31, 2015 and December 31, 2014. 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.

	March 31, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
4.875% Senior Notes due 2015	252.6	250.0	255.0	250.0
5.875% Senior Notes due 2019	557.3	499.6	544.9	499.6
3.45% Senior Notes due 2023	240.3	249.1	232.0	249.1
5.70% Senior Notes due 2039	461.7	497.0	478.5	497.0
4.875% Senior Notes due 2043	627.4	748.9	638.9	748.8

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.

8. Drilling and Other Property and Equipment

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

	March 31, 2015	December 31, 2014
	(In thousands)	
Drilling rigs and equipment	$ 10,062,129	$ 10,555,314
Construction work-in-progress	467,193	439,206
Land and buildings	67,041	66,989
Office equipment and other	71,092	70,591
Cost	10,667,455	11,132,100
Less: accumulated depreciation	(4,093,313)	(4,186,147)
Drilling and other property and equipment, net	$ 6,574,142	$ 6,945,953

During the three months ended March 31, 2015, we scrapped three rigs with an aggregate book value of $2.1 million and recognized an aggregate gain of $1.1 million. In addition, during the three-month period ended March 31, 2015, we recognized an impairment loss of $358.5 million. See Note 2.

Construction work-in-progress, including capitalized interest, at March 31, 2015 and December 31, 2014 is summarized as follows:

	March 31, 2015	December 31, 2014
	(In thousands)	
Ultra-deepwater drillship *Ocean BlackLion*	$ 245,500	$ 225,405
Ultra-deepwater semisubmersible *Ocean GreatWhite*	221,693	213,801
Total construction work-in-progress	$ 467,193	$ 439,206

9. 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.

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Asbestos Litigation. We are one of several unrelated defendants in lawsuits filed in Mississippi and 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 offshore 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 and we expect to receive complete defense and indemnity from Murphy Exploration & Production Company with respect to many of the lawsuits pursuant to the terms of our 1992 asset purchase agreement with them. We also believe that we are not liable for the damages asserted in the remaining lawsuits pursuant to the terms of our 1989 asset purchase agreement with Diamond M Corporation, and we filed a declaratory judgment action in Texas state court against NuStar Energy LP, or NuStar, and Kaneb Management Co., L.L.C., or Kaneb, the successors to Diamond M Corporation, seeking a judicial determination that we did not assume liability for these claims. Trial of this declaratory judgment action is scheduled to commence in 2015. 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.

We have been named in various other lawsuits or threatened actions that are incidental to the ordinary course of our business. We intend to defend these matters vigorously; however, litigation is inherently unpredictable, and the ultimate outcome or effect of these lawsuits and actions cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of these lawsuits. Any claims against us, whether meritorious or not, could cause us to incur costs and expenses, require significant amounts of management time and result in the diversion of significant operational resources. In the opinion of our management, no pending or known threatened claims, actions or proceedings against us are expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Brazilian Withholding Contingency. In July 2014, Petrobras notified us, along with other industry participants, that it is challenging assessments by Brazilian tax authorities of withholding taxes associated with the provision of drilling rigs for its operations in Brazil during the years 2008 and 2009. Petrobras has also notified us that, if Petrobras is ultimately assessed and must pay such withholding taxes, it will seek reimbursement from us for the portion allocable to our drilling rigs. We dispute any basis for Petrobras to obtain such reimbursement, and we have notified Petrobras of our position. If necessary, we intend to defend any reimbursement claims against us vigorously. We are currently unable to estimate the range of loss, if any, that we would incur if Petrobras is ultimately assessed such taxes and if it is determined that Petrobras is entitled to obtain reimbursement from us. If Petrobras is assessed such taxes and we are ultimately required to pay such reimbursement, the amount of such reimbursement could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows.

NPI Arrangement. We received customer payments measured by a percentage net profits interest (primarily of 27%) under an overriding royalty interest in certain developmental oil-and-gas producing properties, or NPI, which we believe is a real property interest. Our drilling program related to the NPI was completed in 2011, and the balance of the amounts due to us under the NPI was received in 2013. However, the customer that conveyed the NPI to us filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in August 2012. Certain parties (including the debtor) in the bankruptcy proceedings questioned whether our NPI, and certain amounts we received under it since the filing of the bankruptcy, should be included in the debtor s estate under the bankruptcy proceeding. In 2013, we filed a declaratory judgment action in the bankruptcy court seeking a declaration that our NPI, and payments that we received from it since the filing of the bankruptcy, are not part of the bankruptcy estate. We agreed to a settlement with the company that purchased most of the debtor s assets (including the debtor s claims against our NPI) whereby the nature of our NPI will not be challenged by that party and our declaratory judgment action was dismissed. Following the settlement, the bankruptcy was converted to a Chapter 7 liquidation proceeding.

Several lienholders who had previously intervened in the declaratory judgment action filed motions in the bankruptcy contending that their liens have priority and seeking disgorgement of payments made to us after the bankruptcy was filed. We believe that our rights to the payments at issue are superior to these liens, and we have filed appropriate motions to dismiss these claims. In addition, the bankruptcy trustee recently filed counterclaims seeking disgorgement of pre- and post-bankruptcy payments made to us under the original NPI. We have filed motions to dismiss these counterclaims and still expect the bankruptcy proceedings to be concluded with no further material impact to us.

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Personal Injury Claims. Under our current insurance policies that expire on May 1, 2016, our deductibles for marine liability insurance coverage, including personal injury claims, which primarily result from Jones Act liability in the Gulf of Mexico, are $25.0 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.

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 March 31, 2015 our estimated liability for personal injury claims was $39.8 million, of which $8.4 million and $31.4 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Consolidated Balance Sheets. At December 31, 2014, our estimated liability for personal injury claims was $39.4 million, of which $8.2 million and $31.2 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Consolidated Balance Sheets. The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

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

Purchase Obligations

Ultra-Deepwater Floater Construction. The *Ocean GreatWhite*, a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig, is under construction in South Korea at an estimated cost of $764 million, including shipyard costs, capital spares, commissioning, project management and shipyard supervision. The contracted price to Hyundai Heavy Industries Co., Ltd., or Hyundai, totaling $628.5 million is payable in two installments, of which the first installment of $188.6 million has been paid. The final installment of $439.9 million is due upon delivery of the rig, which is expected to occur in the first quarter of 2016.

Drillship Construction. We expect to take delivery of the *Ocean BlackLion* in the second quarter of 2015 and will pay the final installment due to Hyundai of approximately $395.0 million at that time.

At March 31, 2015, we had no other purchase obligations for major rig upgrades or any other significant obligations, except for those related to our direct rig operations, which arise during the normal course of business.

Letters of Credit and Other. We were contingently liable as of March 31, 2015 in the amount of $87.3 million under certain performance, security, supersedeas and customs bonds and letters of credit. Agreements relating to approximately $80.7 million of performance, security, supersedeas and customs bonds can require collateral at any time. As of March 31, 2015, 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.

