

Rosetta Resources Inc.
Form 10-Q
May 05, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
For The Quarterly Period Ended March 31, 2014**

OR

.. **Transition Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission File Number: 000-51801**

ROSETTA RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of	43-2083519 (I.R.S. Employer
incorporation or organization)	Identification No.)
1111 Bagby Street, Suite 1600	
Houston, TX (Address of principal executive offices)	77002 (Zip Code)
(713) 335-4000	
(Registrant's telephone number, including area code)	

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 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). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input type="checkbox"/>

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

The number of shares of the registrant's Common Stock, \$0.001 par value per share, outstanding as of April 25, 2014 was 61,436,417 which excludes unvested restricted stock awards.

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Table of Contents**PART I. FINANCIAL INFORMATION****Item 1. Financial Statements****Rosetta Resources Inc.****Consolidated Balance Sheet****(In thousands, except par value and share amounts)**

	March 31, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	\$ 55,115	\$ 193,784
Accounts receivable	130,302	122,677
Derivative instruments	37	4,307
Prepaid expenses	7,932	9,860
Deferred income taxes	18,963	27,976
Other current assets	2,164	1,284
Total current assets	214,513	359,888
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	4,387,172	3,951,397
Unproved/unevaluated properties, not subject to amortization	727,051	755,438
Gathering systems and compressor stations	204,944	168,730
Other fixed assets	27,299	26,362
	5,346,466	4,901,927
Accumulated depreciation, depletion and amortization, including impairment	(2,094,737)	(2,020,879)
Total property and equipment, net	3,251,729	2,881,048
Other assets:		
Debt issuance costs	24,590	25,602
Derivative instruments	2,710	5,458
Other long-term assets	327	4,622
Total other assets	27,627	35,682
Total assets	\$ 3,493,869	\$ 3,276,618
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 286,397	\$ 190,950

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Royalties and other payables	83,542	78,264
Derivative instruments	13,738	4,913
Total current liabilities	383,677	274,127
Long-term liabilities:		
Derivative instruments	438	433
Long-term debt	1,560,000	1,500,000
Deferred income taxes	145,998	136,407
Other long-term liabilities	18,744	17,317
Total liabilities	2,108,857	1,928,284
Commitments and Contingencies (Note 9)		
Stockholders' equity:		
Preferred stock, \$0.001 par value; authorized 5,000,000 shares; no shares issued in 2014 or 2013		
Common stock, \$0.001 par value; authorized 150,000,000 shares; issued 62,200,386 shares and 62,032,162 shares at March 31, 2014 and December 31, 2013, respectively		
	62	61
Additional paid-in capital	1,186,236	1,182,672
Treasury stock, at cost; 773,061 shares and 724,755 shares at March 31, 2014 and December 31, 2013, respectively	(26,725)	(24,592)
Accumulated other comprehensive loss	(105)	(108)
Retained earnings	225,544	190,301
Total stockholders' equity	1,385,012	1,348,334
Total liabilities and stockholders' equity	\$ 3,493,869	\$ 3,276,618

See accompanying notes to the consolidated financial statements.

Table of Contents**Rosetta Resources Inc.****Consolidated Statement of Operations****(In thousands, except per share amounts)****(Unaudited)**

	Three Months Ended March 31,	
	2014	2013
Revenues:		
Oil sales	\$ 131,677	\$ 110,052
NGL sales	55,295	46,461
Natural gas sales	51,379	33,576
Derivative instruments	(23,785)	(11,969)
Total revenues	214,566	178,120
Operating costs and expenses:		
Lease operating expense	19,521	8,911
Treating and transportation	20,677	15,087
Taxes, other than income	10,206	7,655
Depreciation, depletion and amortization	74,775	44,630
General and administrative costs	19,538	15,532
Total operating costs and expenses	144,717	91,815
Operating income	69,849	86,305
Other expense (income):		
Interest expense, net of interest capitalized	15,290	6,069
Interest income	(12)	
Other expense (income), net	151	(30)
Total other expense	15,429	6,039
Income before provision for income taxes	54,420	80,266
Income tax expense	19,177	26,786
Net income	\$ 35,243	\$ 53,480
Earnings per share:		
Basic	\$ 0.57	\$ 1.01
Diluted	\$ 0.57	\$ 1.01
Weighted average shares outstanding:		
Basic	61,380	52,733

Diluted

61,547

53,081

See accompanying notes to the consolidated financial statements.

Table of Contents**Rosetta Resources Inc.****Consolidated Statement of Comprehensive Income****(In thousands)****(Unaudited)**

	Three Months Ended March 31,	
	2014	2013
Net income	\$ 35,243	\$ 53,480
Other comprehensive income:		
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of (\$154) for the three months ended March 31, 2013		271
Postretirement medical benefits prior service benefit (cost), net of income taxes of (\$2) and \$104, respectively	3	(185)
Other comprehensive income	3	86
Comprehensive income	\$ 35,246	\$ 53,566

See accompanying notes to the consolidated financial statements.

Table of Contents**Rosetta Resources Inc.****Consolidated Statement of Cash Flows****(In thousands)****(Unaudited)**

	Three Months Ended March 31,	
	2014	2013
Cash flows from operating activities:		
Net income	\$ 35,243	\$ 53,480
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	74,775	44,630
Deferred income taxes	18,604	26,060
Amortization of deferred loan fees recorded as interest expense	984	538
Stock-based compensation expense	3,358	2,664
Loss (gain) due to change in fair value of derivative instruments	15,848	13,971
Change in operating assets and liabilities:		
Accounts receivable	(7,625)	(2,955)
Prepaid expenses	1,956	771
Other current assets	(880)	
Long-term assets	43	(1)
Accounts payable and accrued liabilities	3,264	(729)
Royalties and other payables	5,277	4,476
Other long-term liabilities	377	(1,266)
Net cash provided by operating activities	151,224	141,639
Cash flows from investing activities:		
Deposit on Permian acquisition		(38,400)
Acquisitions of oil and gas assets	(79,015)	
Additions to oil and gas assets	(268,836)	(175,849)
Disposals of oil and gas assets	8	(2,651)
Net cash used in investing activities	(347,843)	(216,900)
Cash flows from financing activities:		
Borrowings on Credit Facility	80,000	140,000
Payments on Credit Facility	(20,000)	(85,000)
Proceeds from stock options exercised	61	408
Purchases of treasury stock	(2,133)	(6,256)
Excess tax benefit from share-based awards	22	
Net cash provided by financing activities	57,950	49,152

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Net decrease in cash	(138,669)	(26,109)
Cash and cash equivalents, beginning of period	193,784	36,786
Cash and cash equivalents, end of period	\$ 55,115	\$ 10,677
Supplemental disclosures:		
Capital expenditures included in Accounts payable and accrued liabilities	\$ 206,867	\$ 77,867

See accompanying notes to the consolidated financial statements.

Table of Contents**Rosetta Resources Inc.****Consolidated Statement of Stockholders' Equity****(In thousands, except share amounts)****(Unaudited)**

	Common Stock		Additional	Treasury Stock		Accumulated	Other	Retained	Total
	Shares	Amount	Paid-In	Shares	Amount	Comprehensive	Income	Earnings	Stockholders
			Capital			(Loss)/			Equity
Balance at December 31, 2013	62,032,162	\$ 61	\$ 1,182,672	724,755	\$ (24,592)	\$ (108)		\$ 190,301	\$ 1,348,334
Excess tax benefit from share-based awards			22						22
Stock options exercised	2,500	1	61						62
Treasury stock employee tax payment				48,306	(2,133)				(2,133)
Stock-based compensation			3,481						3,481
Vesting of restricted stock	165,724								
Comprehensive income							3	35,243	35,246
Balance at March 31, 2014	62,200,386	\$ 62	\$ 1,186,236	773,061	\$ (26,725)	\$ (105)		\$ 225,544	\$ 1,385,012

See accompanying notes to the consolidated financial statements.

Table of Contents**Rosetta Resources Inc.****Notes to Consolidated Financial Statements (unaudited)****(1) Organization and Operations of the Company**

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company's operations are located in the Eagle Ford shale in South Texas and the Permian Basin in West Texas.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. (GAAP). These financial statements and notes should be read in conjunction with the Company's audited Consolidated Financial Statements and the notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2013 (2013 Annual Report).

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2013 Annual Report. There have been no changes to the Company's significant accounting policies since December 31, 2013.

Recent Accounting Developments

There have been no recently issued accounting developments that have been applied or may impact the Company in future periods.

(3) Property and Equipment

The Company's Total property and equipment, net consists of the following:

	March 31, 2014	December 31, 2013
	(In thousands)	
Proved properties	\$ 4,387,172	\$ 3,951,397
Unproved/unevaluated properties	727,051	755,438
Gathering systems and compressor stations	204,944	168,730
Other fixed assets	27,299	26,362
Total	5,346,466	4,901,927
Less: Accumulated depreciation, depletion and amortization	(2,094,737)	(2,020,879)

Total property and equipment, net	\$ 3,251,729	\$ 2,881,048
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Acquisitions

2014 Permian Acquisition. On December 30, 2013, the Company entered into a definitive agreement with several private parties to acquire Delaware Basin assets covering 5,034 net acres located in Reeves County (the "2014 Permian Acquisition"). These assets include 13 gross producing wells, of which 11 are operated by the Company. The Company completed the 2014 Permian Acquisition on February 28, 2014, with an effective date of December 1, 2013, for total cash consideration of \$83.2 million, subject to further customary post-closing adjustments.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells along with a third party's option to participate in future wells in certain leases of its Gates Ranch leasehold located in the Eagle Ford shale (the "Gates Acquisition") in Webb County for total cash consideration of approximately \$128.1 million. The transaction closed on June 5, 2013 (the "Gates Acquisition Date") and was financed with borrowings under the Company's senior secured revolving credit facility (the "Credit Facility"), as described in Note 7 "Debt and Credit Agreements." As of the Gates Acquisition Date, the Company owns a 100% working interest in the entire Gates Ranch leasehold.

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2013 Permian Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP to purchase producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas (the 2013 Permian Acquisition). The Company completed the 2013 Permian Acquisition on May 14, 2013, with an effective date of January 1, 2013, for total cash consideration of \$825.2 million. The 2013 Permian Acquisition was financed with the proceeds from the Company's issuance of the 5.625% Senior Notes, as described in Note 7 Debt and Credit Agreements, and the common stock offering described in Note 10 Equity. In connection with the 2013 Permian Acquisition and related financings, the Company incurred total transaction costs of approximately \$31.0 million, including (i) \$5.6 million of commitment fees and related expenses associated with a bridge credit facility (Bridge Credit Facility), which were recorded as Interest expense since the Company did not borrow under the Bridge Credit Facility, (ii) \$10.0 million of debt issuance costs paid in connection with the issuance of the 5.625% Senior Notes, which were deferred and are being amortized over the term of these senior notes, (iii) \$13.1 million of equity issuance costs and related expenses associated with the common stock offering, which were reflected as a reduction of equity proceeds, and (iv) \$2.3 million of consulting, investment, advisory, legal and other acquisition-related fees, which were expensed and are included in General and administrative costs.

The above transactions were accounted for under the acquisition method of accounting, whereby each respective purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (or shortfall of purchase price versus net fair value recorded as bargain purchase). Based on the final purchase price allocations for the Gates Acquisition and the 2013 Permian Acquisition and the preliminary purchase price allocation for the 2014 Permian Acquisition, no goodwill or bargain purchase was recognized. The final purchase price allocation for the 2013 Permian and Gates Ranch Acquisitions and the preliminary purchase price allocation for the 2014 Permian Acquisition, representing consideration paid, assets acquired and liabilities assumed as of the respective acquisition dates, are shown in the tables below.

