HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
July 22, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-Q

þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 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 001-32936

HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	95–3409686 (I.R.S. Employer Identification No.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas (Address of principal executive offices)	77043 (Zip Code)

(281) 618–0400
(Registrant's telephone number, including area code)
NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

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. þ Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No

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

Large accelerated filer þ	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 þ No

As of July 17, 2015, 105,959,614 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$500,062	$476,492
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $7,525 and $4,735, respectively	120,659	104,724
Unbilled revenue	39,883	28,542
Costs in excess of billing	3,436	2,034
Current deferred tax assets	32,331	31,180
Other current assets	36,664	51,301
Total current assets	733,035	694,273
Property and equipment	2,474,882	2,241,444
Less accumulated depreciation	(554,909)	(506,060)
Property and equipment, net	1,919,973	1,735,384
Other assets:		
Equity investments	145,588	149,623
Goodwill	62,294	62,146
Other assets, net	73,306	59,272
Total assets	$2,934,196	$2,700,698
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$98,804	$83,403
Accrued liabilities	66,788	104,923
Income tax payable	—	9,143
Current maturities of long-term debt	71,497	28,144
Total current liabilities	237,089	225,613
Long-term debt	722,515	523,228
Deferred tax liabilities	257,852	260,275
Other non-current liabilities	41,414	38,108
Total liabilities	1,258,870	1,047,224
Commitments and contingencies		
Shareholders’ equity:		
Common stock, no par, 240,000 shares authorized, 105,949 and 105,586 shares issued, respectively	939,504	934,447
Retained earnings	798,286	781,279
Accumulated other comprehensive loss	(62,464)	(62,252)
Total shareholders’ equity	1,675,326	1,653,474
Total liabilities and shareholders’ equity	$2,934,196	$2,700,698

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)
(in thousands, except per share amounts)

	Three Months Ended June 30,	
	2015	2014
Net revenues	$166,016	$305,587
Cost of sales	141,808	196,449
Gross profit	24,208	109,138
Loss on disposition of assets	—	(1,078)
Selling, general and administrative expenses	(16,534)	(29,304)
Income from operations	7,674	78,756
Equity in losses of investments	(323)	(507)
Net interest expense	(5,235)	(4,517)
Other expense, net	(5,036)	(17)
Other income – oil and gas	899	1,596
Income (loss) before income taxes	(2,021)	75,311
Income tax provision	614	17,529
Net income (loss) applicable to common shareholders	$(2,635)	$57,782
Earnings (losses) per share of common stock:		
Basic	$(0.03)	$0.55
Diluted	$(0.03)	$0.55
Weighted average common shares outstanding:		
Basic	105,357	104,992
Diluted	105,357	105,295

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)
(in thousands, except per share amounts)

	Six Months Ended June 30, 2015	2014
Net revenues	$355,657	$559,159
Cost of sales	296,502	374,175
Gross profit	59,155	184,984
Gain on disposition of assets, net	—	10,418
Selling, general and administrative expenses	(29,153)	(49,698)
Income from operations	30,002	145,704
Equity in earnings (losses) of investments	(302)	201
Net interest expense	(9,305)	(9,000)
Other expense, net	(6,192)	(827)
Other income – oil and gas	3,825	13,872
Income before income taxes	18,028	149,950
Income tax provision	1,021	37,946
Net income, including noncontrolling interests	17,007	112,004
Less net income applicable to noncontrolling interests	—	(503)
Net income applicable to common shareholders	$17,007	$111,501
Earnings per share of common stock:		
Basic	$0.16	$1.06
Diluted	$0.16	$1.05
Weighted average common shares outstanding:		
Basic	105,324	105,059
Diluted	105,324	105,359

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)
(in thousands)

	Three Months Ended June 30, 2015	2014
Net income (loss) applicable to common shareholders	$(2,635)	$57,782
Other comprehensive income, net of tax:		
Unrealized gain (loss) on hedges arising during the period	3,346	(4,129)
Reclassification adjustments for loss included in net income (loss)	3,258	610
Income taxes on unrealized (gain) loss on hedges	(2,311)	1,232
Unrealized gain (loss) on hedges, net of tax	4,293	(2,287)
Foreign currency translation gain	15,889	6,931
Other comprehensive income, net of tax	20,182	4,644
Comprehensive income applicable to common shareholders	$17,547	$62,426

	Six Months Ended June 30, 2015	2014
Net income, including noncontrolling interests	$17,007	$112,004
Other comprehensive income (loss), net of tax:		
Unrealized loss on hedges arising during the period	(8,365)	(74)
Reclassification adjustments for loss included in net income	4,931	1,268
Income taxes on unrealized (gain) loss on hedges	1,202	(418)
Unrealized gain (loss) on hedges, net of tax	(2,232)	776
Foreign currency translation gain	2,020	8,278
Other comprehensive income (loss), net of tax	(212)	9,054
Comprehensive income	16,795	121,058
Less comprehensive income applicable to noncontrolling interests	—	(503)
Comprehensive income applicable to common shareholders	$16,795	$120,555

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)
(in thousands)

	Six Months Ended June 30, 2015	2014
Cash flows from operating activities:		
Net income, including noncontrolling interests	$17,007	$112,004
Adjustments to reconcile net income, including noncontrolling interests, to net cash provided by operating activities:		
Depreciation and amortization	53,528	52,853
Amortization of deferred financing costs	2,596	2,435
Stock-based compensation expense	3,515	3,755
Amortization of debt discount	2,928	2,765
Deferred income taxes	(2,454)	27,669
Excess tax from stock-based compensation	(86)	(382)
Gain on disposition of assets, net	—	(10,418)
Unrealized loss and ineffectiveness on derivative contracts, net	1,941	69
Changes in operating assets and liabilities:		
Accounts receivable, net	(29,006)	(40,687)
Other current assets	11,904	(1,998)
Income tax payable, net of income tax receivable	(9,472)	(24,376)
Accounts payable and accrued liabilities	(35,318)	14,312
Other noncurrent, net	(14,050)	1,504
Net cash provided by operating activities	3,033	139,505
Cash flows from investing activities:		
Capital expenditures	(232,872)	(93,001)
Distributions from equity investments, net	3,842	4,849
Proceeds from sale of assets	7,500	11,074
Acquisition of noncontrolling interests	—	(20,085)
Net cash used in investing activities	(221,530)	(97,163)
Cash flows from financing activities:		
Proceeds from Nordea Term Loan	250,000	—
Repayment of Term Loan	(7,500)	(7,500)
Repayment of MARAD Debt	(2,788)	(2,655)
Deferred financing costs	(1,533)	—
Distributions to noncontrolling interests	—	(1,018)
Repurchases of common stock	(1,056)	(6,653)
Excess tax from stock-based compensation	86	382
Proceeds from issuance of ESPP shares	2,512	1,932
Net cash provided by (used in) financing activities	239,721	(15,512)
Effect of exchange rate changes on cash and cash equivalents	2,346	(3,573)
Net increase in cash and cash equivalents	23,570	23,257
Cash and cash equivalents:		
Balance, beginning of year	476,492	478,200

Balance, end of period	$500,062	$501,457

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)
Note 1 — Basis of Presentation and New Accounting Standards

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its wholly and majority owned subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its wholly and majority owned subsidiaries. All material intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission (the "SEC"), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("U.S. GAAP") and are consistent in all material respects with those applied in our 2014 Annual Report on Form 10-K ("2014 Form 10-K"). The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. The operating results for the three- and six-month periods ended June 30, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015. Our balance sheet as of December 31, 2014 included herein has been derived from the audited balance sheet as of December 31, 2014 included in our 2014 Form 10-K. These unaudited condensed consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and notes thereto included in our 2014 Form 10-K.

We have made all adjustments (which were normal recurring adjustments) that we believe are necessary for a fair presentation of the condensed consolidated balance sheets, statements of operations, statements of comprehensive income (loss), and statements of cash flows, as applicable. Our operating results for the three- and six-month periods ended June 30, 2015 included an out-of-period adjustment to correct an error related to a well intervention project performed in 2014 in which our revenues included certain income tax withholding payments made on our behalf and which now will have to be refunded to the counterparty. This adjustment affects our 2015 operating results by reducing our net revenues by $2.5 million and increasing our net loss by $1.7 million. The amounts were not deemed material with respect to prior year or the anticipated results and the trend of earnings for fiscal year 2015.

Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

In May 2014, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This ASU provides a single five-step approach to account for revenue arising from contracts with customers. The ASU requires an entity to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This revenue standard was originally effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. In July 2015, the FASB elected to defer its effective date by one year to December 15, 2017. Adoption as of the original effective date is permitted. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption through a cumulative adjustment. We are currently evaluating which transition approach to use and the potential impact the adoption of this standard may have on our consolidated financial statements.