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10. Accumulated Other Comprehensive Gain (Loss)

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

	Unrealized (Loss) Gain on Derivative Financial Instruments	Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2015	$ (3,504)	$ (101)	$ (3,605)
Change in other comprehensive (loss) gain before reclassifications, after tax of $983 and $(1)	(1,827)	(2,123)	(3,950)
Reclassification adjustments for items included in Net Income, after tax of $(1,931) and $0	3,587		3,587
Balance at March 31, 2015	$ (1,744)	$ (2,224)	$ (3,968)

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

Major Category of AOCGL	Three Months Ended March 31, 2015	2014	Consolidated Statements of Operations Line Items
	(In thousands)		
Derivative Financial Instruments:			
Unrealized loss (gain) on FOREX contracts	$ 5,520	$ (269)	Contract drilling, excluding depreciation
Unrealized (gain) loss on Treasury Lock Agreements	(2)	(2)	Interest expense
	(1,931)	94	Income tax expense
	$ 3,587	$ (177)	Net of tax
Marketable Securities:			
Unrealized (gain) loss on marketable securities	$	$ (9)	Other, net
		1	Income tax expense
	$	$ (8)	Net of tax

11. Restructuring and Separation Costs

In response to the continued decline in the offshore drilling market, we reviewed our cost and organization structure, and, as a result, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, otherwise referred to as the Corporate Reduction Plan, in the first quarter of 2015. As of March 31, 2015, appropriate communications have been made to substantially all impacted personnel, and we have recognized $6.2 million in restructuring and employee separation related costs, which we recorded in Accrued liabilities in our Consolidated Balance Sheets. We expect to make approved severance and other related payments under the Corporate Reduction Plan in the second quarter of 2015.

12. 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.

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Floaters:		
Ultra-Deepwater	$ 251,396	$ 205,794
Deepwater	138,770	146,559
Mid-Water	176,357	285,979
Total Floaters	566,523	638,332
Jack-ups	33,054	46,976
Total contract drilling revenues	599,577	685,308
Revenues related to reimbursable expenses	20,479	24,116
Total revenues	$ 620,056	$ 709,424

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 March 31, 2015, our actively-marketed drilling rigs were en route to or located offshore eight 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 March 31,	
	2015	2014
	(In thousands)	
United States	$ 77,158	$ 114,868
International:		
South America	193,075	287,925
Europe/Africa/Mediterranean	151,270	155,591
Australia/Asia	137,135	95,764
Mexico	61,418	55,276
Total revenues	$ 620,056	$ 709,424

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

The following discussion should be read in conjunction with our unaudited consolidated financial statements (including the notes thereto) included elsewhere in this report and our audited consolidated financial statements and the notes thereto, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 1A, Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2014. References to Diamond Offshore, we, us or our mean Diamond Offshore Drilling, Inc., a Delaware corporation, and its subsidiaries.

We are a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a fleet of 35 offshore drilling rigs, excluding three rigs that we plan to retire and scrap. Due to further deterioration in the market for offshore drilling rigs, we have initiated a plan to scrap three of our mid-water semisubmersible rigs, the *Ocean Saratoga*, *Ocean Worker* and *Ocean Yorktown*, all of which are currently cold stacked. Our results for the first quarter of 2015 include a $358.5 million impairment charge related to the three retired rigs, two cold-stacked mid-water semisubmersibles, the *Ocean General* and *Ocean Nomad*, and three additional rigs, the mid-water semisubmersibles *Ocean Ambassador* and *Ocean Lexington*, and the drillship *Ocean Clipper*, which we plan to cold stack or scrap after completion of their current contract terms. See Results of Operations Overview Three Months Ended March 31, 2015 and 2014 *Impairment of Assets*.

Our current fleet consists of 24 semisubmersibles, one of which is under construction, five dynamically-positioned drillships, one of which is under construction, and six jack-ups. Of our current fleet, one deepwater and four mid-water semisubmersible rigs and two jack-up rigs are cold stacked.

We expect to take delivery of our fourth ultra-deepwater drillship, the *Ocean BlackLion*, in the second quarter of 2015. The drillship is then expected to mobilize to the Canary Islands to prepare for the commencement of its engagement in the U.S. Gulf of Mexico, or GOM, later this year. We expect our harsh environment, ultra-deepwater semisubmersible, the *Ocean GreatWhite*, to be delivered in the first quarter of 2016. As of the date of this report, the service-life extension project for the *Ocean Confidence* continues, and the rig should be available for drilling service in the near future.

Market Overview

Current oil prices are well below the high levels reached in the summer of 2014 and remain volatile and unpredictable. As market fundamentals in the oil and gas industry remain depressed, independent and national oil companies, as well as exploration and production companies, have continued to scale back their already reduced 2015 capital spending plans. Thus far in 2015, rig tenders have been infrequent and the few that have occurred have generally been for short-term or well-to-well work. Competition for a limited number of drilling jobs continues to be intense, with numerous offshore drillers vying for the same opportunities, including some contractors bidding multiple rigs on the same bid, and in some cases bidding rigs of both high and lower specifications on the same bid. Operators are continuing to attempt to sublet previously contracted rigs for which capital spending programs have been delayed or canceled. In addition, newbuild floaters continue to enter the market, many of which are not contracted, adding to the oversupply of rigs. With the shortage of work and an oversupply of rigs available for work, price competition remains intense, and some industry analysts are predicting further weakening in dayrates across the floater markets.

In addition, as a result of the depressed market conditions and continued pessimistic outlook for the near term, certain of our customers, as well as those of our competitors, have attempted to renegotiate or terminate existing drilling contracts. Such renegotiations could include requests to lower the contract dayrate, lowering of a dayrate in exchange for additional contract term, shortening the term on one contracted rig in exchange for additional term on another rig,

early termination of a contract in exchange for a lump sum margin 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 or permit the customer to terminate the contract early in the event of excessive downtime, sometimes resulting in no payment to us or sometimes resulting in a contractually specified termination amount, which often does not fully compensate us for the loss of the contract. During depressed market conditions, certain customers may be motivated to utilize 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. 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 adversely impacted. See Contract Drilling Backlog below.

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As previously disclosed, on February 20, 2015, a representative of PEMEX Exploración y Producción, or PEMEX, verbally informed us of PEMEX s intention to exercise its contractual right to terminate its drilling contracts on the *Ocean Ambassador*, the *Ocean Nugget* and the *Ocean Summit,* and to cancel its drilling contract on the *Ocean Lexington*, which contract is currently scheduled to commence in September 2015. As of the date of this report, we have not received written notice of termination or cancellation and we continue to engage in discussions with PEMEX regarding the rigs.

In addition, as previously disclosed, Petróleo Brasileiro S.A., or Petrobras, notified us in the first quarter of 2015 that it has a right to terminate the drilling contract on the *Ocean Baroness* and has verbally informed us that it does not intend to continue to use the rig. To date we have not received written notification of termination from Petrobras.

Current depressed market conditions in the offshore drilling industry have materially impacted our results of operations and cash flows in the first quarter of 2015. We currently expect that these adverse market conditions will continue for the foreseeable future. The continuation of these conditions could result in more of our rigs being without contracts and/or cold stacked or scrapped and could further materially and adversely affect our financial condition, results of operations and cash flows. When we cold stack a rig, we evaluate the rig for impairment. See Results of Operations Overview Three Months Ended March 31, 2015 and 2014 *Impairment of Assets*.