2013 Permian Acquisition and Gates Ranch Acquisition

	Final Total Purchase Price Allocation	
	(in thousands)	
Cash consideration	\$	953,242
Fair value of assets acquired:		
Other fixed assets	\$	600
Oil and natural gas properties		
Proved properties		290,273
Unproved/unevaluated properties		663,300
Total assets acquired	\$	954,173
Fair value of liabilities assumed:		
Asset retirement obligations	\$	931
Net assets acquired	\$	953,242

2014 Permian Acquisition

	Preliminary Total Purchase Price Allocation	
	(in thousands)	
Cash consideration	\$	83,172
Fair value of assets acquired:		
Oil and natural gas properties		
Proved properties	\$	61,598
Unproved/unevaluated properties		21,867
Total assets acquired	\$	83,465
Fair value of liabilities assumed:		
Asset retirement obligations	\$	293
Net assets acquired	\$	83,172

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change. See Note 5 Fair Value Measurements for additional information.

The results of operations attributable to the 2014 Permian Acquisition were included in the Company's Consolidated Statement of Operations beginning on March 1, 2014 and increased Total revenues and Operating income by \$1.6 million and \$1.1 million, respectively.

The following unaudited pro forma information assumes the transactions and related financings for the 2013 Permian Acquisition and the Gates Acquisition occurred on January 1, 2012 and the transaction for the 2014 Permian Acquisition occurred on January 1, 2013. The unaudited pro forma information includes the effects of issuing the 5.625% Senior Notes, the issuance of common stock in the equity offering and the use of proceeds from the debt and equity offerings as discussed above. The pro forma results of operations have been prepared by adjusting the Company's historical results to include the historical results of the acquired assets based on information provided by the seller, the Company's knowledge of the acquired properties and the impact of the Company's purchase price allocation. The Company believes the assumptions used provide a reasonable basis for reflecting the pro forma significant effects directly attributable to the acquisitions and associated financings. The pro forma results of operations do not include any cost savings or other synergies that may result from the 2014 Permian Acquisition and the 2013 Permian Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the Delaware or Permian assets. The pro forma information does not purport to represent what the Company's results of operations would have been if the 2013 Permian Acquisition and Gates Acquisition had occurred on January 1, 2012 and the 2014 Permian Acquisition had occurred on January 1, 2013.

	Three Months Ended March 31,	
	2014 (1)	2013
	(In thousands, except per share and share data)	
Total revenues	\$ 218,306	\$ 202,914
Net income	36,147	51,860
Earnings per share:		
Basic	\$ 0.59	\$ 0.85
Diluted	\$ 0.59	\$ 0.85
Weighted average shares outstanding:		
Basic	61,380	60,783
Diluted	61,547	61,131

- (1) No pro forma adjustments were made related to the 2013 Permian Acquisition and Gates Acquisition for the period as the acquisitions and related financings are included in the Company's historical results.

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Additional Disclosures about Property and Equipment

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized \$1.6 million and \$2.1 million of internal costs for the three months ended March 31, 2014 and 2013, respectively.

Oil and gas properties include unevaluated property costs of \$727.1 million and \$755.4 million as of March 31, 2014 and December 31, 2013, respectively, which are not being amortized. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest. Such costs are periodically evaluated for impairment, and upon evaluation or impairment are transferred to the Company's full cost pool and amortized.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company's costs are included in one cost center because all of the Company's operations are located in the United States. The Company's ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of March 31, 2014, which were based on a West Texas Intermediate oil price of \$94.92 per Bbl and a Henry Hub natural gas price of \$3.99 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and natural gas properties as of March 31, 2014, and as a result, no write-down was recorded. It is possible that a write-down of the Company's oil and gas properties could occur in future periods in the event that oil and natural gas prices significantly decline or the Company experiences significant downward adjustments to its estimated proved reserves.

(4) Commodity Derivative Contracts

The Company is exposed to various market risks, including volatility in oil, natural gas liquids (NGL) and natural gas prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company's oil, NGL and natural gas production.

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As of March 31, 2014, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2014	Costless Collar	3,000	825,000	\$ 83.33	\$ 109.63
Crude oil	2014	Swap	6,000	1,650,000	93.13	
Crude oil	2015	Swap	10,000	3,650,000	88.58	
Crude oil	2016	Swap	1,000	366,000	84.40	
				6,491,000		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2014	Swap	4,500	1,237,500	\$ 13.21
NGL-Propane	2014	Swap	2,785	765,875	44.71
NGL-Isobutane	2014	Swap	930	255,750	61.26
NGL-Normal Butane	2014	Swap	875	240,625	60.29
NGL-Pentanes Plus	2014	Swap	910	250,250	84.97
NGL-Ethane	2015	Swap	2,500	912,500	11.59
NGL-Propane	2015	Swap	1,250	456,250	43.26
NGL-Isobutane	2015	Swap	450	164,250	53.76
NGL-Normal Butane	2015	Swap	400	146,000	53.76
NGL-Pentanes Plus	2015	Swap	400	146,000	76.44
				4,575,000	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (MMBtu)	Total Notional Volume (MMBtu)	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2014	Costless Collar	50,000	13,750,000	3.60	4.94
Natural gas	2015	Costless Collar	50,000	18,250,000	3.60	5.04
Natural gas	2014	Swap	30,000	8,250,000	4.07	
Natural gas	2015	Swap	40,000	14,600,000	4.18	
Natural gas	2016	Swap	20,000	7,320,000	4.02	
				62,170,000		

As of March 31, 2014, the Company's derivative instruments were with counterparties who are lenders under its Credit Facility. This practice allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit Facility, thus eliminating the need for independent collateral postings. The Company's ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Items 1 and 2. Business and Properties Government Regulation in the Company's 2013 Annual Report. As of March 31, 2014, the Company had no deposits for collateral regarding commodity derivative positions.

Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company elected to de-designate all commodity contracts previously designated as cash flow hedges as of December 31, 2011 and discontinue hedge accounting prospectively. As of December 31, 2013, all frozen mark-to-market values included in Accumulated other comprehensive income were reclassified into earnings. With the election to de-designate hedging instruments, all of the Company's derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in Accumulated other comprehensive income. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but such adjustments had no cash flow impact in the current period. The cash flow impact occurs upon settlement of the underlying contract.

Table of Contents**Additional Disclosures about Derivative Instruments**

Authoritative derivative guidance requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company's financial statements. The following table sets forth information on the location and amounts of the Company's derivative instrument fair values in the Consolidated Balance Sheet as of March 31, 2014 and December 31, 2013, respectively:

Commodity derivative contracts	Location on Consolidated Balance Sheet	Asset (Liability) Fair Value	
		March 31, 2014	December 31, 2013
		(In thousands)	
Oil	Derivative instruments current assets	\$ 1,299	\$ 1,299
Oil	Derivative instruments non-current assets	1,055	2,117
Oil	Derivative instruments current liabilities	(10,837)	(5,629)
Oil	Derivative instruments non-current liabilities	(2,159)	
NGL	Derivative instruments current assets	37	2,834
NGL	Derivative instruments non-current assets	274	(129)
NGL	Derivative instruments current liabilities	2,909	461
NGL	Derivative instruments non-current liabilities	299	(433)
Natural gas	Derivative instruments current assets		174
Natural gas	Derivative instruments non-current assets	1,381	3,470
Natural gas	Derivative instruments current liabilities	(5,810)	255
Natural gas	Derivative instruments non-current liabilities	1,422	
Total derivative fair value, net, not designated as hedging instruments		\$ (11,429)	\$ 4,419

The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the three months ended March 31, 2014 and 2013, respectively:

Location on Consolidated Statement of Operations	Description of (Loss) Gain	Three Months Ended March 31,	
		2014	2013
		(In thousands)	
Derivative instruments	(Loss) gain recognized in income	(7,937)	2,002
	Realized (loss) gain recognized in income	\$ (7,937)	\$ 2,002
Derivative instruments	Loss recognized in income due to changes in fair value	\$ (15,848)	\$ (13,546)
Derivative instruments	Loss reclassified from Accumulated OCI		(425)
	Unrealized loss recognized in income	\$ (15,848)	\$ (13,971)

Total commodity derivative loss recognized in income	\$ (23,785)	\$ (11,969)
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(5) Fair Value Measurements

The Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. See Note 3 Property and Equipment for more information on the Company's fair value measurement of non-recurring assets and liabilities related to the 2014 Permian Acquisition.

As defined in the guidance of the Financial Accounting Standards Board (FASB), fair value is the amount 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 (an exit price). To estimate fair value, the Company utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The FASB's guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

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Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis for the respective period:

	Fair value as of March 31, 2014				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(In thousands)				
Assets:					
Money market funds	\$	\$ 1,035	\$	\$	\$ 1,035
Commodity derivative contracts			13,992	(11,245)	2,747
Liabilities:					
Commodity derivative contracts			(25,421)	11,245	(14,176)
Total fair value	\$	\$ 1,035	\$ (11,429)	\$	\$ (10,394)

	Fair value as of December 31, 2013				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(In thousands)				
Assets:					
Money market funds	\$	\$ 1,035	\$	\$	\$ 1,035
Commodity derivative contracts			21,675	(11,910)	9,765
Liabilities:					
Commodity derivative contracts			(17,256)	11,910	(5,346)
Total fair value	\$	\$ 1,035	\$ 4,419	\$	\$ 5,454

- (1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle. No margin or collateral balances are deposited with counterparties and as such, gross amounts are offset to determine the net amounts presented in the Consolidated

Balance Sheet.

The Company's Level 3 instruments include commodity derivative contracts for which fair value is determined by a third-party provider. Although the Company compares the fair values derived from the third-party provider with its counterparties, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its third-party provider or counterparties. Therefore, these commodity derivative contracts are classified as Level 3 instruments.

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The following table presents a range of the unobservable inputs provided by the Company's third-party provider utilized in the fair value measurements of the Company's assets and liabilities classified as Level 3 instruments as of March 31, 2014 (in thousands):

3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range		Weighted Average
				Minimum	Maximum	
swaps	\$ (12,050)	Discounted cash flow	Forward price curve-swaps	\$ 82.94	\$ 101.36	\$ 9
costless collars	110	Option model	Forward price curve- costless collar option value	(1.45)	2.28	0
swaps	5,263	Discounted cash flow	Forward price curve-swaps	0.27	1.31	0
swaps	(1,744)	Discounted cash flow				
t of exchange						
changes on cash (2,481)	(1,059)					
cash equivalents						
decrease in cash (12,086)	(7,556)					
cash equivalents						
and cash						
alents:						
ce, beginning	494,192	476,492				
ce, end of	\$482,106	\$468,936				

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

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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 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 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 (“U.S. GAAP”).

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. GAAP and are consistent in all material respects with those applied in our 2015 Annual Report on Form 10-K (“2015 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. 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. The operating results for the three- and nine-month periods ended September 30, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016. Our balance sheet as of December 31, 2015 included herein has been derived from the audited balance sheet as of December 31, 2015 included in our 2015 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 2015 Form 10-K.

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 August 2015, the FASB issued ASU No. 2015-14 to defer the effective date of ASU No. 2014-09 by one year to annual reporting periods beginning after December 15, 2017. Adoption as of the original effective date is permitted. In March 2016, the FASB issued ASU No. 2016-08, which amends the guidance to clarify the implementation guidance on principal versus agent considerations (gross versus net revenue presentation). In April 2016, the FASB issued ASU No. 2016-10, which amends the guidance with respect to certain implementation issues on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-12, which provides certain narrow-scope improvements and practical expedients to the guidance. The new revenue standard 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 our existing revenue recognition policies to determine the types of contracts that are within the scope of this guidance and the impact the adoption of this standard may have on our consolidated financial statements. We have not yet determined if we will apply the full retrospective or the modified retrospective method.