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In April 2015, the FASB issued ASU No. 2015-03, “Simplifying the Presentation of Debt Issuance Costs.” This ASU requires that debt issuance costs related to a recognized debt liability be reported on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The guidance is effective retrospectively beginning in the first quarter of fiscal 2017 and early adoption is permitted. We do not expect this guidance to materially affect our balance sheets as amounts will be reclassified from long-term assets to partial offsets to long-term debt. The guidance will not affect our statements of operations or statements of cash flows.

Note 2 — Company Overview

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We provide services primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and intend to increase our operations offshore Brazil. Our “life of field” services are segregated into three reportable business segments: Well Intervention, Robotics and Production Facilities (Note 11).

Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our Well Intervention segment also includes certain intervention riser systems that are available on a rental basis. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our well intervention fleet also includes the Q5000, a newbuild semi-submersible well intervention vessel that was delivered to us at the end of April 2015 and is currently in transit to the Gulf of Mexico. We are currently constructing another well intervention vessel, the Q7000. We have also contracted to charter two newbuild monohull vessels, which are expected to be delivered in 2016 and used in connection with our contracts to provide well intervention services offshore Brazil.

Our Robotics segment includes remotely operated vehicles (“ROVs”), trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates five chartered ROV and trencher support vessels including the Grand Canyon II, which was delivered to us in late April 2015.

Our Production Facilities segment includes the Helix Producer I vessel (“HP I”) as well as our equity investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”) (Note 5). The Production Facilities segment also includes the Helix Fast Response System (“HFRS”), which provides certain operators access to our Q4000 and HP I vessels in the event of a well control incident in the Gulf of Mexico.

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Note 3 — Details of Certain Accounts

Other current assets and other assets, net consist of the following (in thousands):

	June 30, 2015	December 31, 2014
Note receivable [1]	$10,000	$17,500
Other receivables	632	423
Prepaid insurance	197	6,582
Other prepaids	10,452	15,541
Spare parts inventory	6,651	1,857
Income tax receivable	586	—
Value added tax receivable	8,051	9,326
Other	95	72
Total other current assets	$36,664	$51,301

	June 30, 2015	December 31, 2014
Note receivable [1]	$10,000	$10,000
Deferred dry dock expenses, net	26,061	11,631
Deferred financing costs, net (Note 6)	22,528	23,399
Intangible assets with finite lives, net	719	696
Charter fee deposit (Note 12)	12,544	12,544
Other	1,454	1,002
Total other assets, net	$73,306	$59,272

(1) Relates to the remaining balance of the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014. Interest on the note is payable quarterly at a rate of 6% per annum. Under the terms of the note, the remaining $20 million principal balance is required to be paid with a $10 million payment on December 31, 2015 and December 31, 2016.

Accrued liabilities consist of the following (in thousands):

	June 30, 2015	December 31, 2014
Accrued payroll and related benefits	$19,490	$61,246
Current asset retirement obligations	554	575
Unearned revenue	6,700	11,461
Accrued interest	4,882	4,221
Derivative liability (Note 14)	19,390	13,222
Taxes payable excluding income tax payable	6,583	6,236
Other	9,189	7,962
Total accrued liabilities	$66,788	$104,923

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Note 4 — Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of three months or less. The following table provides supplemental cash flow information (in thousands):

	Six Months Ended June 30,	
	2015	2014
Interest paid, net of interest capitalized	$3,729	$5,960
Income taxes paid	$13,285	$35,268

Our non-cash investing activities include accruals for property and equipment capital expenditures. These non-cash investing accruals totaled $18.3 million and $14.1 million as of June 30, 2015 and December 31, 2014, respectively. Additionally, our investing activities for the six-month period ended June 30, 2014 included a $30 million non-cash transaction related to the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014 (Note 3).

Note 5 — Equity Investments

As of June 30, 2015, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $78.6 million and $80.9 million as of June 30, 2015 and December 31, 2014, respectively (including net capitalized interest of $1.2 million at June 30, 2015 and December 31, 2014, respectively).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $67.0 million and $68.8 million as of June 30, 2015 and December 31, 2014, respectively (including capitalized interest of $3.8 million and $3.9 million at June 30, 2015 and December 31, 2014, respectively).

We received the following distributions from our equity method investments (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Deepwater Gateway	$1,700	$1,750	$2,700	$3,750
Independence Hub	440	500	840	1,300
Total	$2,140	$2,250	$3,540	$5,050

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Note 6 — Long-Term Debt

Scheduled maturities of our long-term debt outstanding as of June 30, 2015 are as follows (in thousands):

	Term Loan	Nordea Term Loan	MARAD Debt	2032 Notes (1)	Total
Less than one year	$30,000	$35,714	$5,783	$—	$71,497
One to two years	30,000	35,715	6,072	—	71,787
Two to three years	30,000	35,714	6,375	—	72,089
Three to four years	180,000	35,714	6,693	—	222,407
Four to five years	—	107,143	7,027	—	114,170
Over five years	—	—	60,054	200,000	260,054
Total debt	270,000	250,000	92,004	200,000	812,004
Current maturities	(30,000)	(35,714)	(5,783)	—	(71,497)
Long-term debt, less current maturities	240,000	214,286	86,221	200,000	740,507
Unamortized debt discount (2)	—	—	—	(17,992)	(17,992)
Long-term debt	$240,000	$214,286	$86,221	$182,008	$722,515

(1) Beginning in March 2018, the holders of our Convertible Senior Notes due 2032 may require us to repurchase these notes or we may at our option elect to repurchase these notes. The notes will mature in March 2032.

(2) Our Convertible Senior Notes due 2032 will increase to their face amount through accretion of non-cash interest charges through March 2018.

Included below is a summary of certain components of our indebtedness:

Credit Agreement

In June 2013, we entered into a credit agreement (the “Credit Agreement”) with a group of lenders pursuant to which we borrowed $300 million under the Credit Agreement’s term loan (the “Term Loan”) and, subject to the terms of the Credit Agreement, may borrow additional amounts (the “Revolving Loans”) and/or obtain letters of credit under a revolving credit facility (the “Revolving Credit Facility”) up to $600 million. Subject to lender participation, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. At June 30, 2015, we had no borrowings under the $600 million Revolving Credit Facility and our available borrowing capacity totaled $450.1 million, net of $16.7 million of letters of credit issued.

The Term Loan and the Revolving Loans (together, the “Loans”) bear interest, at our election, in relation to either the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans.

The Loans or portions thereof bearing interest at the base rate bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00% (1.00% to 3.00% following the amendment described below). The Loans or portions thereof bearing interest at a LIBOR rate bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00% (2.00% to 4.00% following the amendment described below). A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We currently also pay a fixed commitment fee of 0.50% on the unused portion

of our Revolving Credit Facility. The Term Loan currently bears interest at the one-month LIBOR rate plus 2.50%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $148.1 million of our borrowings under the Term Loan. The fixed LIBOR rates are between 74 and 75 basis points.

The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the "Loan Documents") include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement). In May 2015, we amended the Credit Agreement to revise the maximum permitted Consolidated Leverage Ratio as follows: 4.00 to 1.00 for the second quarter of 2015, 4.50 to 1.00 for the third quarter of 2015 through the fourth quarter of 2016, 4.00 to 1.00 for the first quarter of 2017, and 3.50 to 1.00 for the second quarter of 2017 and thereafter.

We have designated five of our foreign subsidiaries, and may designate any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the "Unrestricted Subsidiaries"), provided we meet certain liquidity requirements, in which case EBITDA (net of cash distributions to the parent) of the Unrestricted Subsidiaries is not included in the calculations with respect to our financial covenants. Our obligations under the Credit Agreement are guaranteed by our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets of the parent and our wholly owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited, plus pledges of up to two-thirds of the shares of certain foreign subsidiaries.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of $200 million in aggregate principal amount of Convertible Senior Notes due 2032 (the "2032 Notes"). The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes mature on March 15, 2032 unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes. We have the right and the intention to settle any such future conversions in cash.

Prior to March 20, 2018, the 2032 Notes are not redeemable. On or after March 20, 2018, we, at our option, may redeem some or all of the 2032 Notes in cash, at any time upon at least 30 days' notice, at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. In addition, the holders of the 2032 Notes may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the

principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the Indenture governing the 2032 Notes).

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception. As of June 30, 2015, the carrying amount of the equity component of the 2032 Notes was $22.5 million.

MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As required by the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date.

Nordea Credit Agreement

In September 2014, a wholly owned subsidiary incorporated in Luxembourg, Helix Q5000 Holdings S.à r.l. ("Q5000 Holdings"), entered into a credit agreement (the "Nordea Credit Agreement") with a syndicated bank lending group for a term loan (the "Nordea Term Loan") in an amount of up to $250 million. The Nordea Term Loan was funded in the amount of $250 million at the end of April 2015 at the time the Q5000 vessel was delivered. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., also a wholly owned Luxembourg subsidiary, guaranteed the Nordea Term Loan. The loan is secured by the Q5000 and its charter earnings as well as by a pledge of the shares of Q5000 Holdings. This indebtedness is nonrecourse to Helix.

The Nordea Term Loan bears interest at a LIBOR rate plus a margin of 2.5%, with an undrawn fee of 0.875% prior to funding on April 30, 2015. The Nordea Term Loan matures on April 30, 2020 and is repayable in scheduled principal installments of $8.9 million, payable quarterly, with a balloon payment of $80.4 million at maturity. Q5000 Holdings may elect to prepay amounts outstanding under the Nordea Term Loan without premium or penalty, but may not reborrow any amounts prepaid. Installment amounts are subject to adjustment for any prepayments on this debt. In certain circumstances, Q5000 Holdings will be required to prepay the loan. In June 2015, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $187.5 million of our borrowings under the Nordea Term Loan. The fixed LIBOR rates are between 149 and 152 basis points.

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The Nordea Credit Agreement and related loan documents include terms and conditions, including covenants, that are considered customary for this type of transaction. The covenants include restrictions on Q5000 Holdings's ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, and pay dividends. In addition, the Nordea Credit Agreement obligates Q5000 Holdings to meet certain minimum financial requirements, including liquidity, consolidated debt service coverage and collateral maintenance.

Other

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of June 30, 2015, we were in compliance with these covenants.

Unamortized deferred financing costs are included in "Other assets, net" in the accompanying condensed consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs (in thousands):

	June 30, 2015			December 31, 2014		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loan (matures June 2018)	$3,638	$(1,455)	$2,183	$3,638	$(1,091)	$2,547
Revolving Credit Facility (matures June 2018)	14,787	(5,351)	9,436	13,275	(3,982)	9,293
2032 Notes (mature March 2032)	3,759	(2,070)	1,689	3,759	(1,763)	1,996
MARAD Debt (matures February 2027)	12,200	(6,467)	5,733	12,200	(6,223)	5,977
Nordea Term Loan	3,607	(120)	3,487	3,586	—	3,586
Total deferred financing costs	$37,991	$(15,463)	$22,528	$36,458	$(13,059)	$23,399

The following table details the components of our net interest expense (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Interest expense	$9,751	$7,160	$18,160	$15,522
Interest income	(457)	(655)	(1,107)	(1,372)
Capitalized interest	(4,059)	(1,988)	(7,748)	(5,150)
Net interest expense	$5,235	$4,517	$9,305	$9,000

Note 7 — Income Taxes

Our estimated annual effective tax rate, adjusted for discrete tax items, is applied to interim periods' pretax earnings. We believe that our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

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The effective tax rates for the three- and six-month periods ended June 30, 2015 were (30.4)% and 5.7%, respectively. The effective tax rates for the three- and six-month periods ended June 30, 2014 were 23.3% and 25.3%, respectively. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

Income taxes have been provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction. The primary differences between the U.S. statutory rate and our effective rate are as follows:

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
U.S. statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(54.6)	(8.4)	(31.5)	(8.3)
Tax benefits previously unrecognized	—	(4.5)	—	(2.3)
Other	(10.8)	1.2	2.2	0.9
Effective rate	(30.4)%	23.3 %	5.7 %	25.3 %

Note 8 — Accumulated Other Comprehensive Income (Loss) (“OCI”)

The components of Accumulated OCI are as follows (in thousands):

	June 30, 2015	December 31, 2014
Cumulative foreign currency translation adjustment	$(28,141)	$(30,161)
Unrealized loss on hedges, net (1)	(34,323)	(32,091)
Accumulated other comprehensive loss	$(62,464)	$(62,252)

(1) Amounts relate to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III charters as well as interest rate swap contracts for the Term Loan and the Nordea Term Loan, and are net of deferred income taxes totaling $18.5 million at June 30, 2015 and $17.3 million at December 31, 2014 (Note 14).

Note 9 — Earnings Per Share

We have shares of restricted stock issued and outstanding, which currently are unvested. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding unrestricted common stock and the shares are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share (“EPS”) amounts under the two class method in periods in which we have earnings from continuing operations.

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The presentation of basic EPS amounts on the face of the accompanying condensed consolidated statements of operations is computed by dividing the net income applicable to our common shareholders by the weighted average shares of our outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (income) and denominator (shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying condensed consolidated statements of operations are as follows (in thousands):

	Three Months Ended June 30, 2015		Three Months Ended June 30, 2014	
	Income	Shares	Income	Shares
Basic:				
Net income (loss) applicable to common shareholders	$(2,635)		$57,782	
Less: Undistributed income allocated to participating securities	—		(300)	
Undistributed income (loss) allocated to common shares	$(2,635)	105,357	$57,482	104,992
Diluted:				
Undistributed income (loss) allocated to common shares	$(2,635)	105,357	$57,482	104,992
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	303
Undistributed income reallocated to participating securities	—	—	1	—
Net income (loss) applicable to common shareholders	$(2,635)	105,357	$57,483	105,295

	Six Months Ended June 30, 2015		Six Months Ended June 30, 2014	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$17,007		$111,501	
Less undistributed income allocated to participating securities	(96)		(586)	
Undistributed income allocated to common shares	$16,911	105,324	$110,915	105,059
Diluted:				
Undistributed income allocated to common shares	$16,911	105,324	$110,915	105,059
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	300
Undistributed income reallocated to participating securities	—	—	2	—
Net income applicable to common shareholders	$16,911	105,324	$110,917	105,359

Approximately 8.0 million of potentially dilutive shares related to the 2032 Notes were excluded from the diluted EPS calculation for the three- and six-month periods ended June 30, 2015 and 2014 because we have the right, intention and ability to settle any such future conversions in cash (Note 6).

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Note 10 — Employee Benefit Plans

Long-Term Incentive Stock-Based Plan

As of June 30, 2015, there were 6.1 million shares of our common stock available for issuance under our active long-term incentive stock-based plan, the 2005 Long-Term Incentive Plan, as amended and restated effective May 9, 2012 (the "2005 Incentive Plan"). During the six-month period ended June 30, 2015, the following grants of share-based awards were made under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2015 (1)	289,163	$21.70	33% per year over three years
January 2, 2015 (2)	289,163	$25.06	100% on January 1, 2018
January 5, 2015 (3)	3,946	$21.66	100% on January 1, 2017
January 12, 2015 (1)	3,866	$19.40	33% per year over three years
January 12, 2015 (2)	3,866	$25.06	100% on January 11, 2018
February 1, 2015 (1)	2,664	$18.77	33% per year over three years
February 1, 2015 (2)	2,664	$25.06	100% on January 31, 2018
April 1, 2015 (3)	6,476	$14.96	100% on January 1, 2017

(1) Reflects the grant of restricted stock to our executive officers and selected management employees.

(2) Reflects the grant of performance share units ("PSUs") to our executive officers and selected management employees. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs may be settled in either cash or shares of our common stock at the discretion of the Compensation Committee of our Board of Directors.

(3) Reflects the grant of restricted stock to certain members of our Board of Directors who have made an election to take their quarterly fees in stock in lieu of cash.

Compensation cost for restricted stock is recognized over its vesting period on a straight-line basis. For the three- and six-month periods ended June 30, 2015, $1.5 million and $2.9 million, respectively, were recognized as stock-based compensation expense related to restricted stock. For the three- and six-month periods ended June 30, 2014, $1.3 million and $2.5 million, respectively, were recognized as stock-based compensation expense related to restricted stock and restricted stock units.

The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. Until December 2014, the PSUs were being treated as an equity award. Accordingly, compensation expense associated with the PSUs was fixed, as represented by the number of PSUs multiplied by their respective grant date fair value, and the fixed amount was amortized on a straight-line basis over the three-year vesting period. In connection with the vesting of the 2012 PSU awards that occurred in January 2015, the decision was made by the Compensation Committee of our Board of Directors to settle these PSUs with a cash payment of $4.5 million (rather than an equivalent number of shares of our common stock, which was the default provision of the PSU awards). Accordingly, PSUs are now accounted for as a liability plan and changes in fair value of the awards are recognized in earnings. For the three-month period ended June 30, 2015, $0.2 million was recognized as stock-based compensation expense related to PSUs. For the six-month period ended June 30, 2015, we recorded a net reduction of $0.9 million of previously recognized compensation cost to reflect the estimated fair value of unvested PSUs as of June 30, 2015. For the three-and six-month periods ended June 30, 2014, $0.5 million and $1.0 million, respectively, were recognized as stock-based compensation expense related to PSUs.