As of April 20, 2015, eight of our rigs were not subject to a drilling contract with a customer, including seven rigs that have been cold stacked or are in the process of being cold stacked. See Contract Drilling Backlog for future commitments of our rigs during 2015 through 2020.

Although these general market conditions impact all segments of the offshore drilling market, the following discussion addresses market conditions within segments of the floater market.

Floater Markets

Ultra-Deepwater and Deepwater Floaters. Globally, the ultra-deepwater and deepwater floater markets continue to be depressed. The continuing oversupply of rigs, combined with diminished demand, has resulted in further decline in dayrates and the stacking, and in some cases scrapping, of rigs in all asset classes. Industry analysts expect offshore drillers to continue to scrap older, lower specification rigs.

Newbuild rig deliveries and established rigs coming off contract continue to fuel an oversupply of floaters in both the ultra-deepwater and deepwater markets. As of the date of this report, based on industry data, there are approximately 53 competitive, or non-owner-operated, newbuild floaters on order. Based on industry reports, nine of the 20 newbuilds scheduled for delivery in 2015, as well as 15 of the 20 newbuilds scheduled for delivery in 2016, are not contracted for future work. Eleven of the 12 newbuilds scheduled for delivery in 2017, as well as the one newbuild on order for delivery in 2018, are also not contracted. In addition, industry reports indicate that Petrobras, our largest single customer based on 2014 annual consolidated revenues, currently has 17 rigs under construction, with two scheduled for delivery in 2015. Industry reports also indicate that only 13 to 17 of the estimated 29 originally planned Petrobras rigs will ultimately be built. The influx of newbuilds into the market, combined with established rigs coming off contract during 2015, is expected to contribute to further weakening of the ultra-deepwater and deepwater floater markets.

Mid-Water Floaters. Conditions in the mid-water market have varied by region, but have generally been adversely impacted by lower demand, the waterfall effect of declining dayrates in the ultra-deepwater and deepwater markets, the challenges experienced by lower specification units in this segment as a result of growing regulatory demands and more complex customer specifications, and the intensified competition resulting from the migration of some

deepwater and ultra-deepwater units to compete against mid-water units. As higher specification rigs take the place of lower specification units, lower specification rigs may continue to be cold stacked or ultimately scrapped.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of April 20, 2015, February 9, 2015 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2014), and April 23, 2014 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014). Contract drilling backlog as presented below includes only firm commitments (typically represented by signed contracts, except as indicated in the footnotes to the tables below), and is calculated by multiplying the contracted operating dayrate by the firm contract period and adding one-half of any potential rig performance bonuses. Our calculation also assumes full utilization of our drilling equipment for the contract period (excluding scheduled shipyard and survey days);

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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.

	April 20, 2015	February 9, 2015	April 23, 2014
		(In thousands)	
Contract Drilling Backlog			
Floaters:			
Ultra-Deepwater [1] [2]	$ 5,167,000	$ 5,390,000	$ 3,910,000
Deepwater [3]	617,000	748,000	962,000
Mid-Water [4]	438,000	611,000	1,504,000
Total Floaters	6,222,000	6,749,000	6,376,000
Jack-ups [5]	49,000	91,000	158,000
Total	$ 6,271,000	$ 6,840,000	$ 6,534,000

[1] Contract drilling backlog as of April 20, 2015 for our ultra-deepwater floaters includes (i) $1.2 billion attributable to our contracted operations offshore Brazil for the years 2015 to 2018; (ii) $584.0 million for the years 2015 to 2019 attributable to future work for the *Ocean BlackLion*, which is under construction; and (iii) $641.0 million for the years 2016 to 2019 attributable to future work for the semisubmersible *Ocean GreatWhite*, which is under construction.

[2] Contract drilling backlog as of April 20, 2015 for our ultra-deepwater floaters excludes $383.5 million attributable to the *Ocean Baroness* contracted to Petrobras. See discussion under Market Overview above.

[3] Contract drilling backlog as of April 20, 2015 for our deepwater floaters includes $163.0 million attributable to our contracted operations offshore Brazil for the years 2015 to 2016.

[4] Contract drilling backlog as of April 20, 2015 for our mid-water floaters excludes $208.8 million attributable to the *Ocean Ambassador* and the *Ocean Lexington*. See discussion under Market Overview above.

[5] Contract drilling backlog as of April 20, 2015 for our jack-ups excludes $49.0 million attributable to the *Ocean Nugget* and the *Ocean Summit*. See discussion under Market Overview above.

The following table reflects the amount of our contract drilling backlog by year as of April 20, 2015.

	Total	For the Years Ending December 31, 2015 [1]	2016	2017	2018	2020
			(In thousands)			
Contract Drilling Backlog						

Floaters:					
Ultra-Deepwater [2] [3]	$ 5,167,000	$ 1,173,000	$ 1,106,000	$ 1,199,000	$ 1,689,000
Deepwater [4]	617,000	361,000	208,000	48,000	
Mid-Water [5]	438,000	171,000	147,000	120,000	
Total Floaters	6,222,000	1,705,000	1,461,000	1,367,000	1,689,000
Jack-ups [6]	49,000	41,000	8,000		
Total	$ 6,271,000	$ 1,746,000	$ 1,469,000	$ 1,367,000	$ 1,689,000

(1) Represents the nine-month period beginning April 1, 2015.

(2) Contract drilling backlog as of April 20, 2015 for our ultra-deepwater floaters includes (i) $348.0 million, $333.0 million, $332.0 million and $158.0 million for the years 2015, 2016, 2017 and 2018, respectively, attributable to our contracted operations offshore Brazil; (ii) $12.0 million, $146.0

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million and $146.0 million for the years 2015, 2016 and 2017, respectively, and $280.0 million in the aggregate for the years 2018 to 2019 attributable to future work for the *Ocean BlackLion*, which is under construction; and (iii) $90.0 million for the year 2016, $214.0 million for the year 2017 and $337.0 million in the aggregate for the years 2018 to 2019 attributable to future work for the *Ocean GreatWhite*, which is under construction.

(3) Contract drilling backlog as of April 20, 2015 for our ultra-deepwater floaters excludes $51.8 million, $113.5 million, $113.1 million and $105.1 million for the years 2015, 2016, 2017 and 2018, respectively, attributable to the *Ocean Baroness* contracted to Petrobras. See discussion under Market Overview above.

(4) Contract drilling backlog as of April 20, 2015 for our deepwater floaters includes $101.0 million and $62.0 million for the years 2015 and 2016, respectively, attributable to our contracted operations offshore Brazil.

(5) Contract drilling backlog as of April 20, 2015 for our mid-water floaters excludes $69.6 million, $66.6 million, $58.4 million and $14.2 million for the years 2015, 2016, 2017 and 2018, respectively, attributable to the *Ocean Ambassador* and the *Ocean Lexington*. See discussion under Market Overview above.