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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. In August 2015, the FASB issued ASU No. 2015-15, “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.” This ASU includes an SEC staff announcement that the SEC staff will not object to an entity presenting the cost of securing a revolving line of credit as an asset, regardless of whether a balance is outstanding. The subject of this ASU was not previously addressed by ASU No. 2015-03. We adopted this guidance retrospectively in the first quarter of 2016. As a result, we presented \$12.0 million of unamortized debt issuance costs that had been included in “Other assets, net” in our consolidated balance sheet as of December 31, 2015 as direct deductions from the carrying amounts of the related debt liabilities.

In November 2015, the FASB issued ASU No. 2015-17, “Balance Sheet Classification of Deferred Taxes.” This ASU requires companies to classify all deferred tax assets and liabilities as non-current on the balance sheet instead of separating deferred taxes into current and non-current amounts. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by this guidance. The guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. This guidance will not affect our statements of operations or statements of cash flows.

In February 2016, the FASB issued ASU No. 2016-02, “Leases (Topic 842).” This ASU amends the existing accounting standards for leases. The amendments are intended to increase transparency and comparability among organizations by requiring recognition of lease assets and lease liabilities on the balance sheet and disclosure of key information about leasing arrangements. The guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods. Early adoption is permitted. The guidance is required to be adopted at the earliest period presented using a modified retrospective approach. We are currently evaluating the impact these amendments will have on our consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, “Improvements to Employee Share-Based Payment Accounting.” This ASU simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities, and classification in the statement of cash flows. The guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is permitted. An entity that elects early adoption of the amendment under this ASU must adopt all aspects of the amendment in the same period. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, “Measurement of Credit Losses on Financial Instruments.” This ASU replaces the current incurred loss model for measurement of credit losses on financial assets including trade receivables with a forward-looking expected loss model based on historical experience, current conditions and reasonable and supportable forecasts. The guidance is effective for annual reporting periods beginning after December 15, 2019, including interim periods. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15, “Classification of Certain Cash Receipts and Cash Payments.” This ASU addresses how certain cash receipts and cash payments are presented and classified in the statement of cash flows with the objective of reducing the existing diversity in practice. The guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods. Early adoption is permitted. An entity that elects early adoption of the amendment under this ASU must adopt all aspects of the amendment in the same period. We do not expect this guidance to have a material impact on our statements of cash flows.

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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 maximizing production economics. We provide services primarily in deepwater in the U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding 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 U.S. Gulf of Mexico and North Sea regions. Our Well Intervention segment also includes intervention riser systems (“IRSs”), some of which we rent out on a stand-alone basis, and subsea intervention lubricators (“SILs”). Our well intervention vessels include the Q4000, the Q5000, the Well Enhancer, the Seawell, the Helix 534 and the Skandi Constructor, which is a chartered vessel. The Q5000 vessel went on contracted rates on May 19, 2016 under our five-year contract with BP; we have been notified by BP that they will not take more than the minimum 270 contracted days in 2017. We currently have another semi-submersible well intervention vessel under construction, the Q7000. We are chartering the Siem Helix 1 and have contracted to charter the Siem Helix 2. These two newbuild monohull vessels are to be 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 three chartered ROV support vessels following the expiration of the Rem Installer charter on July 12, 2016. Another chartered ROV support vessel, the Grand Canyon III, was delivered by the shipyard to the vessel owner in May 2016. The vessel is currently stacked by the owner and is expected to be in service for us in May 2017.

Our Production Facilities segment includes the Helix Producer I vessel (“HP I”), a ship-shaped dynamic positioning floating production unit, and 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. The HP I was previously contracted to process production from the Phoenix field until at least December 31, 2017, and in July 2016 we entered into a new fixed fee agreement for the HP I with the same operator, effective June 1, 2016, for service to the Phoenix field until at least June 1, 2023. The Production Facilities segment also includes our ownership interest in Independence Hub, LLC (“Independence Hub”) and included our former ownership interest in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) that we sold for \$25 million in February 2016 (Note 5).

In January 2016, we sold our office and warehouse property located in Aberdeen, Scotland for approximately \$11 million and entered into a separate agreement with the same party to lease back the facility for a minimum lease term of 15 years with two five-year options to extend the lease at our option. A gain of approximately \$7.6 million from the sale of this property is deferred and will be amortized over the 15-year minimum lease term.

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Note 3 — Details of Certain Accounts

Other current assets consist of the following (in thousands):

	September 30, 2016	December 31, 2015
Note receivable ⁽¹⁾	\$ 10,000	\$ 10,000
Other receivables	5,288	—
Prepaid insurance	6,462	5,433
Other prepaids	9,898	10,142
Deferred costs	8,891	609
Spare parts inventory	4,401	4,985
Value added tax receivable	8,995	7,842
Other	129	507
Total other current assets	\$ 54,064	\$ 39,518

Relates to the balance of the promissory note we received in connection with the sale of our former Ingleside (1) 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 \$10 million principal balance is required to be paid on December 31, 2016.

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

	September 30, 2016	December 31, 2015
Note receivable, net ⁽¹⁾	\$ 4,330	\$ —
Deferred dry dock costs, net	13,854	19,615
Deferred costs	21,829	—
Deferred financing costs, net ⁽²⁾	4,238	7,863
Charter fee deposit (Note 12)	12,544	12,544
Other	1,150	1,586
Total other assets, net	\$ 57,945	\$ 41,608

(1) Amount, net of allowance of \$2.7 million, relates to an agreement we entered into with one of our customers to defer their payment obligations until June 30, 2018. Interest at a rate of 3% per annum is payable semi-annually.

(2) Represents unamortized debt issuance costs related to our Revolving Credit Facility (Note 6).

Accrued liabilities consist of the following (in thousands):

	September 30, 2016	December 31, 2015
Accrued payroll and related benefits	\$ 20,660	\$ 14,775
Deferred revenue	12,789	12,841
Accrued interest	969	4,854
Derivative liability (Note 14)	17,721	23,192
Taxes payable excluding income tax payable	9,018	8,136
Other	8,747	7,843
Total accrued liabilities	\$ 69,904	\$ 71,641

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Other non-current liabilities consist of the following (in thousands):

	September 30, 2016	December 31, 2015
Loss in excess of equity investment (Note 5)	\$ 8,437	\$ 8,308
Deferred gain on sale of property (Note 2)	6,190	—
Deferred revenue	5,926	—
Derivative liability (Note 14)	20,383	39,709
Other	3,489	3,398
Total other non-current liabilities	\$ 44,425	\$ 51,415

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):

	Nine Months Ended September 30, 2016 2015	
Interest paid, net of interest capitalized	\$17,970	\$11,823
Income taxes paid	\$4,674	\$16,008

Our non-cash investing activities include property and equipment capital expenditures that are incurred but not yet paid. These non-cash capital expenditures totaled \$88.0 million as of September 30, 2016 and \$18.7 million as of December 31, 2015. The non-cash capital expenditures as of September 30, 2016 included a \$69.2 million shipyard invoice for the Q7000 that was paid in October 2016 (Note 12).

Note 5 — Equity Investments

We have a 20% ownership interest in Independence Hub, LLC (“Independence Hub”) that we account for using the equity method of accounting. We previously had a 50% ownership interest in Deepwater Gateway, L.L.C., which we sold in February 2016 to a subsidiary of Genesis Energy, L.P., the other owner, for \$25 million with no resulting gain or loss. Both equity investments are included in our Production Facilities segment.

Independence Hub owns the “Independence Hub” platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our share of the losses reported by Independence Hub exceeded the carrying amount of our investment by \$8.4 million as of September 30, 2016 and \$8.3 million at December 31, 2015 reflecting our share of Independence Hub’s obligations (primarily its estimated asset retirement obligations to decommission the platform), net of remaining working capital. This liability is reflected in “Other non-current liabilities” in the accompanying condensed consolidated balance sheets.

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

Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	2015
--	---	------

Deepwater Gateway \$— \$1,200 \$3,900

Independence Hub	—560	—	1,400
Total	\$—\$1,760	\$1,200	\$5,300

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Note 6 — Long-Term Debt

Scheduled maturities of our long-term debt outstanding as of September 30, 2016 are as follows (in thousands):

	Term Loan	2032 Notes ⁽¹⁾	MARAD Debt	Nordea Q5000 Loan	Total
Less than one year	\$28,968	\$—	\$6,222	\$35,715	\$70,905
One to two years	195,532	—	6,532	35,714	237,778
Two to three years	—	—	6,858	35,714	42,572
Three to four years	—	—	7,200	98,214	105,414
Four to five years	—	—	7,560	—	7,560
Over five years	—	185,116	48,850	—	233,966
Total debt	224,500	185,116	83,222	205,357	698,195
Current maturities	(28,968)	—	(6,222)	(35,715)	(70,905)
Long-term debt, less current maturities	195,532	185,116	77,000	169,642	627,290
Unamortized debt discount ⁽²⁾	—	(9,448)	—	—	(9,448)
Unamortized debt issuance costs ⁽³⁾	(1,623)	(853)	(5,123)	(2,741)	(10,340)
Long-term debt	\$193,909	\$174,815	\$71,877	\$166,901	\$607,502

(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.

(3) Debt issuance costs are amortized over the life of the applicable debt agreement.

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 a 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 (reduced to \$400 million by the February 2016 amendment to the Credit Agreement, as described below). Pursuant to our Credit Agreement, subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain 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 September 30, 2016, we had no borrowings under the Revolving Credit Facility and our available borrowing capacity under that facility, based on the leverage ratio covenant, totaled \$16.7 million, net of \$5.1 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.

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The Loans or portions thereof bearing interest at the base rate currently bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 3.00%. The Loans or portions thereof bearing interest at a LIBOR rate currently bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 4.00%. 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 vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We 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 4.00%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on a portion of our borrowings under the Term Loan (Note 14). The total notional amount of the swaps (initially \$148.1 million) decreases in proportion to the reduction in the principal amount outstanding under our Term Loan. The fixed LIBOR rates are approximately 75 basis points.

The Term Loan is repayable in scheduled principal installments (currently 10% or \$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. In September 2016, we elected to prepay \$8.0 million of the Term Loan. We may also 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.

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 and prepayment requirements, that 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 January 2016, we amended the Credit Agreement to permit the sale and lease back of certain office and warehouse property located in Aberdeen, Scotland. In February 2016, we amended the Credit Agreement to decrease the lenders’ commitment under the Revolving Credit Facility from \$600 million to \$400 million. As a result, we recorded a \$2.5 million interest charge to accelerate the amortization of debt issuance costs in proportion to the reduced commitment.

Also pursuant to the February 2016 amendment to the Credit Agreement:

(a) The minimum permitted Consolidated Interest Coverage Ratio was revised as follows:

	Minimum Consolidated Interest Coverage Ratio
Four Fiscal Quarters Ending	
March 31, 2016 through and including September 30, 2016	2.50 to 1.00
December 31, 2016 through and including March 31, 2017	2.75 to 1.00
June 30, 2017 and each fiscal quarter thereafter	3.00 to 1.00

(b) The maximum permitted Consolidated Leverage Ratio was revised as follows:

Four Fiscal Quarters Ending	Maximum Consolidated
-----------------------------	-------------------------

Leverage
Ratio

September 30, 2016 through and including December 31, 2016	5.00 to 1.00
March 31, 2017	4.75 to 1.00
June 30, 2017	4.25 to 1.00
September 30, 2017	3.75 to 1.00
December 31, 2017 and each fiscal quarter thereafter	3.50 to 1.00

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A new financial covenant was established requiring us to maintain a minimum cash balance if our Consolidated Leverage Ratio is 3.50x or greater, as described below. This minimum cash balance is not required to be maintained in any particular bank account or to be segregated from other cash balances in bank accounts that we use in our ordinary course of business. Because the use of this cash is not legally restricted notwithstanding this maintenance covenant, we present it as cash and cash equivalents on our balance sheet. As of September 30, 2016, we needed to maintain an aggregate cash balance of at least \$150 million in order to comply with this covenant.