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Long-Term Incentive Cash Plans

We have certain long-term incentive cash plans (the “LTI Cash Plans”) that provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). Payment amounts under these awards are calculated based on the ratio of the average stock price during the applicable measurement period over the original base price determined by the Compensation Committee of our Board of Directors at the time of the award. Cash payments under these awards are made each year on the anniversary date of the award. Cash awards granted since 2012 have a vesting period of three years while those granted prior to 2012 have a vesting period of five years. The LTI Cash Plans are considered liability plans and as such are re-measured to fair value each reporting period with corresponding changes in the liability amount being reflected in our results of operations.

The cash awards granted under the LTI Cash Plans to our executive officers and selected management employees totaled $8.9 million in 2014. No long-term incentive cash awards were granted in 2015. For the three- and six-month periods ended June 30, 2015, we recorded reductions of $0.6 million and $2.5 million, respectively, of previously recognized compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans, reflecting the effect the decrease in our stock price since December 31, 2014 had on the value of our liability plan. For the three- and six-month periods ended June 30, 2014, total compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans was $3.7 million and $5.4 million, respectively. The liability balance for the cash awards issued under the LTI Cash Plans was $1.2 million at June 30, 2015 and $12.8 million at December 31, 2014.

Employee Stock Purchase Plan

We also have an employee stock purchase plan (the “ESPP”). The ESPP has 1.5 million shares authorized for issuance, of which 1.0 million shares were available for issuance as of June 30, 2015. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.3 million and $0.6 million, respectively, for the three- and six-month periods ended June 30, 2015. For the three- and six-month periods ended June 30, 2014, share-based compensation expense with respect to the ESPP was $0.3 million and $0.5 million, respectively.

For more information regarding our employee benefit plans, including our long-term incentive stock-based and cash plans and our employee stock purchase plan, see Note 8 to our 2014 Form 10-K.

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Note 11 — Business Segment Information

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Q5000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. Our well intervention segment also includes certain intervention riser systems that are available on a rental basis. Our Robotics segment includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates five chartered ROV and trencher support vessels. The Production Facilities segment includes the HP I as well as our investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. The results of our previously reported Subsea Construction segment are immaterial and thus no longer meet the threshold to be separately reported as a business segment. These results are now aggregated within "Other" for all periods presented in this Quarterly Report on Form 10-Q. All material intercompany transactions between the segments have been eliminated.

We evaluate our performance primarily based on operating income of each reportable segment. Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments. Certain financial data by reportable segment are summarized as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net revenues —				
Well Intervention	$85,675	$181,218	$189,726	$340,918
Robotics	75,101	119,704	155,272	207,594
Production Facilities	20,293	24,049	38,678	47,189
Other	—	—	—	358
Intercompany elimination	(15,053)	(19,384)	(28,019)	(36,900)
Total	$166,016	$305,587	$355,657	$559,159
Income (loss) from operations —				
Well Intervention	$4,135	$64,775	$18,929	$113,508
Robotics	4,303	20,799	13,760	32,018
Production Facilities	8,444	10,459	13,022	21,843
Corporate and other	(9,009)	(17,322)	(15,616)	(20,512)
Intercompany elimination	(199)	45	(93)	(1,153)
Total	$7,674	$78,756	$30,002	$145,704
Equity in earnings (losses) of investments	$(323)	$(507)	$(302)	$201

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Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Well Intervention	$6,417	$7,956	$11,363	$13,417
Robotics	8,636	11,428	16,656	23,483
Total	$15,053	$19,384	$28,019	$36,900

The following table reflects total assets by reportable segment (in thousands):

	June 30, 2015	December 31, 2014
Well Intervention	$1,805,388	$1,470,349
Robotics	304,357	299,701
Production Facilities	446,199	459,427
Corporate and other	378,252	471,221
Total	$2,934,196	$2,700,698

Note 12 — Commitments and Contingencies and Other Matters

Commitments

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represented the majority of the costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments were made as a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. The vessel was delivered to us in the second quarter of 2015 and is currently in transit to the Gulf of Mexico. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects. The Nordea Term Loan was funded at the time the Q5000 vessel was delivered to us (Note 6). At June 30, 2015, our total investment in the Q5000 was $479.0 million, including $386.5 million of scheduled payments made to the shipyard.

In February 2013, we contracted to charter the Grand Canyon II and the Grand Canyon III for use in our robotics operations. The terms of the charters are for five years from the respective delivery dates. We took delivery of the Grand Canyon II in late April 2015 and received a $4.7 million non-refundable payment from the shipyard that constructed the vessel related to the delayed delivery of the vessel. This payment will be amortized as a reduction in our cost of sales over the five-year charter for the vessel. The delivery of the Grand Canyon III has been extended until February 2016.

In September 2013, we executed a second contract with the same shipyard in Singapore that constructed the Q5000. This contract is for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is to be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the original terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% was to be paid upon the delivery of the vessel. Pursuant to an amendment we entered into with the shipyard in June 2015, the remaining 80% will now be paid in two

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installments, with 20% in June 2016 and 60% upon the delivery of the vessel. We agreed to pay the shipyard incremental costs of up to $14.5 million to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017. We paid $7.3 million of these costs in July 2015 and the remaining costs will be paid upon the delivery of the vessel. At June 30, 2015, our total investment in the Q7000 was $105.8 million, including the $69.2 million paid to the shipyard upon signing the contract.

In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. At June 30, 2015, our total investment in the topside equipment for the two vessels was $85.7 million. In November 2014, we paid a charter fee deposit of $12.5 million.

Contingencies and Claims

We believe that there are currently no contingencies which would have a material effect on our financial position, results of operations or cash flows.

Litigation

We are involved in various legal proceedings, some involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Note 13 — Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).
(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the short-term nature of these instruments. The following tables provide additional information relating to other financial instruments measured at fair value on a recurring basis (in thousands):

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	Fair Value Measurements at June 30, 2015 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Interest rate swaps	$—	$905	$—	$905	(c)
Liabilities:					
Foreign exchange contracts	—	54,460	—	54,460	(c)
Interest rate swaps	—	2,440	—	2,440	(c)
Total net liability	$—	$55,995	$—	$55,995	

	Fair Value Measurements at December 31, 2014 Using				
	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Interest rate swaps	$—	$369	$—	$369	(c)
Liabilities:					
Foreign exchange contracts	—	50,428	—	50,428	(c)
Interest rate swaps	—	561	—	561	(c)
Total net liability	$—	$50,620	$—	$50,620	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. See Note 14 for further discussion on fair value of our derivative instruments.

The fair value of our long-term debt is as follows (in thousands):

	June 30, 2015		December 31, 2014	
	Carrying Value	Fair Value (2)	Carrying Value	Fair Value (2)
Term Loan (matures June 2018)	$270,000	$265,106	$277,500	$270,563
Nordea Term Loan (matures April 2020)	250,000	242,031	—	—
MARAD Debt (matures February 2027)	92,004	103,494	94,792	104,830
2032 Notes (mature March 2032) (1)	200,000	191,624	200,000	222,900
Total debt	$812,004	$802,255	$572,292	$598,293

(1) Carrying amount excludes the related unamortized debt discount of $18.0 million at June 30, 2015 and $20.9 million at December 31, 2014.

(2) The estimated fair value of the 2032 Notes was determined using Level 1 inputs using the market approach. The fair value of the Term Loan, the Nordea Term Loan and the MARAD Debt was estimated using Level 2 fair value inputs under the market approach. The fair value of the Term Loan, the Nordea Term Loan and the MARAD Debt

was determined using a third party evaluation of the remaining average life and outstanding principal balance of the indebtedness as compared to other obligations in the marketplace with similar terms.

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Note 14 — Derivative Instruments and Hedging Activities

Our operations are exposed to market risk associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the fair value of derivatives that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of Accumulated OCI (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

For additional information regarding our accounting for derivatives, see Notes 2 and 15 to our 2014 Form 10-K.