(6) Contract drilling backlog as of April 20, 2015 for our jack-ups excludes $26.9 million and $22.1 million for the years 2015 and 2016, respectively, attributable to the *Ocean Nugget* and the *Ocean Summit*. See discussion under Market Overview above.

The following table reflects the percentage of rig days committed by year as of April 20, 2015. The percentage of rig days committed is calculated as the ratio of total days committed under contracts, as well as scheduled shipyard, survey and mobilization days for all rigs in our fleet, to total available days (number of rigs multiplied by the number of days in a particular year). Total available days have been calculated based on the expected final commissioning dates for the *Ocean BlackLion* and *Ocean GreatWhite*, which are both under construction.

	For the Years Ending December 31,			
	2015 (1)	2016	2017	2018 - 2020
Rig Days Committed (2)(3)				
Floaters:				
Ultra-Deepwater	89%	59%	54%	25%
Deepwater	56%	21%	5%	
Mid-Water	22%	10%	8%	
All Floaters	57%	33%	27%	11%
Jack-ups	24%	3%		

(1) Represents a nine-month period beginning April 1, 2015.

(2) As of April 20, 2015, includes approximately 575 and 294 currently known, scheduled shipyard days for rig commissioning, contract preparation, surveys and extended maintenance projects, as well as rig mobilization days, for the remainder of 2015 and for the year 2016, respectively.

(3) Excludes previously reported rig days attributable to the *Ocean Baroness* contracted to Petrobras and the *Ocean Ambassador*, the *Ocean Nugget*, the *Ocean Summit* and the *Ocean Lexington* contracted to PEMEX. See discussion under Market Overview above.

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 5-year survey, or special survey, that are due every five years for each of our rigs. Operating revenue decreases because these special surveys are generally performed during scheduled downtime in a shipyard. Operating expenses increase as a result of these special surveys due to the cost to mobilize the rigs to a shipyard, inspection costs incurred and repair and maintenance costs. Repair and maintenance activities

may result from the special survey or may have been previously planned to take place during this mandatory downtime. The number of rigs undergoing a 5-year survey will vary from year to year, as well as from quarter to quarter.

In addition, operating income may be negatively impacted by intermediate surveys, which are performed at interim periods between 5-year surveys. Intermediate surveys are generally less extensive in duration and scope than a 5-year survey. Although an intermediate survey may require some downtime for the drilling rig, it normally does not require shipyard time, except for rigs older than 15 years that are located in the United Kingdom, or U.K., sector of the North Sea.

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During the remainder of 2015, two of our rigs will require 5-year surveys, which we expect to result in approximately 100 days of downtime in the aggregate. We also expect to spend an additional approximately 475 days for intermediate surveys, the mobilization of rigs, contract modifications, acceptance testing and extended maintenance projects, including days associated with acceptance testing for the recently delivered *Ocean BlackHornet* and *Ocean BlackRhino* (approximately 44 days in the aggregate) and mobilization of and acceptance testing for the *Ocean BlackLion* (approximately 214 days), which is not expected to commence drilling operations until the fourth quarter of 2015. 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*.

In April 2015, the Bureau of Safety and Environmental Enforcement (an agency established by the U.S. Department of the Interior that governs the offshore drilling industry on the Outer Continental Shelf) announced proposed rules, expected to be enacted into law following a 60-day comment period, which include more stringent design requirements for well control equipment used in offshore drilling operations. Based on our assessment of the proposed rules, we believe that we will need to incur significant capital cost to comply with the additional design requirements to enable our cold stacked mid-water semisubmersibles to return to work in U. S. waters.

Physical Damage and Marine Liability Insurance. We are self-insured for physical damage to rigs and equipment caused by named windstorms in the GOM. If a named windstorm in the GOM causes significant damage to our rigs or equipment, it could have a material adverse effect on our financial position, results of operations and cash flows. Under our current insurance policies that expire on May 1, 2016, we carry physical damage insurance for certain losses, other than those caused by named windstorms in the GOM, for which our deductible for physical damage is $25.0 million per occurrence. There is no assurance, however, that we will be able to retain or obtain, as the case may be, adequate levels of such coverage for such events at rates and with deductibles that we consider to be reasonable, or that we will continue to retain such coverage in the future or obtain such coverage in any particular jurisdiction. We do not typically retain loss-of-hire insurance policies to cover our rigs.

In addition, under our current insurance policies that expire on May 1, 2016, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, with no exclusions for 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, including for personal injury claims, are $25.0 million for the first occurrence and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

Construction and Capital Upgrade Projects. We capitalize interest cost for the construction and upgrade of qualifying assets in accordance with accounting principles generally accepted in the U.S., or GAAP. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use, and the capitalization period ends when the asset is substantially complete and ready for its intended use. We ceased capitalization of interest on five qualifying projects as a result of their completion in 2014 and continue to capitalize interest for our remaining drillship under construction, the *Ocean BlackLion*, and the ultra-deepwater semisubmersible *Ocean GreatWhite*. Consequently, interest expense reported in our Consolidated Statements of Operations will increase, compared to the prior year, due to the completion of projects. As of the date of this report, we expect to cease capitalization of interest for the *Ocean BlackLion* during the second quarter of 2015.

Impact of Changes in Tax Laws or Their Interpretation. We operate through our various subsidiaries in a number of countries throughout the world. As a result, we are subject to highly complex tax laws, treaties and regulations in the

jurisdictions in which we operate, which may change and are subject to interpretation. Changes in laws, treaties and regulations and the interpretation of such laws, treaties and regulations may put us at risk for future tax assessments and liabilities which could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows.

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Critical Accounting Estimates

Impairment of Long-Lived Assets

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

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

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

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

Our other significant accounting policies are discussed in Note 1 of our notes to unaudited consolidated financial statements included in Item 1 of Part I of this report and 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, 2014. There were no material changes to these policies during the three months ended March 31, 2015.

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Results of Operations

Although we perform contract drilling services with different types of drilling rigs and in many geographic locations, there is a similarity of economic characteristics among all our divisions and locations, including the nature of services provided and the type of customers for our services. We believe that the combination of our drilling rigs into one reportable segment is the appropriate aggregation in accordance with applicable accounting standards on segment reporting. However, for purposes of this discussion and analysis of our results of operations, we provide greater detail with respect to the types of rigs in our fleet to enhance the reader s understanding of our financial condition, changes in financial condition and results of operations.

Key performance indicators by equipment type are listed below.

	Three Months Ended March 31,	
	2015	**2014**
REVENUE EARNING DAYS [1]		
Floaters:		
Ultra-Deepwater	506	513
Deepwater	285	343
Mid-Water	663	1,029
Jack-ups	358	501
UTILIZATION [2]		
Floaters:		
Ultra-Deepwater	51%	66%
Deepwater	45%	64%
Mid-Water	49%	64%
Jack-ups	66%	79%
AVERAGE DAILY REVENUE [3]		
Floaters:		
Ultra-Deepwater	$ 496,800	$ 401,200
Deepwater	486,500	427,000
Mid-Water	265,900	277,900
Jack-ups	92,400	93,800

(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 March 31, 2015, our cold-stacked rigs included one deepwater semisubmersible, seven mid-water semisubmersibles and two jack-up rigs.