Consolidated Leverage Ratio	Minimum Cash
Greater than or equal to 4.50x	\$150,000,000.00
Greater than or equal to 4.00x but less than 4.50x	\$100,000,000.00
Greater than or equal to 3.50x but less than 4.00x	\$50,000,000.00
Less than 3.50x	\$0.00

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 Credit Agreement's covenants (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, a wholly owned Scottish subsidiary. 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 Convertible Senior Notes in the aggregate principal amount of \$200 million 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 (either a Change of Control or a Termination of Trading, as those terms are defined in the Indenture governing the 2032 Notes).

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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. We recorded \$22.5 million related to the carrying amount of the equity component of the 2032 Notes. The remaining unamortized amount of the debt discount of the 2032 Notes was \$9.4 million at September 30, 2016 and \$15.0 million at December 31, 2015.

In June 2016, we repurchased \$7.3 million in aggregate principal amount of the 2032 Notes for \$6.5 million. In July 2016, we repurchased an additional \$7.6 million in aggregate principal amount of the 2032 Notes for \$7.0 million including \$0.1 million in accrued interest. The purchase price reflects the market price of the notes at the time of purchase. For the three- and nine-month periods ended September 30, 2016, we recognized gains of \$0.2 million and \$0.5 million, respectively, which are presented as “Gain on repurchase of long-term debt” in the accompanying consolidated statements of operations. Included in the gains were charges totaling \$0.5 million and \$1.0 million, respectively, for the acceleration of a pro rata portion of unamortized debt discount and debt issuance costs related to the 2032 Notes.

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 Q5000 Loan”) in an amount of up to \$250 million. The Nordea Q5000 Loan was funded in the amount of \$250 million in April 2015 at the time the Q5000 vessel was delivered to us. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., also a wholly owned Luxembourg subsidiary, guaranteed the Nordea Q5000 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 non-recourse to Helix.

The Nordea Q5000 Loan bears interest at a LIBOR rate plus a margin of 2.5%. The Nordea Q5000 Loan matures on April 30, 2020 and is repayable in scheduled quarterly principal installments of \$8.9 million with a balloon payment of \$80.4 million at maturity. Q5000 Holdings may elect to prepay amounts outstanding under the Nordea Q5000 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 June 2015, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on a portion of our borrowings under the Nordea Q5000 Loan (Note 14). The total notional amount of the swaps (initially \$187.5 million) decreases in proportion to the reduction in the principal amount outstanding under our Nordea Q5000 Loan. The fixed LIBOR rates are approximately 150 basis points.

The Nordea Credit Agreement and related loan documents include terms and conditions, including covenants and prepayment requirements, 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.

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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 a consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 30, 2016, we were in compliance with these covenants.

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

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
Interest expense	\$10,745	\$10,897	\$34,224	\$29,057
Interest income	(833)	(470)	(1,713)	(1,577)
Capitalized interest	(3,069)	(1,714)	(7,504)	(9,462)
Net interest expense	\$6,843	\$8,713	\$25,007	\$18,018
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 deferred tax 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.

The effective tax rates for the three- and nine-month periods ended September 30, 2016 were 24.1% and 26.7%, respectively. The effective tax rates for the three- and nine-month periods ended September 30, 2015 were 0.9% and 4.0%, respectively. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

Income taxes are provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items that are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the U.S. statutory rate and our effective rate are as follows:

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
U.S. statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(10.8)	(35.3)	(8.8)	(32.9)
Other	(0.1)	1.2	0.5	1.9
Effective rate	24.1 %	0.9 %	26.7 %	4.0 %

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Note 8 — Shareholders' Equity

On April 25, 2016, we launched an at-the-market ("ATM") equity offering program and executed an Equity Distribution Agreement with Wells Fargo Securities, LLC ("Wells Fargo") to sell up to \$50 million of our common stock through Wells Fargo. As of September 30, 2016, we had sold a total of 6,309,355 shares of our common stock under this ATM program for \$50 million, or an average of \$7.92 per share. The proceeds from the ATM program totaled \$47.7 million, net of transaction costs, including commissions of \$1.3 million to Wells Fargo.

On August 11, 2016, we executed another Equity Distribution Agreement with Wells Fargo to sell an additional \$50 million of our common stock under an ATM program. As of September 30, 2016, we had sold a total of 6,709,377 shares of our common stock under this ATM program for \$50 million, or an average of \$7.45 per share. The proceeds from this ATM program totaled \$48.8 million, net of transaction costs, including commissions of \$1.0 million to Wells Fargo.

The components of Accumulated Other Comprehensive Income (Loss) ("OCI") are as follows (in thousands):

	September 30, 2016	December 31, 2015
Cumulative foreign currency translation adjustment	\$ (67,548)	\$ (43,010)
Unrealized loss on hedges, net ⁽¹⁾	(18,026)	(27,891)
Accumulated other comprehensive loss	\$ (85,574)	\$ (70,901)

Amounts relate to foreign currency hedges for the Grand Canyon, Grand Canyon II and Grand Canyon III charters (1) as well as interest rate swap contracts for the Term Loan and the Nordea Q5000 Loan, and are net of deferred income taxes totaling \$9.8 million at September 30, 2016 and \$15.1 million at December 31, 2015 (Note 14).

Note 9 — Earnings Per Share

We have shares of restricted stock issued and outstanding that 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 of restricted stock 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. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not obligated to share in such losses.

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):

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	Three Months Ended September 30, 2016		Three Months Ended September 30, 2015	
	Income	Shares	Income	Shares
Basic:				
Net income	\$ 11,462		\$ 9,880	
Less: Undistributed earnings allocated to participating securities	(160)		(52)	
Undistributed earnings allocated to common shares	\$ 11,302	113,680	\$ 9,828	105,438
Diluted:				
Undistributed earnings allocated to common shares	\$ 11,302	113,680	\$ 9,828	105,438
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	—
Undistributed earnings reallocated to participating securities	—	—	—	—
Net income	\$ 11,302	113,680	\$ 9,828	105,438
	Nine Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	Income	Shares	Income	Shares
Basic:				
Net income (loss)	\$ (27,032)		\$ 26,887	
Less undistributed earnings allocated to participating securities	—		(149)	
Undistributed earnings (loss) allocated to common shares	\$ (27,032)	109,135	\$ 26,738	105,362
Diluted:				
Undistributed earnings (loss) allocated to common shares	\$ (27,032)	109,135	\$ 26,738	105,362
Effect of dilutive securities:				
Share-based awards other than participating securities	—	—	—	—
Undistributed earnings reallocated to participating securities	—	—	—	—
Net income (loss)	\$ (27,032)	109,135	\$ 26,738	105,362

We had a net loss for the nine-month period ended September 30, 2016. Accordingly, our diluted EPS calculation for the nine-month period ended September 30, 2016 was equivalent to our basic EPS calculation since diluted EPS excluded any assumed exercise or conversion of common stock equivalents. These common stock equivalents were excluded because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in the applicable period. Shares that otherwise would have been included in the diluted per share calculation assuming we had earnings are as follows (in thousands):

Nine
Months
Ended
September
30, 2016

Diluted shares (as reported)	109,135
Share-based awards	308
Total	109,443

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In addition, the following potentially dilutive shares related to the 2032 Notes were excluded from the diluted EPS calculation because we have the right and the intention to settle any such future conversions in cash (Note 6) (in thousands):

Three	Nine
Months	Months
Ended	Ended
September	September
30,	30,
2016	2015
2016	2015

2032 Notes 7,493 7,995 7,814 7,995

Note 10 — Employee Benefit Plans

Long-Term Incentive Stock-Based Plan

As of September 30, 2016, there were 3.9 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 (the “2005 Incentive Plan”). During the nine-month period ended September 30, 2016, 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 4, 2016 ⁽¹⁾	1,143,062	\$ 5.26	33% per year over three years
January 4, 2016 ⁽²⁾	1,143,062	\$ 7.13	100% on January 1, 2019
January 4, 2016 ⁽³⁾	11,763	\$ 5.26	100% on January 1, 2018
February 1, 2016 ⁽¹⁾	18,610	\$ 4.03	33% per year over three years
February 1, 2016 ⁽²⁾	18,610	\$ 7.13	100% on January 1, 2019
April 1, 2016 ⁽³⁾	13,727	\$ 5.60	100% on January 1, 2018
July 1, 2016 ⁽³⁾	8,476	\$ 6.76	100% on January 1, 2018

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

Reflects the grant of performance share units (“PSUs”) to our executive officers and select management employees.

The PSUs provide for an award based on the performance of our common stock over a three-year period with the (2) 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 (the “Board”).

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

Compensation cost for restricted stock is the product of grant date fair value of each share and the number of shares granted and is recognized over the applicable vesting period on a straight-line basis. For the three- and nine-month periods ended September 30, 2016, \$1.4 million and \$4.3 million, respectively, were recognized as share-based compensation related to restricted stock. For the three- and nine-month periods ended September 30, 2015, \$1.5 million and \$4.4 million, respectively, were recognized as share-based compensation related to restricted stock.

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The estimated fair value of the PSUs is determined using a Monte Carlo simulation model. Compensation cost for PSUs that are accounted for as equity awards is measured based on the estimated grant date fair value and recognized over the vesting period on a straight-line basis. PSUs that are accounted for as liability awards are measured based on the estimated fair value at the balance sheet date and changes in fair value of the awards are recognized in earnings. Cumulative compensation cost for vested liability PSU awards equals the actual cash payout amount upon vesting. In January 2015, in connection with the vesting of the 2012 PSU awards, a decision was made by the Compensation Committee of our Board to settle these PSUs in cash (rather than with an equivalent number of shares of our common stock, which was the default payment method for the 2012 PSU awards). Accordingly, PSUs, including those that were previously accounted for as equity awards, are treated as liability awards. To the extent the recognized fair value of the modified liability awards is less than the compensation cost associated with the grant date fair value of the original equity awards at the end of a reporting period, the higher amount is recorded as share-based compensation. The amount of cumulative compensation expense recognized in excess of the fair value of the modified liability awards is recorded in equity. For the three- and nine-month periods ended September 30, 2016, \$2.5 million and \$5.3 million, respectively, were recognized as share-based compensation related to PSUs. For the three-month period ended September 30, 2015, \$0.6 million was recognized as share-based compensation related to PSUs. For the nine-month period ended September 30, 2015, we recorded a net reduction of \$0.3 million of previously recognized compensation cost to reflect the estimated fair value of unvested PSUs as of September 30, 2015. The equity balance at September 30, 2016 and December 31, 2015 included \$3.0 million and \$2.9 million, respectively, reflecting the cumulative compensation expense recognized in excess of the estimated fair value of the modified liability PSU awards at the respective balance sheet dates. The liability balance for unvested PSUs was \$5.6 million at September 30, 2016 and \$0.7 million at December 31, 2015. We paid \$0.2 million in cash to settle the 2013 grant of PSUs when they vested in January 2016.

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 are indexed to our common stock with the payment amount at each vesting date, if any, determined by the performance of our common stock over the relevant performance period. Payout under these awards is 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 at the time of the award. Cash awards vest equally each year over a three-year period and payments under these awards are made on each anniversary date of the award. 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.

No long-term incentive cash awards were granted in 2015 or 2016. For the three- and nine-month periods ended September 30, 2015, we recorded reductions of \$1.2 million and \$3.7 million, respectively, of previously recognized compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans, reflecting the effect that decreases in our stock price had on the value of our liability plan. The liability balance for the cash awards issued under the LTI Cash Plans was less than \$0.1 million at December 31, 2015. We have reduced this liability balance down to zero at September 30, 2016 as we do not expect that these cash awards will meet the performance requirements for any payout.