Interest Rate Risk

From time to time, we enter into interest rate swaps to stabilize cash flows related to our long-term variable interest rate debt. In September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan borrowings (Note 6). These contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally, in June 2015, we entered into various interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Term Loan borrowings (Note 6). These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. Our interest rate swap contracts qualify for hedge accounting treatment. Changes in the fair value of interest rate swaps are deferred to the extent the swaps are effective. These changes are recorded as a component of Accumulated OCI until the anticipated interest is recognized as interest expense. The ineffective portion of the interest rate swaps, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We enter into foreign currency exchange contracts from time to time to stabilize expected cash outflows related to our vessel charters that are denominated in foreign currencies.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively.

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Quantitative Disclosures Relating to Derivative Instruments

The following table presents the fair value and balance sheet classification of our derivative instruments that were designated as hedging instruments (in thousands):

	June 30, 2015 Balance Sheet Location	Fair Value	December 31, 2014 Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$905	Other assets, net	$369
		$905		$369
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$16,950	Accrued liabilities	$12,661
Interest rate swaps	Accrued liabilities	2,440	Accrued liabilities	561
Foreign exchange contracts	Other non-current liabilities	37,510	Other non-current liabilities	37,767
		$56,900		$50,989

For the three- and six-month periods ended June 30, 2015, we recorded gains (losses) of $0.2 million and $(3.2) million, respectively, in “Other expense, net” in the accompanying condensed consolidated statement of operations related to ineffectiveness associated with our foreign currency hedges with respect to the Grand Canyon III charter payments as a result of the deferral of the vessel’s delivery until February 2016. Ineffectiveness associated with our cash flow hedges was immaterial for the three- and six-month periods ended June 30, 2014. The following tables present the impact that derivative instruments designated as cash flow hedges had on our Accumulated OCI (net of tax) and our condensed consolidated statements of operations (in thousands). We estimate that as of June 30, 2015, $10.5 million of losses in Accumulated OCI associated with our derivatives is expected to be reclassified into earnings within the next 12 months.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Foreign exchange contracts	$5,002	$(2,134)	$(1,359)	$890
Interest rate swaps	(709)	(153)	(873)	(114)
	$4,293	$(2,287)	$(2,232)	$776

	Location of Loss Reclassified from Accumulated OCI into Earnings	Loss Reclassified from Accumulated OCI into Earnings			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
Foreign exchange contracts	Cost of sales	$(2,921)	$(217)	$(4,395)	$(431)
Interest rate swaps	Net interest expense	(337)	(393)	(536)	(837)
		$(3,258)	$(610)	$(4,931)	$(1,268)

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

This Quarterly Report on Form 10-Q contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward-looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potential," "should," "co terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which are subject to change;
- statements regarding the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of our Q7000 vessel and the construction of two chartered vessels to be used in connection with our contracts to provide well intervention services offshore Brazil (Note 12);
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding our backlog and long-term contracts;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements regarding our ability to retain key members of our senior management and key employees;
- statements regarding the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

Although we believe that the expectations reflected in these forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- impact of potential cancellation, deferral or modification of our work or contracts by our customers;

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- unexpected delays in the delivery or chartering of new vessels for our well intervention and robotics fleet, including the Q7000, the Grand Canyon III and the two newbuild chartered vessels to be used to perform contracted well intervention work offshore Brazil;
- unexpected future capital expenditures (including the amount and nature thereof);
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations;
- the effects of our indebtedness;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those described in Item 1A. “Risk Factors” in our 2014 Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

Executive Summary

Business Strategy

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We believe that focusing on these services will deliver favorable long-term financial returns. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. On our well intervention side, we took delivery of the Q5000 at the end of April 2015. Our well intervention fleet will expand following the completion and delivery in 2017 of a second newbuild semi-submersible vessel currently under construction, the Q7000, and the expected delivery in 2016 of two newbuild monohull vessels, which we will charter in connection with the well intervention agreements that we entered into with Petrobras. On our robotics side, we took delivery of the Grand Canyon II in late April 2015. We will further expand our robotics operations by acquiring additional ROVs as well as chartering the Grand Canyon III, currently scheduled to commence in February 2016.

On January 5, 2015, Helix, OneSubsea LLC, OneSubsea B.V., Schlumberger Technology Corporation, Schlumberger B.V. and Schlumberger Oilfield Holdings Ltd. entered into a Strategic Alliance Agreement and related agreements for the parties’ strategic alliance to design, develop, manufacture, promote, market and sell on a global basis integrated equipment and services for subsea well intervention. The alliance is expected to leverage the parties’ capabilities to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies.

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Economic Outlook and Industry Influences

Demand for our services is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by domestic and global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- supply and demand for oil and natural gas, especially in the United States, Europe, China and India;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the Organization of Petroleum Exporting Countries (“OPEC”);
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- domestic and international tax laws, regulations and policies.

Global prices for oil and natural gas have declined significantly from amounts that were realized around mid-year 2014. The oil price decline accelerated during the fourth quarter of 2014 following the announcement that OPEC would not reduce its daily production quotas to support global oil prices. Oil prices have decreased by over 10% since the end of June 2015 to a low of approximately $50 per barrel, further reflecting the increased volatility of crude oil prices as they relate to developing global events. Some of these recent global events include the evolving debt crisis in Greece, the recent turmoil in the equity markets in China and the growing expectation that a potential easing of sanctions on Iran in connection with the recently announced nuclear agreement is likely to result in additional crude oil being released into an oversupplied global market. The significant decrease in oil and gas prices over the past 12 months is attributable to a global supply and demand imbalance which reflects both increased production in certain countries (primarily the United States) and certain specific weakening in the global economy affecting Asia and Europe. In light of the sharp decline in oil and gas prices, many oil and gas companies announced substantial reductions in their planned capital spending for 2015 and may do so again for 2016 if oil and gas prices do not increase. Any additional news suggesting weak or declining economic data could affect global equity and the oil and gas markets, which could affect normal business activities. Weaker global equity and oil and gas markets could potentially reduce investment in offshore oil and gas capital projects, which may affect rates that drilling rig contractors can charge for their services. We believe that capital is more likely to be constrained for new offshore projects, for example for exploration drilling projects, than on projects that span the life of an oil and gas field’s production. However, during periods of sustained low oil and gas prices similar as experienced during 2015, no one in the industry is immune to the effect of capital spending reductions, including us. Our Well Intervention and Robotics operations are intended to service the life span of an oil and gas field as well as to provide abandonment services at the end of the life of a field as required by governmental regulations. Thus over the longer term, we believe that fundamentals for our business remain favorable as the need for continual oil and gas production is the primary driver of demand for our services.

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In addition, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term world demand for oil and natural gas emphasizing the need for continual production and the replacement thereof; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) a general long-term growth trend in offshore activity and deepwater well count; and (6) an increasing number of subsea developments.

Helix Fast Response System

We developed the HFRS as a culmination of our experience as a responder in the Macondo well control and containment efforts. The HFRS centers on two of our vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements effective April 1, 2013 with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants, to perform the same functions as CGA with respect to the HFRS. In March 2015, HWCG LLC exercised a one-year option to extend the agreement with us through March 31, 2018.

RESULTS OF OPERATIONS

We have three reportable business segments: Well Intervention, Robotics and Production Facilities. All material intercompany transactions between the segments have been eliminated in our condensed consolidated financial statements, including our consolidated results of operations.

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our services cover the lifecycle of an offshore oil or gas field. We operate primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and intend to increase our operations offshore Brazil. In addition, our Robotics operations are often contracted for the development of renewable energy projects (wind farms). As of June 30, 2015, our consolidated backlog that is supported by written agreements or contracts totaled $2.1 billion, of which $303.7 million is expected to be performed over the remainder of 2015. The substantial majority of our backlog is associated with our Well Intervention business segment. As of June 30, 2015, our well intervention backlog was $1.8 billion, including $188.6 million expected to be performed over the remainder of 2015. Our five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel and our four-year agreements with Petrobras, both of which are scheduled to commence in 2016, represent approximately 72% of our total backlog. Backlog contracts are cancelable sometimes without penalty. In addition, if there are cancellation fees, the amount of those fees can be substantially less than the rates we would have generated had we performed the contract. Accordingly, backlog is not necessarily a reliable indicator of total annual revenues for our services as contracts may be added, renegotiated, deferred, canceled and in many cases modified while in progress.

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Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as a numerical measure of a company's historical or future performance, financial position, or cash flows that includes or excludes amounts from the most directly comparable measure under U.S. GAAP. We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required by our debt covenants. We believe our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA as net income plus income taxes, depreciation and amortization expense, and net interest expense and other. In the following reconciliation, we provide amounts as reflected in our accompanying condensed consolidated financial statements unless otherwise footnoted. This means that these amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and the gain or loss on disposition of assets.