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

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
CONTRACT DRILLING REVENUE		
Floaters:		
Ultra-Deepwater	$ 251,396	$ 205,794
Deepwater	138,770	146,559
Mid-Water	176,357	285,979
Total Floaters	566,523	638,332
Jack-ups	33,054	46,976
Total Contract Drilling Revenue	$ 599,577	$ 685,308
REVENUES RELATED TO REIMBURSABLE EXPENSES	$ 20,479	$ 24,116
CONTRACT DRILLING EXPENSE		
Floaters:		
Ultra-Deepwater	$ 154,539	$ 123,530
Deepwater	63,675	71,949
Mid-Water	99,320	134,046
Total Floaters	317,534	329,525
Jack-ups	21,570	28,029
Other	11,554	12,236
Total Contract Drilling Expense	$ 350,658	$ 369,790
REIMBURSABLE EXPENSES	$ 20,092	$ 23,666
OPERATING (LOSS) INCOME		
Floaters:		
Ultra-Deepwater	$ 96,857	$ 82,264
Deepwater	75,095	74,610
Mid-Water	77,037	151,933
Total Floaters	248,989	308,807
Jack-ups	11,484	18,947
Other	(11,554)	(12,236)
Reimbursable expenses, net	387	450
Depreciation	(137,299)	(107,011)
General and administrative expense	(17,452)	(22,827)
Gain on disposition of assets	611	147
Impairment of assets	(358,528)	

Restructuring and separation costs	(6,168)	
Total Operating (Loss) Income	$ (269,530)	$ 186,277
Other income (expense):		
Interest income	583	408
Interest expense, net of amounts capitalized	(23,982)	(18,155)
Foreign currency transaction gain (loss)	5,590	(1,178)
Other, net	221	327
(Loss) income before income tax benefit (expense)	(287,118)	167,679
Income tax benefit (expense)	31,409	(21,869)
NET (LOSS) INCOME	$ (255,709)	$ 145,810

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The following is a summary as of the date of this report of the most significant transfers of our rigs during 2015 and 2014 between the geographic areas in which we operate:

Rig	Rig Type	Relocation Details	Date
Floaters:			
Ocean Confidence	Ultra-Deepwater	Angola to Cameroon	February 2014
Ocean BlackHawk	Ultra-Deepwater	South Korea to GOM (initial mobilization)	February 2014
Ocean Confidence	Ultra-Deepwater	Cameroon to Canary Islands (life-extension project)	April 2014
Ocean Clipper	Ultra-Deepwater	Brazil to Colombia	June 2014
Ocean Monarch	Ultra-Deepwater	Indonesia to Malaysia (shipyard project)	September 2014
Ocean Clipper	Ultra-Deepwater	Colombia to Brazil	December 2014
Ocean BlackHornet	Ultra-Deepwater	South Korea to GOM (initial mobilization)	December 2014
Ocean BlackRhino	Ultra-Deepwater	South Korea to GOM (initial mobilization)	December 2014
Ocean Onyx	Deepwater	Placed in service (GOM)	January 2014
Ocean Star	Deepwater	Brazil to GOM	September 2014
Ocean Apex	Deepwater	Singapore to Vietnam	December 2014
Ocean Onyx	Deepwater	GOM to Trinidad	March 2015
Ocean Victory	Deepwater	GOM to Trinidad	March 2015
Ocean General	Mid-Water	Vietnam to Indonesia	March 2014
Ocean Quest	Mid-Water	Malaysia to Vietnam	May 2014
Ocean Patriot	Mid-Water	Singapore to U.K.	June 2014
Ocean Vanguard	Mid-Water	Norway to U.K. (cold stacked July 2014)	June 2014
Ocean General	Mid-Water	Indonesia to Malaysia (cold stacked October 2014)	September 2014
Ocean Worker	Mid-Water	Brazil to GOM (cold stacked February 2015)	January 2015
Ocean Yorktown	Mid-Water	Mexico to GOM (cold stacked March 2015)	March 2015
Jack-ups:			
Ocean Titan	Jack-up	Mexico to GOM (cold stacked January 2015)	June 2014

Overview

Three Months Ended March 31, 2015 and 2014

Operating (Loss) Income. Operating results decreased $455.8 million during the first quarter of 2015, compared to the same period of 2014, primarily due to a $358.5 million impairment loss and $6.2 million in restructuring and severance costs recognized in the first quarter of 2015, combined with the effects of lower utilization, primarily for our mid-water semisubmersible fleet. Depreciation expense increased $30.3 million in the first quarter of 2015, compared to the first quarter of 2014, primarily due to a higher depreciable asset base in 2015, which includes the *Ocean Apex* and three newbuild drillships that were placed in service in 2014.

These unfavorable results, which reduced operating income, were partially offset by the favorable impact of a $19.1 million, or 5%, net reduction in contract drilling expense and a $5.4 million reduction in general and administrative expense, primarily due to lower compensation costs, in the first quarter of 2015, compared to the prior year quarter. The decrease in contract drilling expense reflects lower costs for labor and personnel ($26.4 million) partially offset

by higher mobilization costs ($4.0 million) and a net increase in other rig operating costs and overhead costs ($4.5 million).

Contract drilling revenue decreased $85.7 million, or 13%, during the first quarter of 2015, compared to the same quarter of 2014, primarily as a result of an aggregate of 574 fewer revenue earning days for our drilling fleet, including 366 fewer days for our mid-water floaters. The impact of the fleet-wide decline in utilization was partially offset by higher average daily revenue earned by both our ultra-deepwater and deepwater fleets, including the effect of higher amortized mobilization and contract preparation fees, compared to the prior year quarter.

Impairment of Assets. During the first quarter of 2015, we evaluated all of our mid-water semisubmersibles, as well as one drillship, for impairment. Based on this evaluation, we determined that the carrying value of our 7,875-foot water depth rated drillship, the *Ocean Clipper*, and seven of our 12 mid-water floaters, was impaired. We recorded an impairment loss aggregating $358.5 million in the first quarter of 2015. See Critical Accounting Estimates *Asset Impairments* and Notes 1 and 2 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

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Restructuring and Separation Costs. In response to the continued decline in the offshore drilling market, we have reviewed our cost and organization structure. As result, during the first quarter of 2015, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities. During the three months ended March 31, 2015, we recognized $6.2 million in estimated restructuring and employee separation related costs, which we expect to pay to and on behalf of separated employees in the second quarter of 2015.

Interest Expense, Net of Amounts Capitalized. Interest expense increased $5.8 million during the first quarter of 2015, compared to the same period in 2014, primarily as a result of less interest being capitalized in the first quarter of 2015 on our remaining construction projects ($10.2 million). This unfavorable impact was partially offset by the absence of $3.3 million of interest expense recognized in the first quarter of 2014 related to our 5.15% Senior Notes, which we repaid in September 2014, combined with a $0.8 million reduction in interest expense recognized associated with uncertain tax positions.