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 0.7 million shares were available for issuance as of September 30, 2016. In February 2016, we suspended ESPP purchases for the January through April 2016 purchase period and indefinitely imposed a purchase limit of 130 shares per employee for subsequent purchase periods. Share-based compensation with respect to the ESPP was \$0.1 million for the three- and nine-month periods ended September 30, 2016 and \$0.3 million and \$0.9 million,

respectively, for the three- and nine-month periods ended September 30, 2015.

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 12 to our 2015 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 U.S., U.K. and Brazil well intervention operating segments are aggregated into the Well Intervention business segment for financial reporting purposes. Our Well Intervention segment includes our vessels and equipment used to perform well intervention services primarily in the U.S. 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 IRSs, some of which we rent out on a stand-alone basis, and SILs. Our Robotics segment includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services, and currently operates three chartered ROV support vessels. Our Production Facilities segment includes the HP I, the HFRS and our investment in Independence Hub that is accounted for under the equity method, and included our former ownership interest in Deepwater Gateway that we sold in February 2016 (Note 5). 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net revenues —				
Well Intervention	\$108,287	\$94,895	\$214,262	\$284,621
Robotics	48,897	83,310	119,805	238,582
Production Facilities	17,128	19,133	54,567	57,811
Intercompany elimination	(13,067)	(14,876)	(29,083)	(42,895)
Total	\$161,245	\$182,462	\$359,551	\$538,119
Income (loss) from operations —				
Well Intervention	\$24,413	\$6,233	\$7,187	\$25,162
Robotics	(94)	14,329	(21,667)	28,089
Production Facilities	8,312	6,938	25,225	19,960
Corporate and other	(10,288)	(8,965)	(28,784)	(24,581)
Intercompany elimination	(873)	(163)	(542)	(256)
Total	\$21,470	\$18,372	\$(18,581)	\$48,374

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Well Intervention	\$2,898	\$7,324	\$5,740	\$18,687
Robotics	10,169	7,552	23,343	24,208
Total	\$13,067	\$14,876	\$29,083	\$42,895

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

	September 30, 2016	December 31, 2015
Well Intervention	\$ 1,656,612	\$ 1,484,109
Robotics	242,252	274,926
Production Facilities	160,236	182,007
Corporate and other	372,446	458,917
Total	\$ 2,431,546	\$ 2,399,959

Note 12 — Commitments and Contingencies and Other Matters

Commitments

We have charter agreements for the Grand Canyon, Grand Canyon II and Grand Canyon III vessels for use in our robotics operations. Pursuant to the charter amendments in February 2016, in connection with charter rate reductions for the vessels, the term of the vessel charters was revised such that the Grand Canyon charter expires in October 2019, the Grand Canyon II charter expires in April 2021 and the Grand Canyon III charter expires in May 2023. We also have a charter agreement for the Deep Cygnus which expires in March 2018.

In September 2013, we executed a 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 being 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. Pursuant to a contract amendment we entered into in June 2015, 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 and to defer certain payment obligations. We paid \$7.3 million of these costs in July 2015 and the remaining costs were to be paid upon the delivery of the vessel. Pursuant to a second contract amendment we entered into in December 2015, the remaining 80% will be paid in three installments, with 20% in June 2016 (payment was made in October 2016 as agreed between the parties), 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. Also pursuant to this second amendment, we agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. Incremental costs are capitalized as they are incurred during the construction of the vessel. At September 30, 2016, our total investment in the Q7000 was \$190.1 million, including \$69.2 million paid to the shipyard upon signing the contract and the \$69.2 million shipyard invoice that was paid in October 2016.

In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil, and in connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS ("Siem") for two newbuild monohull vessels, the Siem Helix 1 and the Siem Helix 2. The initial term of the charter agreements with Siem is for seven years from the respective vessel delivery dates with options to extend. The initial term of the agreements with Petrobras is for four years with options to extend. As part of Petrobras's efforts to reduce its costs structure with many of its suppliers, we and Petrobras began discussions in mid-2015 with respect to potentially amending our contracts in a manner that addressed Petrobras's objectives and was acceptable to us as well. Those negotiations were finalized in early June 2016 such that the contracts for the Siem Helix 1, originally scheduled to begin no later than July 22, 2016, were amended to commence between July 22, 2016 and October 21, 2016, with the day rate reduced to a mutually acceptable level, and the contracts for the Siem Helix 2, originally scheduled to begin no later than January 21, 2017, were amended to commence between October 1, 2017 and December 31, 2017, with no change in the day rate.

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The Siem Helix 1 vessel was delivered to us and the charter term began on June 14, 2016. The vessel has transited to Brazil after integration and commissioning of our topside equipment onboard and is currently in the process of customer acceptance protocol and customer equipment integration. The Siem Helix 2 is under construction for the owner at the same shipyard that built the Siem Helix 1, and we anticipate that the vessel will be available for work in the second quarter of 2017 prior to commencing services for Petrobras in the fourth quarter of 2017. At September 30, 2016, our total investment in the topside equipment for the two vessels was \$179.5 million. In November 2014, we paid a charter fee deposit of \$12.5 million, which will be used to reduce our final charter payments for the Siem Helix 2.

Contingencies and Claims

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

Litigation

On July 31, 2015, a purported stockholder, Parviz Izadjoo, filed a class action lawsuit styled Parviz Izadjoo v. Owen Kratz and Helix Energy Solutions Group, Inc. against the Company and Mr. Kratz, our President and Chief Executive Officer, in the United States District Court for the Southern District of Texas on behalf of a putative class of all purchasers of shares of our common stock between October 21, 2014, and July 21, 2015, inclusive (the “Class Period”). The lawsuit asserts violations of Section 10(b) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and SEC Rule 10b-5 as to both us and Mr. Kratz, and Section 20(a) of the Exchange Act against Mr. Kratz, based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding projections for 2015 dry docks of two of our vessels working in the Gulf of Mexico that allegedly caused the price at which putative class members bought stock during the proposed class period to be artificially inflated. On January 28, 2016, the judge in the case approved a motion for the appointment of lead plaintiff and lead counsel. On March 14, 2016, the plaintiffs filed an amended class action complaint, adding Mr. Tripodo (our Executive Vice President and Chief Financial Officer) and Mr. Chamblee (our former Executive Vice President and Chief Operating Officer) as individual defendants, alleging the same types of claims made in the original complaint (alleged violations during the Class Period of Section 10(b) of the Exchange Act and SEC Rule 10b-5 with respect to all defendants, and Section 20(a) of the Exchange Act against the individual defendants), but asserting that the alleged misrepresentations and omissions in SEC filings and other public disclosures are related to the condition of and repairs to certain equipment aboard the Q4000 vessel. The defendants filed a motion to dismiss on April 28, 2016 and the parties have completed briefing on that motion. We believe this lawsuit to be without merit and intend to vigorously defend against it.

We are involved in various other 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).

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(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, receivables, accounts payable, long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, trade and other current receivables as well as accounts payable approximates fair value due to the short-term nature of these instruments. The net carrying amount of our long-term note receivable also approximates its fair value. The following tables provide additional information relating to other financial instruments measured at fair value on a recurring basis (in thousands):

	Fair Value Measurements at September 30, 2016 Using			
	Level 1 Value (1)	Level 2 Value	Level 3 Value	Total Valuation Technique
Liabilities:				
Foreign exchange contracts	\$—	\$35,614	\$—	\$35,614 (c)
Interest rate swaps	—	2,490	—	2,490 (c)
Total liability	\$—	\$38,104	\$—	\$38,104

	Fair Value Measurements at December 31, 2015 Using			
	Level 1 Value (1)	Level 2 Value	Level 3 Value	Total Valuation Technique
Assets:				
Interest rate swaps	\$—	\$413	\$—	\$413 (c)

Liabilities:				
Foreign exchange contracts	—	61,427	—	61,427 (c)
Interest rate swaps	—	1,473	—	1,473 (c)
Total net liability	\$—	\$62,487	\$—	\$62,487

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.

(1) 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 discussions on the fair value of our derivative instruments.

The carrying values and estimated fair values of our long-term debt are as follows (in thousands):

	September 30, 2016		December 31, 2015	
	Carrying Value (1)	Fair Value (2)	Carrying Value (1)	Fair Value (2)
Term Loan (matures June 2018)	\$224,500	\$223,658	\$255,000	\$248,467
Nordea Q5000 Loan (matures April 2020)	205,357	201,123	232,143	221,553
MARAD Debt (matures February 2027)	83,222	95,015	89,148	104,897
2032 Notes (mature March 2032)	185,116	177,711	200,000	150,250

Total debt	\$698,195	\$697,507	\$776,291	\$725,167
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(1) Carrying value includes current maturities and excludes the related unamortized debt discount and debt issuance costs. See Note 6 for additional disclosures on our long-term debt.

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The estimated fair value of the 2032 Notes was determined using Level 1 inputs under the market approach. The fair value of the Term Loan, the Nordea Q5000 Loan and the MARAD Debt was estimated using Level 2 fair value (2) inputs under the market approach. The fair value of the Term Loan, the Nordea Q5000 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.

Note 14 — Derivative Instruments and Hedging Activities

Our business is exposed to market risks 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. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we enter into certain derivative contracts, including interest rate swaps and foreign currency exchange contracts. 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 18 to our 2015 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 Q5000 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 cash flow 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 around 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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During discussions with the owner of the Grand Canyon, Grand Canyon II and Grand Canyon III vessels with respect to amending the charter agreements, it became apparent in December 2015 that a portion of previously forecasted charter payments in NOK would no longer be made. We concluded that the foreign currency exchange contracts associated with the charter payments for the Grand Canyon still qualified for cash flow hedge accounting treatment. However, the foreign currency exchange contracts associated with the charter payments for the Grand Canyon II and the Grand Canyon III vessels no longer qualified as cash flow hedges. As a result, we de-designated these hedges and re-designated the hedging relationship between a portion of our foreign currency exchange contracts and our forecasted Grand Canyon II and Grand Canyon III charter payments of NOK434.1 million and NOK185.2 million, respectively, that were expected to remain highly probable of occurring. Unrealized losses associated with the effective portion of the re-designated foreign currency exchange contracts that qualify for hedge accounting treatment are included in our Accumulated OCI (net of tax). Changes in unrealized losses associated with the ineffective portion of the re-designated foreign currency exchange contracts are reflected in "Other income (expense), net" in the accompanying condensed consolidated statement of operations. "Other income (expense), net" also includes changes in unrealized losses associated with the foreign currency exchange contracts that are no longer designated as cash flow hedges.