Other companies may calculate their measures of EBITDA and Adjusted EBITDA differently than we do, which may limit their usefulness as comparative measures. Because EBITDA is not a financial measure calculated in accordance with U.S. GAAP, it should not be considered in isolation or as a substitute for net income attributable to common shareholders or cash flows from operations, but used as a supplement to these GAAP financial measures. The reconciliation of our net income to EBITDA and Adjusted EBITDA is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss) applicable to common shareholders	$(2,635)	$57,782	$17,007	$111,501
Adjustments:				
Net income applicable to noncontrolling interests	—	—	—	503
Income tax provision	614	17,529	1,021	37,946
Net interest expense and other	10,271	4,534	15,497	9,827
Depreciation and amortization	27,439	28,127	53,528	52,853
EBITDA	35,689	107,972	87,053	212,630
Adjustments:				
Noncontrolling interests	—	—	—	(661)
(Gain) loss on disposition of assets, net	—	1,078	—	(10,418)
ADJUSTED EBITDA	$35,689	$109,050	$87,053	$201,551

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Comparison of Three Months Ended June 30, 2015 and 2014

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Three Months Ended June 30, 2015	2014	Increase/ (Decrease)
Net revenues —			
Well Intervention	$85,675	$181,218	$(95,543)
Robotics	75,101	119,704	(44,603)
Production Facilities	20,293	24,049	(3,756)
Intercompany elimination	(15,053)	(19,384)	4,331
	$166,016	$305,587	$(139,571)
Gross profit —			
Well Intervention	$7,254	$68,543	$(61,289)
Robotics	9,420	30,428	(21,008)
Production Facilities	8,578	10,625	(2,047)
Corporate and other	(845)	(503)	(342)
Intercompany elimination	(199)	45	(244)
	$24,208	$109,138	$(84,930)
Gross margin —			
Well Intervention	8%	38%	
Robotics	13%	25%	
Production Facilities	42%	44%	
Total company	15%	36%	
Number of vessels or ROV assets (1) / Utilization (2)			
Well Intervention vessels	4/63%	5/98%	
ROVs	61/61%	60/81%	
Robotics vessels	5/81%	7/89%	

(1) Represents number of vessels or ROV assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. The Seawell was excluded from the numbers for the second quarter of 2015 as it was out of service for the entire quarter undergoing major capital upgrades.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels or ROV assets generated revenues by the total number of calendar days in the applicable period.

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Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Three Months Ended June 30, 2015	2014	Increase/ (Decrease)
Well Intervention	$6,417	$7,956	$(1,539)
Robotics	8,636	11,428	(2,792)
	$15,053	$19,384	$(4,331)

Net Revenues. Our total net revenues decreased by 46% for the three-month period ended June 30, 2015 as compared to the same period in 2014. The decreased revenues for the three-month period in 2015 included the adverse impact of reduced opportunities for near term work and the acceptance of lower margin work for some of our assets following the industry-wide reaction to the substantial downturn in the oil and natural gas market since mid-year 2014.

Our Well Intervention revenues decreased by 53% for the three-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting decreased utilization of our in-service well intervention vessels and the Seawell being out of service for the entire second quarter of 2015 undergoing certain capital upgrades intended to extend the useful life of the vessel. In the North Sea, the Skandi Constructor worked 62 days during the second quarter of 2015 as compared to being fully utilized in the same period in 2014. The Well Enhancer was fully utilized during both periods. In the Gulf of Mexico, the Q4000 worked 26 days during the second quarter of 2015 following completion of its regularly scheduled regulatory dry dock in early June 2015. During the second quarter of 2014, the Q4000 was in service for 82 days. The Helix 534 was utilized for 50 days in the second quarter of 2015 as compared to full utilization in the same period in 2014. In addition, Well Intervention revenues were adversely impacted by a $2.5 million adjustment to correct amounts previously reported in 2014 (Note 1).

Robotics revenues decreased by 37% for the three-month period ended June 30, 2015 as compared to the same period in 2014. The decrease primarily reflected lower utilization of our Robotics assets and 148 fewer days of spot vessel utilization as some units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas market downturn.

Our Production Facilities revenues decreased by 16% for the three-month period ended June 30, 2015 as compared to the same period in 2014, which reflected the decrease in our variable throughput fee as a result of both the decline in oil prices and reduced production.

Gross Profit. Our total gross profit decreased by 78% for the three-month period ended June 30, 2015 as compared to the same period in 2014. The gross profit related to our Well Intervention segment decreased by 89% for the three-month period ended June 30, 2015 as compared to the same period in 2014 reflecting significantly reduced revenues as a result of the Seawell and the Q4000 being in dry dock and the Skandi Constructor and the Helix 534 being idle for considerable periods of time during the second quarter of 2015 due to lack of available projects.

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The gross profit associated with our Robotics segment decreased by 69% for the three-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting decreased utilization for our Robotics assets.

The gross profit related to our Production Facilities segment decreased by 19% for the three-month period ended June 30, 2015 as compared to the same period in 2014. The decrease primarily reflected the decrease in revenues associated with our variable throughput fee.

Loss on Disposition of Assets. The $1.1 million loss on disposition of assets for the three-month period ended June 30, 2014 relates to the loss of one of our ROVs in the Gulf of Mexico.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $12.8 million for the three-month period ended June 30, 2015 as compared to the same period in 2014. The decrease was primarily attributable to a reduction in payroll related costs including costs associated with our variable performance-based incentive compensation programs (Note 10). In addition, selling, general and administrative expenses included charges of $2.5 million and $5.2 million, respectively, in the comparable year-over-year periods, both of which were associated with the provision for uncertain collection of a portion of our trade receivables for our Robotics segment.

Net Interest Expense. Our net interest expense increased by $0.7 million for the three-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting interest expense associated with the Nordea Term Loan (Note 6). The increase in interest expense was partially offset by an increase in capitalized interest. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $4.1 million for the second quarter of 2015 as compared to $2.0 million for the second quarter of 2014.

Other Expense, Net. Our other expense, net, increased by $5.0 million for the three-month period ended June 30, 2015 as compared to the same period in 2014. The increase primarily reflected foreign currency transaction losses of $5.2 million during the second quarter of 2015 as a result of foreign exchange fluctuations in our non-U.S. dollar functional currencies.

Other Income – Oil and Gas. Our other income – oil and gas decreased by $0.7 million for the three-month period ended June 30, 2015 as compared to the same period in 2014. The decrease reflects declining oil prices and their effect on our overriding royalty income.

Income Tax Provision. Income taxes reflected expenses of $0.6 million for the three-month period ended June 30, 2015 as compared to $17.5 million for the same period last year. The variance primarily reflected decreased profitability in the current year period. Applying the estimated annual effective tax rate of 5.7% to the second quarter year-to-date pretax earnings resulted in an effective tax rate of (30.4)% for the three-month period ended June 30, 2015. The effective tax rate for the same period in 2014 was the 23.3%. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

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Comparison of Six Months Ended June 30, 2015 and 2014

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Six Months Ended June 30, 2015	2014	Increase/ (Decrease)
Net revenues —			
Well Intervention	$189,726	$340,918	$(151,192)
Robotics	155,272	207,594	(52,322)
Production Facilities	38,678	47,189	(8,511)
Other	—	358	(358)
Intercompany elimination	(28,019)	(36,900)	8,881
	$355,657	$559,159	$(203,502)
Gross profit —			
Well Intervention	$25,802	$121,332	$(95,530)
Robotics	22,110	43,773	(21,663)
Production Facilities	13,347	22,161	(8,814)
Corporate and other	(2,011)	(1,129)	(882)
Intercompany elimination	(93)	(1,153)	1,060
	$59,155	$184,984	$(125,829)
Gross margin —			
Well Intervention	14%	36%	
Robotics	14%	21%	
Production Facilities	35%	47%	
Total company	17%	33%	
Number of vessels or ROV assets (1) / Utilization (2)			
Well Intervention vessels	4/65%	5/95%	
ROVs	61/61%	62/76%	
Robotics vessels	5/83%	7/85%	

(1) Represents number of vessels or ROV assets as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. The Seawell was excluded from the numbers for the first half of 2015 as it was out of service undergoing major capital upgrades.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels or ROV assets generated revenues by the total number of calendar days in the applicable period.