Income Tax Expense. Our effective tax rate for the three months ended March 31, 2015 was 10.9%, compared to a 13.0% effective tax rate for the three months ended March 31, 2014. The effective tax rate in the 2015 period was lower than in the same period of 2014 primarily due to the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken in various jurisdictions in 2015. The 2014 period also included the settlement of certain disputes in Egypt for the years 2006 through 2008, resulting in an aggregate $17.2 million reduction in tax expense.

Contract Drilling Revenue and Expense by Equipment Type

Three Months Ended March 31, 2015 and 2014

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $45.6 million during the first quarter of 2015, compared to the first quarter of 2014, primarily as a result of higher average daily revenue earned in the first quarter of 2015, compared to the prior year quarter ($48.4 million). Average daily revenue for the first quarter of 2015 increased compared to the first quarter of 2014, primarily due to revenue associated with incremental operations for the *Ocean BlackHawk* in the GOM and the *Ocean Endeavor* in Romania, a contract extension for the *Ocean Rover* at a higher dayrate than previously earned and a dayrate adjustment for the *Ocean Courage*, combined with incremental amortization of $7.6 million in mobilization and contract preparation fees. However, these positive factors were partially offset by a decrease in revenue earned by the *Ocean Confidence* and *Ocean Baroness* due to downtime associated with a service-life extension project and operational issues, respectively, during the first quarter of 2015.

Contract drilling expense for our ultra-deepwater floaters increased $31.0 million during the first quarter of 2015, compared to the first quarter of 2014, reflecting incremental contract drilling expense for the *Ocean BlackHawk* ($19.1 million) and *Ocean Endeavor* ($13.4 million), partially offset by lower operating costs for the *Ocean Confidence* due to its service-life extension project ($9.1 million), which began in the first quarter of 2014. Contract drilling expense for our other ultra-deepwater floaters increased $8.2 million, reflecting higher repair, inspection and freight costs.

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $7.8 million in the first quarter of 2015, compared to the same quarter in 2014, primarily due to 58 fewer revenue earning days ($24.7 million) in the current year quarter, partially offset by higher average daily revenue earned ($17.0 million). The reduction in revenue earning days was the result of incremental downtime for the mobilization of rigs (57 additional days) and unplanned downtime associated with the warm stacking of rigs between contracts (66 additional days), partially offset by 61 revenue earning days for the *Ocean Apex*, which was placed into service in late 2014. The higher average daily revenue earned

during the first quarter of 2015 is reflective of revenue earned by the *Ocean Apex*, including amortization of $5.3 million in mobilization fees.

Contract drilling expense incurred by our deepwater floaters decreased $8.3 million during the first quarter of 2015, compared to the same quarter of 2014, primarily due to reduced operating costs for rigs that were stacked or undergoing shipyard projects during the first quarter of 2015 ($10.0 million), the absence of costs associated with a 2014 five-year survey for the *Ocean Alliance* ($5.4 million), which began in February 2014, and lower labor and personnel-related costs ($2.0 million). These cost reductions were partially offset by incremental operating costs incurred by the *Ocean Apex* ($10.9 million) in the 2015 period.

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Mid-Water Floaters. Revenue generated by our mid-water floaters decreased $109.6 million in the first quarter of 2015, compared to the same quarter in 2014, primarily due to 366 fewer revenue earning days ($101.6 million) and lower average daily revenue earned ($8.0 million). The reduction in revenue earning days during the first quarter of 2015 was the result of incremental downtime associated with cold-stacked and retired rigs (645 additional days), partially offset by 280 incremental revenue earning days, primarily for the *Ocean Patriot*, which resumed operations in the fourth quarter of 2014 after completion of an enhancement project (90 additional days) and the *Ocean Quest,* which operated in Vietnam during the first quarter of 2015, compared to the prior year quarter when the rig was stacked (90 additional days), and fewer incremental downtime days for mobilization, contract preparation activities and unplanned repairs (100 fewer days).

Contract drilling expense decreased $34.7 million in the first quarter of 2015, compared to the prior year quarter, primarily due to reduced operating costs for our stacked mid-water rigs ($47.6 million), partially offset by incremental costs incurred by the *Ocean Patriot* ($12.8 million).

Jack-ups. Contract drilling revenue and expense for our jack-up fleet decreased $13.9 million and $6.5 million, respectively, during the first quarter of 2015, compared to the prior year quarter, primarily due to the cold stacking of the *Ocean Titan* and *Ocean King* in the second half of 2014.

Liquidity and Capital Resources

We currently have available a syndicated Revolving Agreement, or Credit Agreement, to meet our short-term and long-term liquidity needs. During the second quarter of 2015, we expect to issue commercial paper in amounts to be determined to meet our short-term liquidity needs, including the final installment payable upon delivery of our newbuild drillship, the *Ocean BlackLion*. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations Rig Construction and Credit Agreement, Senior Notes and Commercial Paper Program *Credit Agreement*.

At March 31, 2015 and December 31, 2014, we had cash available for current operations as follows:

	March 31, 2015	December 31, 2014
	(In thousands)	
Cash and equivalents	$ 184,775	$ 233,623
Marketable securities	14,016	16,033
Total cash available for current operations	$ 198,791	$ 249,656

As of April 20, 2015, our contract drilling backlog was approximately $6.2 billion, of which approximately $1.7 billion is expected to be realized in the last nine months of 2015.

Historically, a substantial portion of our cash flows has been invested in the enhancement of our drilling fleet. We determine the amount of cash required to meet our capital commitments by evaluating our rig construction obligations, the need to upgrade rigs to meet specific customer requirements and our ongoing rig equipment enhancement/replacement programs.

Certain of our international rigs are owned and operated, directly or indirectly, by our wholly-owned subsidiary Diamond Offshore International Limited, or DOIL, and, as a result of our intention to indefinitely reinvest the earnings of DOIL to finance our foreign activities, we do not expect such earnings to be available for distribution to our stockholders or to finance our domestic activities. To the extent available, we expect to utilize the operating cash flows generated by and cash reserves of DOIL 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. However, in light of the significant cash requirements of our capital expansion program in the remainder of 2015 and in 2016, we may also make use of our credit facility or commercial paper program to finance our capital expenditures and working capital requirements. In addition, we will make periodic assessments of our capital spending programs based on industry conditions and make adjustments thereto if required. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations Rig Construction and Credit Agreement, Senior Notes and Commercial Paper Program.

We pay dividends at the discretion of our Board of Directors, or Board. During the three-month period ended March 31, 2015, we paid cash dividends totaling $17.1 million. During the three-month period ended March 31, 2014, we paid regular and special cash dividends totaling $17.4 million and $105.3 million, respectively. Our Board has adopted a policy of paying regular and special cash dividends, in amounts to be determined, on a quarterly basis. 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

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current and future market conditions and business needs and other factors that our Board considers relevant at that time. Our dividend policy may change from time to time, and there can be no assurance that we will continue to declare any cash dividends at all or in any particular amounts.

On May 1, 2015, we declared a regular cash dividend of $0.125 per share of our common stock, which is payable on June 1, 2015 to stockholders of record on May 15, 2015.