Quantitative Disclosures Relating to Derivative Instruments

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

	September 30, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	\$—	Other assets, net	\$413
		\$—		\$413
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	\$12,897	Accrued liabilities	\$14,955
Interest rate swaps	Accrued liabilities	1,212	Accrued liabilities	1,473
Foreign exchange contracts	Other non-current liabilities	12,776	Other non-current liabilities	28,458
Interest rate swaps	Other non-current liabilities	1,278	Other non-current liabilities	—
		\$28,163		\$44,886

The following table presents the fair value and balance sheet classification of our derivative instruments that were not designated as hedging instruments (in thousands):

	September 30, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	\$3,612	Accrued liabilities	\$6,763
Foreign exchange contracts	Other non-current liabilities	6,329	Other non-current liabilities	11,251
		\$9,941		\$18,014

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For the nine-month period ended September 30, 2016, we recorded unrealized gains \$0.1 million related to our hedge ineffectiveness. Realized gains for the nine-month period ended September 30, 2016 as well as realized and unrealized gains for the three-month period ended September 30, 2016 related to the hedge ineffectiveness were immaterial. For the three- and nine-month periods ended September 30, 2015, we recorded unrealized losses of \$0.4 million and \$3.6 million, respectively, and realized losses of \$0.3 million and \$0.4 million, respectively, related to our hedge ineffectiveness. The following tables present the impact that derivative instruments designated as hedging instruments had on our Accumulated OCI (net of tax) and our condensed consolidated statements of operations (in thousands). We estimate that as of September 30, 2016, \$8.9 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 (Effective Portion)

Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
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Foreign exchange contracts	\$4,249	\$(5,777)	\$10,745	\$(7,136)
Interest rate swaps	643	(975)	(880)	(1,848)
	\$4,892	\$(6,752)	\$9,865	\$(8,984)

Location of Loss Reclassified from Accumulated OCI into Earnings	Loss Reclassified from Accumulated OCI into Earnings (Effective Portion)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
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Foreign exchange contracts	Cost of sales	\$(2,663)	\$(3,433)	\$(8,033)	\$(7,828)
Interest rate swaps	Net interest expense	(494)	(822)	(1,618)	(1,358)
		\$(3,157)	\$(4,255)	\$(9,651)	\$(9,186)

The following table presents the impact that derivative instruments not designated as hedging instruments had on our condensed consolidated statement of operations (in thousands):

Location of Gain Recognized in Earnings on Derivatives	Gain Recognized in Earnings on Derivatives	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
--	---	--	--	--	--

Foreign exchange contracts	Other income (expense), net	\$1,309	\$	—\$3,375	\$	—
		\$1,309	\$	—\$3,375	\$	—

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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 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," "plan," "project," "propose," "strategy," "predict," "intend," "will," "continue," "may," "potential," "should," "could" and similar 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 the Siem Helix 2 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, debt and liquidity, 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 our trade receivables and their collectability;
- 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 our 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:

- the 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;
- the impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the impact of any potential cancellation, deferral or modification of our work or contracts by our customers;
- unexpected delays in the delivery or chartering or customer acceptance of new vessels for our well intervention and robotics fleet, including the Q7000, the Grand Canyon III, and the Siem Helix 1 and the Siem Helix 2 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 effects of our indebtedness and our ability to reduce capital commitments;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;

the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations;
the impact of current and future laws and governmental regulations, including tax and accounting developments;
the impact of the vote in the U.K. to exit the European Union (“Brexit”) on our business, operations and financial condition, which is unknown at this time;

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- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- 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 2015 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. From time to time, we make strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention fleet has expanded following the delivery of the Siem Helix 1 chartered vessel in June 2016 and is expected to further expand following the completion and delivery of the Q7000, a newbuild semi-submersible vessel, in late 2017 or in 2018, and the delivery of the Siem Helix 2 chartered vessel in early 2017. With respect to our robotics business, the Grand Canyon III chartered vessel was delivered by the shipyard to the vessel owner in May 2016. The vessel is currently stacked by the owner and is expected to be in service for us in May 2017. The Rem Installer charter expired in July 2016. Our new fixed fee agreement with the same operator for the HP I to service the Phoenix field until at least June 1, 2023 enhances the long-term prospects for our production facilities assets.

In January 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 customers, combining marine support with well access and control technologies. In April 2015, we and OneSubsea jointly ordered a 15,000 working p.s.i. IRS, which is expected to be completed by July 2017 for a total cost of approximately \$27.5 million (approximately \$13.8 million for our 50% interest). At September 30, 2016, our total investment in the IRS was \$4.4 million. In October 2016, we and OneSubsea announced the launch of the development of the first Riserless Open-water Abandonment Module (“ROAM”) for an estimated cost of approximately \$12 million (approximately \$6 million for our 50% interest). The ROAM is expected to be available to customers in the third quarter of 2017.

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:

- 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 level of excess production capacity;
the ability of oil and gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;

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the sale and expiration dates of offshore leases in the United States and overseas;
 technological advances affecting energy exploration, production, transportation and consumption;
 potential acceleration of the development of alternative fuels;
 shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
 weather conditions and natural disasters;
 environmental and other governmental regulations; and
 domestic and international tax laws, regulations and policies.

The significant decline in oil prices since mid-year 2014 as a result of continued global supply of oil in excess of demand has had a significant adverse impact on investments in oil and gas exploration and production. Many oil and gas companies have terminated or not renewed contracts for more than half of their contracted rigs and have drastically cut investments in exploration and production as well as other operational activities. We expect these challenging industry conditions to continue through 2016 and beyond if oil and gas prices fail to increase to a level conducive to increased activity levels. Increased competition for limited offshore oil and gas projects has driven down rates that drilling rig contractors are charging for their services, which affects all offshore oil and gas services contractors, including us. Increased competition is also expected to affect utilization of our assets. In addition, the current volatile and uncertain macroeconomic conditions in some countries around the world, such as Brazil and more recently the U.K. following Brexit, may have a direct and/or indirect impact on our existing contracts and contracting opportunities and may introduce further currency volatility into our operations and/or financial results. We are continuing to monitor the impact of Brexit and any exit agreements as they are negotiated, but the impact from Brexit on our business and operations will depend on the outcome of tariff, tax treaties, trade, regulatory and other negotiations, as well as the impact of Brexit on macroeconomic growth and currency volatility, which are uncertain at this time.

Many oil and gas companies are increasingly focusing on optimizing production of their existing subsea wells. We believe that we have a competitive advantage in terms of performing well intervention services efficiently. Furthermore, we believe that when oil and gas companies begin to increase overall spending levels, it will likely be for production activities rather than for exploration projects. 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 prolongation of well life in oil and gas production is the primary driver of demand for our services.

Our current strategy is to be positioned for future recovery while coping with a sustained period of weak activity. This strategy is based on the following factors: (1) the need to extend the life of subsea wells is significant to the commercial viability of the wells as plug and abandonment costs are considered; (2) our services offer commercially viable alternatives for reducing the finding and development costs of reserves as compared to new drilling; and (3) in past cycles, well intervention and workover have been one of the first activities to recover, and in a prolonged market downturn are important to the commercial viability of deepwater wells.

Helix Fast Response System

We developed the HFRS as a culmination of our experience as a responder in the 2010 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 an option to extend the agreement with us through March 31, 2018.

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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 U.S. Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, and are expanding our operations offshore Brazil. In addition to servicing the oil and gas market, our Robotics operations are contracted for the development of renewable energy projects (wind farms). As of September 30, 2016, our consolidated backlog that is supported by written agreements or contracts totaled \$1.9 billion, of which \$120.6 million is expected to be performed in 2016. The substantial majority of our backlog is associated with our Well Intervention business segment. As of September 30, 2016, our well intervention backlog was \$1.5 billion, including \$84.1 million expected to be performed in the fourth quarter of 2016. Our five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel, our four-year agreements with Petrobras to provide well intervention services offshore Brazil with the Siem Helix 1 and Siem Helix 2 chartered vessels, and our new seven-year fixed fee agreement for the HP I represent approximately 92% 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.

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. Non-GAAP financial measures should be viewed in addition to, and not as an alternative to, our reported results prepared in accordance with U.S. GAAP. Users of this financial information should consider the types of events and transactions that are excluded from these non-GAAP measures.

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 U.S. 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 that 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 earnings before income taxes, net interest expense, gain on repurchase on long-term debt, net other income or expense, and depreciation and amortization expense. To arrive at our measure of Adjusted EBITDA, when applicable, we include realized losses from the cash settlements of our ineffective foreign currency exchange contracts, which are excluded from EBITDA as a component of net other income or expense. In the following reconciliation, we provide amounts as reflected in our accompanying condensed consolidated financial statements unless otherwise footnoted.

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Other companies may calculate their measures of EBITDA and Adjusted EBITDA differently from the way we do, which may limit their usefulness as comparative measures. Because EBITDA and Adjusted EBITDA are not financial measures calculated in accordance with U.S. GAAP, they should not be considered in isolation or as a substitute for, but instead are supplemental to, income from operations, net income or other income data prepared in accordance with U.S. GAAP. The reconciliation of our net income (loss) to EBITDA and Adjusted EBITDA is as follows

(in thousands):

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2016	
	2015		2015	
Net income (loss)	\$11,462	\$9,880	\$(27,032)	\$26,887
Adjustments:				
Income tax provision (benefit)	3,649	94	(9,858)) 1,115
Net interest expense	6,843	8,713	25,007	18,018
Gain on repurchase of long-term debt	(244)) —	(546)) —
Other (income) expense, net	(830)) 5	(4,018)) 6,197
Depreciation and amortization	27,607	32,805	84,846	86,333
EBITDA	48,487	51,497	68,399	138,550
Adjustments:				
Realized losses from cash settlements of ineffective foreign currency exchange contracts	(1,786)) —	(5,744)) —
Adjusted EBITDA	\$46,701	\$51,497	\$62,655	\$138,550

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Comparison of Three Months Ended September 30, 2016 and 2015

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

	Three Months Ended September 30,		Increase/ (Decrease)
	2016	2015	
Net revenues —			
Well Intervention	\$108,287	\$94,895	\$ 13,392
Robotics	48,897	83,310	(34,413)
Production Facilities	17,128	19,133	(2,005)
Intercompany elimination	(13,067)	(14,876)	1,809
	\$161,245	\$182,462	\$ (21,217)
Gross profit (loss) —			
Well Intervention	\$28,174	\$8,967	\$ 19,207
Robotics	4,953	17,071	(12,118)
Production Facilities	8,413	7,125	1,288
Corporate and other	(483)	(1,031)	548
Intercompany elimination	(873)	(163)	(710)
	\$40,184	\$31,969	\$ 8,215
Gross margin —			
Well Intervention	26%	9%	
Robotics	10%	20%	
Production Facilities	49%	37%	
Total company	25%	18%	
Number of vessels or robotics assets ⁽¹⁾ / Utilization ⁽²⁾			
Well Intervention vessels	5/76%	5/60%	
Robotics assets	60/57%	60/59%	
Chartered robotics vessels	3/81%	5/87%	

Represents number of vessels or robotics 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.

(1) The Helix 534 was excluded from the numbers for the third quarter of 2016 as it was stacked and out of service.

The Seawell was excluded from the numbers for the first two months of the third quarter of 2015 as it was out of service undergoing major capital upgrades.

(2) Represents average utilization rate, which is calculated by dividing the total number of days the vessels or robotics 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 September 30, 2016 2015		Increase/ (Decrease)
Well Intervention	\$2,898	\$7,324	\$ (4,426)
Robotics	10,169	7,552	2,617
	\$13,067	\$14,876	\$ (1,809)

Net Revenues. Our total net revenues decreased by 12% for the three-month period ended September 30, 2016 as compared to the same period in 2015. The revenue decrease for the three-month period in 2016 was primarily attributable to our Robotics and Production Facilities business segments, offset in part by a revenue increase in our Well Intervention business segment.

Our Well Intervention revenues increased by 14% for the three-month period ended September 30, 2016 as compared to the same period in 2015 reflecting higher revenues in our U.S. Gulf of Mexico region, offset in part by lower revenues in our North Sea region primarily due to our acceptance of work at reduced rates. In the Gulf of Mexico, the Q4000 was 93% utilized during the third quarter of 2016 as compared to 67% utilized during the same period in 2015. In addition, we recognized \$15.6 million associated with a work scope cancellation under a contract containing “take or pay” provisions for 42 days of work originally scheduled to be performed by the Q4000 in the fourth quarter of 2016. The Q5000, which went on contracted rates under our five-year contract with BP in May 2016, was 84% utilized during the third quarter of 2016. The Helix 534 had no utilization in the comparable quarter-over-quarter periods. In the North Sea, the Well Enhancer was 91% utilized during the comparable periods in 2015 and 2016. The Seawell was 98% utilized during the third quarter of 2016 as compared to being warm stacked following the completion of its life extension capital upgrades in September 2015. The Skandi Constructor was 15% utilized during the third quarter of 2016 as compared to being fully utilized during the same period in 2015.

Robotics revenues decreased by 41% for the three-month period ended September 30, 2016 as compared to the same period in 2015. The decrease primarily reflects the reduction and lower utilization of our available Robotics assets, including our chartered vessels, and accepting work at reduced rates. Some of our ROV units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas industry downturn. Utilization of our chartered ROV support vessels decreased primarily reflecting reduction in work opportunities as a result of further market deterioration in the offshore energy industry.

Our Production Facilities revenues decreased by 10% for the three-month period ended September 30, 2016 as compared to the same period in 2015, which primarily reflects lower revenues from the new fixed fee agreement for production from the Phoenix field (Note 2) as compared to the variable throughput fee arrangement that was previously in place.

Gross Profit (Loss). Our total gross profit increased by 26% for the three-month period ended September 30, 2016 as compared to the same period in 2015. The gross profit related to our Well Intervention segment increased by 214% for the three-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting higher gross profit achieved in our Gulf of Mexico region as a result of the Q5000 being on hire under the BP contract for the entire quarter as well as the \$15.6 million in revenues associated with the take-or-pay contract as previously discussed. The increase in our Well Intervention gross profit was partially offset by a reduction in gross profit in our North Sea region as a result of the decrease in revenues.

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The gross profit associated with our Robotics segment decreased by 71% for the three-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting decreased utilization for our Robotics assets, including our chartered vessels, and accepting work with lower profit margins.

The gross profit related to our Production Facilities segment increased by 18% for the three-month period ended September 30, 2016 as compared to the same period in 2015. The increase primarily reflects operating cost reductions as the the HP I went into its scheduled regulatory dry dock in September 2016, lower repair and maintenance costs, and a decrease in depreciation expense related to the HP I as a result of the vessel's impairment in December 2015.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by \$5.1 million for the three-month period ended September 30, 2016 as compared to the same period in 2015. The increase was primarily attributable to an increase in payroll related costs associated with our variable performance-based incentive compensation programs (Note 10) as well as increased overhead costs associated with the Petrobras contract, and was partially offset by overhead cost saving measures including headcount reductions. In addition, selling, general and administrative expenses for the three-month period ended September 30, 2016 included a \$2.7 million charge associated with the provision for uncertain collection of a portion of our long-term note receivable.

Net Interest Expense. Our net interest expense decreased by \$1.9 million for the three-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting increases in interest income and capitalized interest. Interest income totaled \$0.8 million for the three-month period ended September 30, 2016 as compared to \$0.5 million for the same period in 2015. Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled \$3.1 million for the three-month period ended September 30, 2016 as compared to \$1.7 million for the same period in 2015.

Gain on Repurchase of Long-Term Debt. The \$0.2 million gain for the three-month period ended September 30, 2016 was associated with the repurchase in July 2016 of \$7.6 million in aggregate principal amount of our 2032 Notes (Note 6).

Other Income (Expense), Net. We reported other income, net, of \$0.8 million for the three-month period ended September 30, 2016 as compared to a minimal amount in other expense, net, for the same period in 2015. Net other income for the three-month period ended September 30, 2016 primarily reflects net gains totaling \$1.3 million associated with our foreign currency exchange contracts which primarily related to the contracts that were not designated as cash flow hedges (Note 14). Net other expense for the three-month period ended September 30, 2015 primarily reflects losses totaling \$0.7 million related to our hedge ineffectiveness (Note 14). Also included in other income (expense), net, were foreign currency transaction gains (losses) of \$(0.5) million and \$0.7 million, respectively, in the comparable quarter-over-quarter periods.

Other Income (Expense) – Oil and Gas. We reported other oil and gas expense of \$0.5 million for the three-month period ended September 30, 2016 as compared to other oil and gas income of \$0.6 million for the same period in 2015. The variance was attributable to the regulatory compliance costs associated with the reclamation of a non-producing offshore U.K. oil and gas property and the reduction in income from a well in the Phoenix field in which we have an overriding royalty interest. The decrease in the overriding royalty income was significantly affected by lower volumes which were partially attributable to the HP I going into its scheduled regulatory dry dock in September 2016.

Income Tax Provision. Income taxes reflect expenses of \$3.6 million for the three-month period ended September 30, 2016 as compared to \$0.1 million for the same period in 2015. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 24.1% for the three-month period ended September 30, 2016 was higher than the 0.9% effective tax rate for the same period in 2015. The variance was primarily attributable to the

earnings mix between our higher and lower tax rate jurisdictions.

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Comparison of Nine Months Ended September 30, 2016 and 2015

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

	Nine Months Ended September 30,		Increase/ (Decrease)
	2016	2015	
Net revenues —			
Well Intervention	\$214,262	\$284,621	\$(70,359)
Robotics	119,805	238,582	(118,777)
Production Facilities	54,567	57,811	(3,244)
Intercompany elimination	(29,083)	(42,895)	13,812
	\$359,551	\$538,119	\$(178,568)
Gross profit (loss) —			
Well Intervention	\$17,195	\$34,769	\$(17,574)
Robotics	(12,008)	39,181	(51,189)
Production Facilities	25,634	20,472	5,162
Corporate and other	(1,367)	(3,042)	1,675
Intercompany elimination	(542)	(256)	(286)
	\$28,912	\$91,124	\$(62,212)
Gross margin —			
Well Intervention	8%	12%	
Robotics	(10)%	16%	
Production Facilities	47%	35%	
Total company	8%	17%	
Number of vessels or robotics assets ⁽¹⁾ / Utilization ⁽²⁾			
Well Intervention vessels	5/52%	5/63%	
Robotics assets	60/48%	60/60%	
Chartered robotics vessels	3/63%	5/85%	

Represents number of vessels or robotics 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.

(1) The Helix 534 was excluded from the numbers for the first nine months of 2016 as it was stacked and out of service. The Seawell was excluded from the numbers for the first eight months of 2015 as it was out of service undergoing major capital upgrades.

(2) Represents average utilization rate, which is calculated by dividing the total number of days the vessels or robotics 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):

	Nine Months Ended September 30, 2016 2015		Increase/ (Decrease)
Well Intervention	\$5,740	\$18,687	\$(12,947)
Robotics	23,343	24,208	(865)
	\$29,083	\$42,895	\$(13,812)

Net Revenues. Our total net revenues decreased by 33% for the nine-month period ended September 30, 2016 as compared to the same period in 2015. In general, decreased revenues for the nine-month period in 2016 reflect both reduced opportunities for work and the acceptance of work at reduced rates for some of our assets in light of the continuation of industry-wide downturn as a result of the substantial decline in oil prices since late 2014.

Our Well Intervention revenues decreased by 25% for the nine-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting significantly lower revenues in our North Sea region due to lack of work and our acceptance of work at reduced rates, offset in part by revenue increases in our U.S. Gulf of Mexico region. In the North Sea, the Well Enhancer was 60% utilized during the first nine months of 2016 while the vessel was 96% utilized during the same period in 2015. The Skandi Constructor was 5% utilized during the first nine months of 2016 as compared to being 60% utilized during the same period in 2015. The Seawell was re-activated in June 2016 and was 41% utilized during the first nine months of 2016 as compared to being out of service undergoing its life extension capital upgrades during the first eight months of 2015 and being warm stacked in September 2015. In the Gulf of Mexico, the Q4000 was 97% utilized during the first nine months of 2016 as compared to 62% utilized during the same period in 2015. Idle time for the Q4000 included 64 days in the second quarter of 2015 for its scheduled regulatory dry dock, and some downtime attributable to IRS mechanical issues in January 2015. In addition, we recognized \$15.6 million associated with a work scope cancellation under a contract containing “take or pay” provisions for 42 days of work originally scheduled to be performed by the Q4000 in the fourth quarter of 2016. The Q5000, which was delivered to us in April 2015 and went on contracted rates under our five-year contract with BP in May 2016, was 56% utilized in 2016. The Helix 534 was stacked and out of service during the first nine months of 2016 while the vessel was 42% utilized during the same period in 2015.

Robotics revenues decreased by 50% for the nine-month period ended September 30, 2016 as compared to the same period in 2015. The decrease primarily reflects the reduction and lower utilization of our available Robotics assets, including our chartered vessels, and accepting work at reduced rates. Some of our ROV units have been affected by other industry participants laying up vessels or canceling work as a result of the oil and gas industry downturn. Utilization of our chartered ROV support vessels decreased primarily reflecting reduction in work opportunities as a result of further market deterioration in the offshore energy industry.

Our Production Facilities revenues decreased by 6% for the nine-month period ended September 30, 2016 as compared to the same period in 2015, which reflects lower revenues from the new fixed fee agreement for production from the Phoenix field starting June 1, 2016 (Note 2) as well as the slight decrease in our variable throughput fee for the first five months of 2016 as compared to the same period in 2015.

Gross Profit (Loss). Our total gross profit decreased by 68% for the nine-month period ended September 30, 2016 as compared to the same period in 2015. The gross profit related to our Well Intervention segment decreased by 51% for the nine-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting

significantly lower revenues from most of our well intervention vessels in our North Sea region during the first nine months of 2016 due to lack of available projects and acceptance of work at reduced rates as a result of the ongoing industry downturn. The decrease in our Well Intervention gross profit was partially offset by higher gross profit achieved in our Gulf of Mexico region as a result of the Q5000 being on hire under the BP contract since May 2016 as well as the \$15.6 million in revenues associated with the take-or-pay contract as previously discussed.

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The gross profit associated with our Robotics segment decreased from \$39.2 million for the nine-month period ended September 30, 2015 to a \$12.0 million loss for the nine-month period ended September 30, 2016 primarily reflecting decreased utilization for our Robotics assets, including our chartered vessels, and accepting work with lower profit margins.

The gross profit related to our Production Facilities segment increased by 25% for the nine-month period ended September 30, 2016 as compared to the same period in 2015. The increase primarily reflects lower repair and maintenance costs and a decrease in depreciation expense related to the HP I as a result of the vessel's impairment in December 2015.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by \$4.7 million for the nine-month period ended September 30, 2016 as compared to the same period in 2015. The increase was primarily attributable to payroll related costs associated with our variable performance-based incentive compensation programs (Note 10) as well as increased overhead costs associated with the Petrobras contract, and was partially offset by overhead cost saving measures including headcount reductions.

Net Interest Expense. Our net interest expense increased by \$7.0 million for the nine-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting an increase in interest expense and a decrease in capitalized interest. The increase in interest expense was primarily attributable to nearly four months of additional interest on the Nordea Q5000 Loan, which was funded in April 2015, as well as increases in interest rates on the Term Loan and the Nordea Q5000 Loan. Interest expense for the nine-month period ended September 30, 2016 also included a \$2.5 million charge to accelerate the amortization of debt issuance costs in proportion to the reduced commitment under our Revolving Credit Facility in February 2016 (Note 6). Interest on debt used to finance capital projects is capitalized and thus reduces overall interest expense. Capitalized interest totaled \$7.5 million for the nine-month period ended September 30, 2016 as compared to \$9.5 million for the same period in 2015.

Gain on Repurchase of Long-Term Debt. The \$0.5 million gain for the nine-month period ended September 30, 2016 was associated with the repurchases totaling \$14.9 million in aggregate principal amount of our 2032 Notes in June and July of 2016 (Note 6).