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Intercompany segment amounts are derived primarily from equipment and services provided to other business segments at rates consistent with those charged to third parties. Intercompany segment revenues are as follows (in thousands):

	Six Months Ended June 30, 2015	2014	Increase/ (Decrease)
Well Intervention	$11,363	$13,417	$(2,054)
Robotics	16,656	23,483	(6,827)
	$28,019	$36,900	$(8,881)

Net Revenues. Our total net revenues decreased by 36% for the six-month period ended June 30, 2015 as compared to the same period in 2014. In general, decreased revenues for the six-month period in 2015 reflected both the reduced opportunities for near term work and the acceptance of lower margin work for some of our assets following the industry-wide reaction to the substantial downturn in the oil and natural gas market.

Our Well Intervention revenues decreased by 44% for the six-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting decreased utilization of our in-service well intervention vessels and the Seawell being out of service for the entire first half of 2015 undergoing certain capital upgrades intended to extend the useful life of the vessel. In the North Sea, the Skandi Constructor was 40% utilized for the entire first half of 2015 primarily due to the vessel being idle for the majority of the first four months of 2015 as compared to being nearly fully utilized for the first half of 2014. The Well Enhancer was essentially fully utilized during the six-month period ended June 30, 2015, while the vessel was in regulatory dry dock for 24 days in January 2014. In the Gulf of Mexico, we attempted to arrange replacement projects to fill the 150-day void in the Helix 534's schedule caused by a contract cancellation (for which we received a termination fee of $11.6 million). We were successful in filling all but 26 days in the first quarter of 2015. However, we only managed to utilize the vessel for 50 days during the second quarter of 2015. The Helix 534 was idle for the entire month of June and is currently preparing to undergo its regularly scheduled regulatory dry dock in the third quarter of 2015, which is anticipated to keep the vessel out of service for approximately 45 days. The Q4000 was utilized for 108 days during the first half of 2015. Idle time for the Q4000 primarily reflected it completing its regularly scheduled regulatory dry dock in the second quarter of 2015 (64 days) as well as some downtime attributable to intervention riser system mechanical issues in January 2015. We are currently considering various options that would reduce the amount of available vessel days for hire in the second half of 2015. Some of these options include warm stacking one or more of our vessels, including the Seawell in the North Sea region and the Helix 534 in the Gulf of Mexico.

Robotics revenues decreased by 25% for the six-month period ended June 30, 2015 as compared to the same period in 2014. The decrease primarily reflected lower utilization of our Robotics assets and 184 fewer days of spot vessel utilization as some units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas market downturn. However, our chartered ROV and trencher support vessels maintained high utilization rates reflecting full utilization of the Grand Canyon for a trenching project offshore Qatar.

Our Production Facilities revenues decreased by 18% for the six-month period ended June 30, 2015 as compared to the same period in 2014, which reflected the decrease in our variable throughput fee as a result of both the decline in oil prices and reduced production. The reduced production primarily reflected the Phoenix field being shut in for the majority of March 2015 for some development activities within the field and during which time the HP I underwent required maintenance. The Phoenix field recommenced production in late March 2015.

Gross Profit. Our total gross profit decreased by 68% for the six-month period ended June 30, 2015 as compared to the same period in 2014. The gross profit related to our Well Intervention segment decreased by 79% for the six-month period ended June 30, 2015 as compared to the same period in 2014 reflecting reduced revenues as a result of the Seawell and the Q4000 being in dry dock and the Skandi Constructor and the Helix 534 being idle for considerable periods of time during the first half of 2015 due to lack of available projects.

The gross profit associated with our Robotics segment decreased by 49% for the six-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting decreased utilization for our Robotics assets.

The gross profit related to our Production Facilities segment decreased by 40% for the six-month period ended June 30, 2015 as compared to the same period in 2014. The decrease primarily reflected the decrease in revenues associated with our variable throughput fee and increased maintenance costs incurred in March 2015 while the HP I was disconnected from the production buoy at the Phoenix field.

Gain on Disposition of Assets, Net. The $10.4 million net gain on disposition of assets for the six-month period ended June 30, 2014 primarily reflected a $10.5 million gain associated with the sale of our Ingleside spoolbase in January 2014.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $20.5 million for the six-month period ended June 30, 2015 as compared to the same period in 2014. The decrease was primarily attributable to a reduction in payroll related costs including costs associated with our variable performance-based incentive compensation programs (Note 10). In addition, selling, general and administrative expenses included charges of $3.0 million and $5.2 million, respectively, in the comparable year-over-year periods, both of which were associated with the provision for uncertain collection of a portion of our trade receivables.

Equity in Earnings (Losses) of Investments. Equity in earnings (losses) of investments decreased by $0.5 million for the six-month period ended June 30, 2015 as compared to the same period in 2014. The decrease primarily reflected lower revenues for both Deepwater Gateway and Independence Hub as a result of lower production at the fields being processed at each facility.

Net Interest Expense. Our net interest expense increased by $0.3 million for the six-month period ended June 30, 2015 as compared to the same period in 2014 primarily reflecting interest expense associated with the Nordea Term Loan (Note 6). The increase in interest expense was partially offset by an increase in capitalized interest. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled $7.7 million for the first half of 2015 as compared to $5.2 million for the same period in 2014.

Other Expense, Net. We reported other expense, net, of $6.2 million for the six-month period ended June 30, 2015 as compared to $0.8 million for the same period in 2014. These amounts primarily reflected foreign exchange fluctuations in our non-U.S. dollar functional currencies. We recorded foreign currency transaction losses of $2.8 million and $0.8 million, respectively, in the comparable year-over-year periods. Also included in net other expense for the six-month period ended June 30, 2015 were losses of $3.4 million related to our foreign currency exchange contracts. Of those losses, $3.2 million was related to ineffectiveness associated with our foreign currency hedges with respect to the Grand Canyon III charter payments and $0.2 million was related to the contract settlement amounts in excess of the ineffectiveness that was recorded for our Grand Canyon II hedges at the end of 2014.

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Other Income – Oil and Gas. Our other income – oil and gas decreased by $10.0 million for the six-month period ended June 30, 2015 as compared to the same period in 2014. The decrease was primarily attributable to a $7.2 million insurance reimbursement in the first quarter of 2014 related to asset retirement work previously performed as well as the decrease in our overriding royalty interests. The reduction in the overriding royalty income is significantly affected by the decline in oil prices since the first quarter of 2014 as well as the shut-in of the Phoenix field for the majority of March 2015 as previously discussed.

Income Tax Provision. Income taxes reflected expenses of $1.0 million for the six-month period ended June 30, 2015 as compared to $37.9 million for the same period last year. The variance primarily reflected decreased profitability in the current year period. The effective tax rate of 5.7% for the six-month period ended June 30, 2015 was lower than the 25.3% effective tax rate for the same period in 2014 as a result of the earnings mix between our higher and lower tax rate jurisdictions.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity (in thousands):

	June 30, 2015	December 31, 2014
Net working capital	$495,946	$468,660
Long-term debt (1)	$722,515	$523,228
Liquidity (2)	$950,168	$1,060,092

(1) Long-term debt does not include the current maturities portion of our long-term debt as that amount is included in net working capital. It is also net of unamortized debt discount on the 2032 Notes. See Note 6 for information relating to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by letters of credit drawn against the facility. Our liquidity at June 30, 2015 included cash and cash equivalents of $500.1 million and $450.1 million of available borrowing capacity under our Revolving Credit Facility (Note 6). Our liquidity at December 31, 2014 included cash and cash equivalents of $476.5 million and $583.6 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our long-term debt, including current maturities, is as follows (in thousands):

	June 30, 2015	December 31, 2014
Term Loan (matures June 2018)	$270,000	$277,500
Nordea Term Loan (matures April 2020)	250,000	—
MARAD Debt (matures February 2027)	92,004	94,792
2032 Notes (mature March 2032) (1)	182,008	179,080
Total debt	$794,012	$551,372

(1) These amounts are net of the unamortized debt discount of $18.0 million at June 30, 2015 and $20.9 million at December 31, 2014. The 2032 Notes will increase to their $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the first date on which the holders of the notes may require us to

repurchase the notes.

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The following table provides summary data from our condensed consolidated statements of cash flows (in thousands):

	Six Months Ended June 30,	
	2015	2014
Cash provided by (used in):		
Operating activities	$3,033	$139,505
Investing activities	$(221,530)	$(97,163)
Financing activities	$239,721	$(15,512)

Our current requirements for cash primarily reflect the need to fund capital expenditures for our current lines of business and to service our debt. Historically, we have funded our capital program with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

As a further response to the recent announcements regarding industry-wide reductions in capital spending, we remain even more focused on maintaining a strong balance sheet and adequate liquidity. Over the near term, we may seek to reduce, defer or cancel certain planned capital expenditures. We believe that internally generated cash flows, available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next 12 months.