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 three-month period ended March 31, 2015. However, during the three months ended March 31, 2015, in connection with the vesting of restricted stock units held by our chief executive officer, we withheld 7,810 shares of common stock, with a cost of $0.2 million, to satisfy the associated payroll tax obligation.

During the three-month period ended March 31, 2014, we purchased 1,865,311 shares of our common stock at an aggregate cost of $86.4 million. In addition, Loews Corporation, or Loews, has informed us that, depending on market and other conditions, it may, from time to time, purchase shares of our common stock in the open market or otherwise. During the three-month period ended March 31, 2015, Loews purchased 904,154 shares of our common stock. Loews did not purchase any shares of our outstanding common stock during the three-month period ended March 31, 2014.

Our primary source of cash during the three-month period ended March 31, 2015, was an aggregate $160.6 million generated from operating activities and $4.8 million from the disposition of assets. Our primary uses of cash during the same period were $197.0 million towards the construction of new rigs and our ongoing rig equipment enhancement/replacement program, and $17.1 million for the payment of dividends.

For the three-month period ended March 31, 2014, our primary source of cash was an aggregate $303.0 million generated from operating activities and $575.1 million in proceeds, primarily from the maturity of marketable securities, net of purchases. Our primary uses of cash during the same period were $595.3 million towards the construction of new rigs and our ongoing rig equipment enhancement/replacement program, $122.7 million for the payment of dividends and $86.4 million for the repurchase of shares.

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

Cash Flow, Capital Expenditures and Contractual Obligations

Our cash flow from operations and capital expenditures for the three-month periods ended March 31, 2015 and 2014 were as follows:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Cash flow from operations	$ 160,566	$ 303,015

Cash capital expenditures:		
Drillship construction	$ 31,796	$ 426,385
Construction of deepwater floaters	33,774	17,399
Construction of ultra-deepwater floater	7,892	3,715
Ocean Patriot enhancement project	719	13,122
Ocean Confidence service-life extension project	43,078	
Rig equipment and replacement programs	79,773	134,693
Total capital expenditures	$ 197,032	$ 595,314

Cash Flow

Cash flow from operations decreased approximately $142.4 million during the first three months of 2015, compared to the first three months of 2014, primarily due to lower cash receipts from contract drilling services ($129.4 million) and an increase in cash payments for contract drilling expenses, including mobilization and contract preparation costs ($19.5 million), partially offset by lower cash income taxes paid, net of refunds ($6.4 million).

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Capital Expenditures

As of the date of this report, we expect our capital spending for 2015 to aggregate approximately $920.0 million, of which we expect to spend approximately $630.0 million on our current rig construction projects, including the *Ocean Confidence* service-life-extension project. During the first three months of 2015, we incurred $69.2 million in project-related expenditures, including accrued expenditures. See Contractual Cash Obligations Rig Construction. Our 2015 capital spending program also includes an estimated $290.0 million for our ongoing capital maintenance and replacement programs of which $79.8 million had been incurred as of March 31, 2015.

Contractual Cash Obligations Rig Construction

As of the date of this report, we have two rigs under construction in Ulsan, South Korea and are obligated under separate construction agreements with Hyundai Heavy Industries Co., Ltd., or Hyundai, for the construction of these two rigs. See Note 9 Commitments and Contingencies to our unaudited consolidated financial statements included in Item 1 of Part I of this report for further discussion of these projects.

Our fourth new drillship, the *Ocean BlackLion*, is expected to be delivered in mid-May 2015 at which time the final installment of $395.0 million is due. The estimated total project cost, including shipyard costs, capital spares, commissioning, project management and shipyard supervision, is $655.0 million. We have spent $213.4 million project-to-date as of March 31, 2015.

The construction of our new ultra-deepwater floater, the *Ocean GreatWhite*, continues with delivery expected in the first quarter of 2016. The estimated total project cost, including shipyard costs, capital spares, commissioning, project management and shipyard supervision, is $764.0 million, of which $201.8 million has been spent as of March 31, 2015.

We had no other purchase obligations for major rig upgrades or any other significant obligations at March 31, 2015, except for those related to our direct rig operations, which arise during the normal course of business.

Other Obligations

As of March 31, 2015, we had foreign currency forward exchange, or FOREX, contracts outstanding in the aggregate notional amount of $34.0 million. See further information regarding these contracts in Quantitative and Qualitative Disclosures About Market Risk *Foreign Exchange Risk* in Item 3 of Part I of this report and Note 6 Derivative Financial Instruments to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

As of March 31, 2015, the total unrecognized tax benefits related to uncertain tax positions was $52.2 million. In addition, we have recorded a liability, as of March 31, 2015, for potential penalties and interest of $38.8 million and $7.7 million, respectively. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in these balances, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities.

Credit Agreement, Senior Notes and Commercial Paper Program

Credit Agreement

Our Credit Agreement provides for a $1.5 billion senior unsecured revolving credit facility, for general corporate purposes, which matures on October 22, 2019, except for $40 million of commitments that mature on March 17, 2019.

We also have the option to increase the revolving commitments under the Credit Agreement by up to an additional $500 million from time to time, upon receipt of additional commitments from new or existing lenders, and to request up to two additional one-year extensions of the maturity date. The entire amount of the facility is available, subject to its terms, for revolving loans. Up to $250 million of the facility may be used for the issuance of performance or other standby letters of credit and up to $100 million may be used for swingline loans. As of March 31, 2015, there were no loans or letters of credit outstanding under the Credit Agreement.

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Senior Notes

Our 4.875% Senior Notes due July 1, 2015 in the aggregate principal amount of $250.0 million will mature on July 1, 2015.

Commercial Paper Program

In February 2015, we established a commercial paper program with three commercial paper dealers pursuant to which we may issue, on a private placement basis, unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time of $1.5 billion. Proceeds from issuances under the commercial paper program may be used for general corporate purposes. The maturities of the notes may vary, but may not exceed 397 days from the date of issuance. The notes will be issued, at our option, either at a discounted price to their principal face value or will bear interest, which may be at a fixed or floating rate, at rates that will vary based on market conditions and the ratings assigned by credit rating agencies at the time of issuance. The notes are not redeemable or subject to voluntary prepayment by us prior to maturity. Our Credit Agreement provides liquidity for our payment obligations in respect of the notes issued under the commercial paper program, and unless we change the terms of the program, the aggregate amount of notes outstanding at any time will not exceed the amount available under the Credit Agreement. As of March 31, 2015, we had no commercial paper notes outstanding.

Credit Ratings

In April 2015, Standard & Poor s Ratings Services, or S&P, revised its outlook on us from negative to stable and lowered our corporate credit and unsecured debt rating from A- to BBB+. Our current credit rating is A3 for Moody s Investors Services, or Moody s. In February 2015, Moody s and S&P assigned short-term credit ratings of Prime-2 and A2, respectively, to our commercial paper program. Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered. A downgrade in our credit ratings could impact our cost of issuing additional debt and the amount of additional debt that we could issue. A series of downgrades or a substantial downgrade could restrict our access to capital markets and our ability to raise additional debt or rollover existing maturities. 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 March 31, 2015 in the amount of $87.3 million under certain performance, security, supersedeas and customs bonds and letters of credit. Agreements relating to approximately $80.7 million of performance, security, supersedeas and customs bonds can require collateral at any time. As of March 31, 2015, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. Banks have issued letters of credit on our behalf securing certain of these bonds. The table below provides a list of these obligations in U.S. dollar equivalents and their time to expiration.

		For the Years Ending December 31,			
	Total	2015	2016	2017	2018
	(In thousands)				
Other Commercial Commitments					

Performance bonds	$ 76,026	$ 18,449	$ 5,322	$ 33,130	$ 19,125
Supersedeas bond	9,189	9,189			
Other	2,131	1,981	150		
Total obligations	$ 87,346	$ 29,619	$ 5,472	$ 33,130	$ 19,125

Off-Balance Sheet Arrangements

At March 31, 2015 and December 31, 2014, we had no off-balance sheet debt or other off-balance sheet arrangements.

Recent Accounting Pronouncements

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

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Forward-Looking Statements

We or our representatives may, from time to time, either in this report, in periodic press releases or otherwise, make or incorporate by reference certain written or oral statements that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain or be identified by the words expect, intend, plan, predict, anticipate, estimate, believe, should, could, will be, will continue, will likely result, project, forecast, budget and similar expressions. In addition, any stat concerning future financial performance (including, without limitation, future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by or against us, which may be provided by management, are also forward-looking statements 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;

availability under our Credit Agreement and issuance of notes under our commercial paper program;

interest rate and foreign exchange risk;

contractual obligations;

operations outside the United States;

business strategy;

growth opportunities;

competitive position;

expected financial position;

cash flows and contract backlog;

declaration or payment of regular or special dividends;

financing plans;

market outlook;

tax planning;

debt levels, credit ratings 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 rig upgrades, construction projects and other capital projects;

delivery dates and drilling contracts related to rig conversion or upgrade projects, construction projects, other capital projects or rig acquisitions;

plans and objectives of management;

idling drilling rigs or reactivating stacked rigs;

scrapping retired rigs;

assets held for sale;

asset impairments and impairment evaluations and any future use or disposition of impaired assets;

effective date and performance of contracts;

outcomes of legal proceedings;

compliance with applicable laws; and

availability, limits and adequacy of insurance or indemnification.

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

those described under Risk Factors in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2014;

general economic and business conditions;

worldwide demand for oil and natural gas;

changes in foreign and domestic oil and gas exploration, development and production activity;

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oil and natural gas price fluctuations and related market expectations;

the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain production levels and pricing, and the level of production in non-OPEC countries;

policies of various governments regarding exploration and development of oil and gas reserves;

our inability to obtain contracts for our rigs that do not have contracts;

the cancellation or renegotiation of contracts included in our reported contract backlog;

advances in exploration and development technology;

the worldwide political and military environment, including, for example, in oil-producing regions and locations where our rigs are operating or where we have rigs under construction;

casualty losses;

operating hazards inherent in drilling for oil and gas offshore;

the risk that future regular or special dividends may not be declared or paid;

the risk of physical damage to rigs and equipment caused by named windstorms in the GOM;

industry fleet capacity, including, without limitation, construction of new drilling rig capacity in Brazil;

market conditions in the offshore contract drilling industry, including, without limitation, dayrates and utilization levels;

competition;

changes in foreign, political, social and economic conditions;

risks of international operations, compliance with foreign laws and taxation policies and seizure, expropriation, nationalization, deprivation, malicious damage or other loss of possession or use of equipment and assets;

risks of potential contractual liabilities pursuant to our various drilling contracts in effect from time to time;

customer or supplier bankruptcy or liquidation;

the ability of customers and suppliers to meet their obligations to us and our subsidiaries;

collection of receivables;

the risk that a letter of intent may not result in a definitive agreement;

foreign exchange and currency fluctuations and regulations, and the inability to repatriate income or capital;

risks of war, military operations, other armed hostilities, terrorist acts and embargoes;

changes in offshore drilling technology, which could require significant capital expenditures in order to maintain competitiveness;

regulatory initiatives and compliance with governmental regulations including, without limitation, regulations pertaining to climate change, greenhouse gases, carbon emissions or energy use;

compliance with and liability under environmental laws and regulations;

potential changes in accounting policies by the Financial Accounting Standards Board, the Securities and Exchange Commission, or SEC, or regulatory agencies for our industry which may cause us to revise our financial accounting and/or disclosures in the future, and which may change the way analysts measure our business or financial performance;

development and exploitation of alternative fuels;

customer preferences;

effects of litigation, tax audits and contingencies and the impact of compliance with judicial rulings and jury verdicts;

cost, availability, limits and adequacy of insurance;

invalidity of assumptions used in the design of our controls and procedures;

the results of financing efforts;

adequacy and availability of our sources of liquidity;

risks resulting from our indebtedness;

public health threats;

negative publicity;

impairments of assets;

the availability of qualified personnel to operate and service our drilling rigs; and

various other matters, many of which are beyond our control.

The risks and uncertainties included here are not exhaustive. Other sections of this report and our other filings with the SEC include additional factors that could adversely affect our business, results of operations and financial performance. Given these risks and uncertainties, investors should not place undue reliance on forward-looking statements. Forward-looking statements included in this report speak only as of the date of this report. We

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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.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk.

There were no material changes in our market risk components for the three months ended March 31, 2015. See Quantitative and Qualitative Disclosures About Market Risk included in Item 7A of our Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2014 for further information.

ITEM 4. Controls and Procedures.

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

Our Chief Executive Officer, or CEO, and Chief Financial Officer, or CFO, participated in an evaluation by our management of the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of March 31, 2015. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of March 31, 2015.

There were no changes in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during our first fiscal quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

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 March 31, 2015, in connection with the vesting of restricted stock units held by our chief executive officer, 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	Maximum Number of Shares that May Yet Be Purchased

				Plans or Programs	Under the Plans or Programs
January 1, 2015 through January 31, 2015				N/A	N/A
February 1, 2015 through February 28, 2015				N/A	N/A
March 1, 2015 through March 31, 2015	7,810	$	30.33	N/A	N/A
Total	7,810	$	30.33	N/A	N/A

ITEM 6. Exhibits.

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

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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 May 4, 2015

By: \s\ Gary T. Krenek
Gary T. Krenek
Senior Vice President and Chief Financial Officer

Date May 4, 2015

\s\ Beth G. Gordon
Beth G. Gordon
Controller (Chief Accounting Officer)

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EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003) (SEC File No. 1-13926).
3.2	Amended and Restated By-laws (as amended through October 4, 2013) of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 8, 2013).
10.1	Form of Commercial Paper Dealer Agreement between Diamond Offshore Drilling, Inc. and the Dealer party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on February 12, 2015).
10.2	Specimen Agreement for grants of restricted stock units to officers (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on March 30, 2015).
10.3	Specimen Agreement for grants of restricted stock units to the Chief Executive Officer (incorporated by reference to Exhibit 10.2 to our Current Report on 8-K filed March 30, 2015).
10.4*	Amendment to Employment Agreement, dated April 1, 2015, between Diamond Offshore Management Company and Beth G. Gordon.
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.