Other Income (Expense), Net. We reported other income, net, of \$4.0 million for the nine-month period ended September 30, 2016 as compared to other expense, net, of \$6.2 million for the same period in 2015. Net other income for the nine-month period ended September 30, 2016 primarily reflects net gains totaling \$3.5 million associated with our foreign currency exchange contracts which primarily related to the contracts that were not designated as cash flow hedges (Note 14). Net other expense for the nine-month period ended September 30, 2015 primarily reflects losses totaling \$4.0 million related to our hedge ineffectiveness (Note 14). Also included in other income (expense), net, were foreign currency transaction gains (losses) of \$0.5 million and \$(2.2) million, respectively, in the comparable year-over-year periods.

Other Income – Oil and Gas. Our other income – oil and gas decreased by \$1.9 million for the nine-month period ended September 30, 2016 as compared to the same period in 2015. The decrease was primarily attributable to the reduction in our overriding royalty income which was significantly affected by the decline in oil prices and lower volumes.

Income Tax Provision (Benefit). Income taxes reflect a benefit of \$9.9 million for the nine-month period ended September 30, 2016 as compared to a provision of \$1.1 million for the same period in 2015. The variance primarily reflects decreased profitability in the current year period. The effective tax rate was a 26.7% benefit for the nine-month period ended September 30, 2016 as compared to a 4.0% expense for the same period in 2015. The variance was primarily attributable to the earnings mix between our higher and lower tax rate jurisdictions.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2016	December 31, 2015
Net working capital	\$ 410,468	\$ 473,123
Long-term debt ⁽¹⁾	\$ 607,502	\$ 677,695
Liquidity ⁽²⁾	\$ 498,854	\$ 743,577

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

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 (2) September 30, 2016 included cash and cash equivalents of \$482.1 million (including \$150 million of minimum cash balance) and \$16.7 million of available borrowing capacity under our Revolving Credit Facility (Note 6). Our liquidity at December 31, 2015 included cash and cash equivalents of \$494.2 million and \$249.4 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our long-term debt, including current maturities, net of unamortized debt discount and debt issuance costs, is as follows (in thousands):

	September 30, 2016	December 31, 2015
Term Loan (matures June 2018)	\$ 222,877	\$ 253,181
Nordea Q5000 Loan (matures April 2020)	202,616	228,840
MARAD Debt (matures February 2027)	78,099	83,659
2032 Notes (mature March 2032) ⁽¹⁾	174,815	183,655
Total debt	\$ 678,407	\$ 749,335

(1) The 2032 Notes will increase to their 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.

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

	Nine Months Ended September 30,	
	2016	2015
Cash provided by (used in):		
Operating activities	\$15,444	\$39,429
Investing activities	\$(42,266)	\$(267,170)
Financing activities	\$17,217	\$221,244

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Our current requirements for cash primarily reflect the need to fund capital spending 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 project financing, along with other debt and equity alternatives.

As a further response to the industry-wide spending reductions, 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 our cash on hand, internally generated cash flows and 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 a consolidated leverage ratio, as well as the maintenance of minimum cash balance, 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 Q5000 Loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Our 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 defined in our Credit Agreement). As of September 30, 2016 and December 31, 2015, we were in compliance with all of the covenants of our long-term debt.

A prolonged period of weak industry 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 under our Revolving Credit Facility may be impacted. At September 30, 2016, our available borrowing capacity under our Revolving Credit Facility, based on the leverage ratio covenant, was restricted to \$16.7 million, net of \$5.1 million of letters of credit issued. We anticipate that our borrowing capacity under the Revolving Credit Facility will slightly increase over the remainder of 2016. We currently 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, that 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.

Subject to the terms and restrictions of the Credit Agreement, as amended, we may borrow and/or obtain letters of credit up to \$400 million under our Revolving Credit Facility. Pursuant to our Credit Agreement, subject to existing lender participation and/or the participation of new lenders, and subject to standard conditions precedent, we may obtain an increase of up to \$200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. 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 nine-month periods ended September 30, 2016 and 2015.

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Operating Cash Flows

Total cash flows from operating activities decreased by \$24.0 million for the nine-month period ended September 30, 2016 as compared to the same period in 2015. This decrease primarily reflects decreases in income from operations and changes in our working capital. Our operating cash flows for the nine-month period ended September 30, 2016 included the receipt of \$28.4 million in U.S. and foreign income tax refunds.

Investing Activities

Capital expenditures consist principally of the construction of dynamically positioned vessels as well as improvements and modifications to existing assets. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Nine Months Ended September 30,	
	2016	2015
Capital expenditures:		
Well Intervention	\$(79,147)	\$(269,246)
Robotics	(504)	(10,582)
Production Facilities	(74)	(863)
Other	372	168
Distributions from equity investments, net ⁽¹⁾	1,200	5,853
Proceeds from sale of equity investment ⁽²⁾	25,000	—
Proceeds from sale of assets ⁽³⁾	10,887	7,500
Net cash used in investing activities	\$(42,266)	\$(267,170)

Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross (1) distributions from our equity investments for the nine-month periods ended September 30, 2016 and 2015 were \$1.2 million and \$5.3 million, respectively (Note 5).

(2) Amount in 2016 reflects cash received from the sale of our former ownership interest in Deepwater Gateway (Notes 2 and 5).

(3) Amount in 2015 reflects cash received from the sale of our former Ingleside spoolbase.

Capital expenditures associated with our business primarily have included payments associated with the construction of our Q5000 and Q7000 vessels (see below), payments in connection with the Seawell life extension activities in 2015, the investment in the topside well intervention equipment for the Siem Helix 1 and Siem Helix 2 vessels chartered to perform under our agreements with Petrobras (see below), and the acquisition of additional ROVs for our robotics business.

In March 2012, we entered into a contract with a shipyard in Singapore for 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 Q5000 was delivered to us in the second quarter of 2015. The vessel commenced operations in the Gulf of Mexico under our five-year contract with BP and went on contracted rates on May 19, 2016.

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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 being 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. In June 2015, we entered into a contract amendment with the shipyard to extend the scheduled delivery of the Q7000 from mid-2016 to July 30, 2017 and to defer certain payment obligations, and in connection with this extension, we agreed to pay the shipyard incremental costs of up to \$14.5 million. In December 2015, we entered into a second contract amendment with the shipyard. Pursuant to this amendment, the remaining 80% will be paid in three installments, with 20% in June 2016, 20% upon issuance of the Completion Certificate, which is to be issued on or before December 31, 2017, and 40% upon the delivery of the vessel, which at our option can be deferred until December 30, 2018. Also pursuant to this second amendment, we agreed to reimburse the shipyard for incremental costs in connection with the further deferment of the Q7000's delivery. At September 30, 2016, our total investment in the Q7000 was \$190.1 million, including \$69.2 million paid to the shipyard upon signing the contract and the \$69.2 million shipyard invoice that was paid in October 2016 as agreed between the parties. We plan to incur approximately \$16 million of costs related to the construction of the Q7000 over the remainder of 2016.

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, the Siem Helix 1, which is expected to be in service for Petrobras in the fourth quarter of 2016, and the Siem Helix 2, which is expected to be in service in 2017. Our total investment in the topside equipment for both vessels is expected to be approximately \$260 million. We have invested \$179.5 million as of September 30, 2016 and plan to invest approximately \$23 million in the topside equipment over the remainder of 2016.

Financing Activities

Cash flows from financing activities consist primarily of proceeds from debt and equity financing activities and repayments of our long-term debt. Our \$250 million Nordea Q5000 Loan was funded in April 2015 at the time the Q5000 vessel was delivered to us. As of September 30, 2016, we had sold 13,018,732 shares of our common stock under our ATM programs for \$100 million, which generated net proceeds of \$96.5 million, including \$2.0 million that was received in October 2016. Repayments of our long-term debt increased by \$47.0 million during the nine-month period ended September 30, 2016 as compared to the same period in 2015 primarily reflecting an additional \$17.9 million in repayment of the Nordea Q5000 Loan, an additional \$15.5 million in repayment of the Term Loan and the payments to repurchase \$14.9 million of the 2032 Notes.

Outlook

We anticipate that our capital spending for fiscal year 2016, which includes capital expenditures as well as deferred dry dock costs and certain other deferred costs, will approximate \$220 million. We believe that our cash on hand, internally generated cash flows and availability under our Revolving Credit Facility if necessary will provide the capital necessary to continue funding our 2016 capital spending. Our estimate of future capital expenditures may change based on various economic factors. Beyond 2016, we may seek to reduce the level of our planned capital expenditures given a prolonged industry downturn.

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of September 30, 2016 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
Term Loan	\$224,500	\$28,968	\$195,532	\$—	\$—
Nordea Q5000 Loan	205,357	35,715	71,428	98,214	—
MARAD debt	83,222	6,222	13,390	14,760	48,850
2032 Notes ⁽²⁾	185,116	—	—	—	185,116
Interest related to debt ⁽³⁾	158,711	30,138	38,805	19,723	70,045
Property and equipment ⁽⁴⁾	330,916	122,344	208,572	—	—
Operating leases ⁽⁵⁾	875,177	150,614	292,051	227,163	205,349
Total cash obligations	\$2,062,999	\$374,001	\$819,778	\$359,860	\$509,360

Excludes unsecured letters of credit outstanding at September 30, 2016 totaling \$5.1 million. These letters of credit

(1) support various obligations, such as contractual obligations, customs duties, contract bidding and insurance activities.

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

(2) preceding fiscal quarter exceeds 130% of their issuance price on that 30th trading day (i.e., \$32.53 per share). At September 30, 2016, 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) Interest payment obligations were calculated using stated coupon rates for fixed rate debt and interest rates applicable at September 30, 2016 for variable rate debt.

(4) Primarily reflects the costs associated with our Q7000 semi-submersible vessel currently under construction and the topside equipment for the Siem Helix 2 chartered vessel (Note 12).

Operating leases include vessel charters and facility leases. At September 30, 2016, our vessel charter

(5) commitments totaled approximately \$827.9 million, including the Grand Canyon III that we expect to place in service in May 2017, the Siem Helix 1, which is expected to be in service for Petrobras in the fourth quarter of 2016, and the yet to be delivered Siem Helix 2.

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 2015 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 September 30, 2016, \$429.9 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 Q5000 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 \$1.4 million in interest expense for the nine-month period ended September 30, 2016.

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. In addition, a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the nine-month period ended September 30, 2016, we recognized gains of \$0.5 million related to foreign currency transactions in “Other income (expense), net” in our condensed consolidated statement of operations.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our results of operations and cash flows. As a result, we entered into various foreign currency exchange contracts to stabilize expected cash outflows related to certain vessel charters denominated in Norwegian kroner. 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. In December 2015, we re-designated the hedging relationship between a portion of our foreign currency exchange contracts and our forecasted Grand Canyon II and Grand Canyon III charter payments of NOK434.1 million and NOK185.2 million, respectively, that were expected to remain highly probable of occurring (Note 14). The foreign currency exchange contracts associated with the Grand Canyon charter payments and the re-designated contracts associated with the Grand Canyon II and Grand Canyon III charter payments currently qualify for cash flow hedge accounting treatment. For the nine-month period ended September 30, 2016, we recorded gains totaling \$0.1 million in “Other income (expense), net” related to foreign currency hedge ineffectiveness.

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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 Exchange Act, as of September 30, 2016. Based on this evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2016 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 September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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	(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 (1)
July 1 to July 31, 2016	—	\$	—	2,208,224
August 1 to August 31, 2016	—	—	—	2,208,224
September 1 to September 30, 2016	—	—	—	2,225,125
	—	\$	—	

Under the terms of our stock repurchase program, the issuance of shares to members of our Board 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 2015 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index on Page 49 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: October 21, 2016 By: /s/ Owen Kratz
Owen Kratz
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 21, 2016 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)
10.1	Equity Distribution Agreement dated August 11, 2016 between Helix Energy Solutions Group, Inc. and Wells Fargo Securities LLC.	Exhibit 1.1 to the Current Report on Form 8-K filed on August 11, 2016 (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