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD Debt and our Nordea Credit Agreement indebtedness) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of June 30, 2015 and December 31, 2014, we were in compliance with all of our debt covenants.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Furthermore, during any period of sustained weak economic activity and reduced EBITDA, our ability to access the full available commitment of $600 million under our Revolving Credit Facility may be impacted. At June 30, 2015, our available borrowing capacity under our Revolving Credit Facility totaled $450.1 million, net of $16.7 million of letters of credit issued. We anticipate that our borrowing capacity under the Revolving Credit Facility will continue to decrease over the remainder of 2015. However, for the remainder of 2015, we have no plans or forecasted requirements to borrow under our Revolving Credit Facility other than for issuances of letters of credit. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, such failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

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Subject to the terms of the Credit Agreement, we may borrow and/or obtain letters of credit up to $600 million under our Revolving Credit Facility. Subject to lender participation, we may request that aggregate commitments with respect to the Revolving Credit Facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 6 for additional information relating to our long-term debt, including more information regarding our Credit Agreement, including covenants and collateral.

The 2032 Notes can be converted to our common stock prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our condensed consolidated balance sheet. No conversion triggers were met during the six-month periods ended June 30, 2015 and 2014.

Operating Cash Flows

Total cash flows from operating activities decreased by $136.5 million for the six-month period ended June 30, 2015 as compared to the same period in 2014. This decrease primarily reflected decreases in income from operations and changes in working capital.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, improvements and modifications to existing assets, and investments in our production facilities. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Six Months Ended June 30,	
	2015	2014
Capital expenditures:		
Well Intervention	$(222,968)	$(65,540)
Robotics	(8,981)	(27,511)
Production Facilities	(823)	(116)
Other	(100)	166
Distributions from equity investments, net (1)	3,842	4,849
Proceeds from sale of assets (2)	7,500	11,074
Acquisition of noncontrolling interests (3)	—	(20,085)
Net cash used in investing activities	$(221,530)	$(97,163)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the six-month periods ended June 30, 2015 and 2014 were $3.5 million and $5.1 million, respectively (Note 5).

(2) Primarily reflects cash received from the sale of our Ingleside spoolbase in January 2014.

(3) Relates to the acquisition in February 2014 of our former minority partner’s noncontrolling interests in the entity that owns the HP I.

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Capital expenditures associated with our business have primarily included payments associated with the construction of our Q5000 and Q7000 vessels (see below), payments in connection with the Seawell refit activities in 2015 and the upgrades and modifications of the Helix 534 in 2014, the investment in the topside well intervention equipment for the two newbuild monohull vessels that we expect to charter to perform our agreements with Petrobras (see below), and the acquisition of additional ROVs and trenchers for our robotics business.

In March 2012, we entered into a contract with a shipyard in Singapore for the construction of the Q5000. This $386.5 million shipyard contract represented the majority of the costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments were made as a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At June 30, 2015, our total investment in the Q5000 was $479.0 million, including $386.5 million of scheduled payments made to the shipyard. The vessel was delivered in the second quarter of 2015 and is currently in transit to the Gulf of Mexico. The Q5000 will commence its five-year charter contract with BP on April 1, 2016 but may work for other industry participants prior to that date. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects (Note 6). The Nordea Term Loan was funded at the time of the delivery of the Q5000.

In September 2013, we executed a second contract with the same shipyard in Singapore that constructed the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which is to be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the current terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% was to be paid upon the delivery of the vessel. In June 2015, we entered into an amendment with the shipyard to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017. Pursuant to this amendment, the remaining 80% will now be paid in two installments, with 20% in June 2016 and 60% upon the delivery of the vessel. We agreed to pay the shipyard incremental costs of up to $14.5 million. At June 30, 2015, our total investment in the Q7000 was $105.8 million, including $69.2 million paid to the shipyard upon signing the contract. We plan to incur approximately $14 million of costs related to the construction of the Q7000 over the remainder of 2015.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. Our total investment in the topside equipment for both vessels is expected to be approximately $260 million. We have invested $85.7 million as of June 30, 2015 and plan to invest approximately $20 million in the topside equipment over the remainder of 2015.

Outlook

We anticipate that our capital expenditures for fiscal year 2015 will total approximately $365 million. This estimate may change based on various economic factors and/or the existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given a prolonged economic downturn. We believe that our cash on hand, internally generated cash flows, and availability under our credit facility will provide the capital necessary to continue funding our 2015 initiatives.

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of June 30, 2015 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2032 Notes (2)	$200,000	$—	$—	$—	$200,000
Term Loan (3)	270,000	30,000	60,000	180,000	—
Nordea Term Loan	250,000	35,714	71,429	142,857	—
MARAD debt	92,004	5,783	12,447	13,720	60,054
Interest related to debt (4)	200,213	31,451	54,663	27,527	86,572
Property and equipment (5)	377,677	82,623	295,054	—	—
Operating leases (6)	974,746	151,845	314,497	249,143	259,261
Total cash obligations	$2,364,640	$337,416	$808,090	$613,247	$605,887

(1) Excludes unsecured letters of credit outstanding at June 30, 2015 totaling $16.7 million. These letters of credit support various obligations, such as contractual obligations, customs duties, contract bidding and insurance activities.

(2) Notes mature in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of our common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of their issuance price on that 30th trading day (i.e., $32.53 per share). At June 30, 2015, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 6 for additional information.

(3) Amount reflects borrowings made in July 2013. The Term Loan will mature on June 19, 2018.

(4) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at June 30, 2015 for variable rate debt.

(5) Primarily reflects the costs associated with our well intervention assets currently under construction, including our new semi-submersible well intervention vessel, the Q7000, and the topside equipment for the two newbuild monohull vessels that we plan to charter (Note 12).

(6) Operating leases include vessel charters and facility leases. At June 30, 2015, our vessel charter commitments totaled approximately $933.6 million, including three vessels that will not be delivered to us until 2016. The less than one year amount includes approximately $3.7 million of additional commitments to extend the delivery of the Grand Canyon III until February 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements. We prepare these financial statements and related footnotes in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. For additional information regarding our critical accounting policies and estimates, please read our “Critical Accounting Policies and Estimates” as disclosed in our 2014 Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of June 30, 2015, $520.0 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, thereby increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013, we entered into various interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. Additionally in June 2015, we entered into various interest rate swap contracts to fix the interest rate on $187.5 million of our Nordea Term Loan debt. These swap contracts, which are settled monthly, began in June 2015 and extend through April 2020. The impact of interest rate risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $1.0 million in interest expense for the six-month period ended June 30, 2015.

Foreign Currency Exchange Rate Risk. Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to our North Sea operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies and a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the six-month period ended June 30, 2015, we recognized losses of $2.8 million related to foreign currency transactions in “Other expense, net” in our condensed consolidated statement of operations.

We entered into various foreign currency exchange contracts to stabilize expected cash outflows related to certain vessel charters denominated in Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. For the six-month period ended June 30, 2015, we recorded losses totaling $3.4 million as a component of “Other expense, net” in our condensed consolidated statement of operations. Of those losses, $3.2 million was related to ineffectiveness associated with our foreign currency hedges with respect to the Grand Canyon III charter payments and $0.2 million was related to the contract settlement amounts in excess of the ineffectiveness that was recorded for our Grand Canyon II hedges at the end of 2014.

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Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as of June 30, 2015. Based on this evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2015 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms; and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 12 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased [(1)]	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum number of shares that may yet be purchased under the program [(2)]
April 1 to April 30, 2015	—	$—	—	432,182
May 1 to May 31, 2015	1,814	16.76	—	518,743
June 1 to June 30, 2015	—	—	—	518,743
	1,814	$16.76	—	

(1) Includes shares delivered to the Company by employees in satisfaction of minimum withholding taxes upon vesting of restricted shares.

(2) Under the terms of our stock repurchase program, the issuance of shares to members of our Board of Directors and to certain employees, including shares issued to our employees under the ESPP (Note 10), increases the amount of shares available for repurchase. For additional information regarding our stock repurchase program, see Note 10 to our 2014 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index on Page 46 hereof.

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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.

		HELIX ENERGY SOLUTIONS GROUP, INC. (Registrant)
Date: July 22, 2015	By:	/s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: July 22, 2015	By:	/s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of Helix.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Amendment No. 1 to Credit Agreement dated as of May 13, 2015, by and among Helix Energy Solutions Group, Inc. and Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on May 14, 2015 (001-32936)
10.1	Amendment No. 1, dated as of June 8, 2015, to Construction Contract between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on June 11, 2015 (001-32936)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith