HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
April 25, 2012

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, 2012

or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from__________ to__________

Commission File Number 001-32936

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

Minnesota (State or other jurisdiction of incorporation or organization)	95–3409686 (I.R.S. Employer Identification No.)
400 North Sam Houston Parkway East Suite 400 Houston, Texas (Address of principal executive offices)	77060 (Zip Code)

(281) 618–0400
(Registrant's telephone number, including area code)

NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [√]	Accelerated filer [ ]	Non-accelerated filer [ ]

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

As of April 20, 2012, 105,641,054 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	March 31, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 620,449	$ 546,465
Accounts receivable-		
Trade, net of allowance for uncollectible accounts of $4,067	237,417	238,781
Unbilled revenue	15,458	24,338
Costs in excess of billing	9,118	13,037
Other current assets	109,669	121,621
Total current assets	992,111	944,242
Property and equipment	4,403,092	4,391,064
Less - accumulated depreciation	(2,041,405)	(2,059,737)
Property and equipment, net	2,361,687	2,331,327
Other assets:		
Equity investments	173,440	175,656
Goodwill	62,667	62,215
Other assets, net	75,038	68,907
Total assets	$ 3,664,943	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 145,631	$ 147,043
Accrued liabilities	196,814	239,963
Income tax payable	24,977	1,293
Current maturities of long-term debt	12,997	7,877
Total current liabilities	380,419	396,176
Long-term debt	1,167,486	1,147,444
Deferred income taxes	423,098	417,610
Asset retirement obligations	146,696	161,208
Other long-term liabilities	16,516	9,368
Total liabilities	2,134,215	2,131,806

Convertible preferred stock	1,000	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,636 and 105,530 shares issued, respectively	932,097	908,776
Retained Earnings	588,371	522,644
Accumulated other comprehensive loss	(19,667)	(10,017)
Total controlling interest shareholders' equity	1,500,801	1,421,403
Noncontrolling interest	28,927	28,138
Total equity	1,529,728	1,449,541
Total liabilities and shareholders' equity	$ 3,664,943	$ 3,582,347

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

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Net revenues:		
Contracting services	$229,842	$122,748
Oil and gas	178,085	168,859
Total net revenues	407,927	291,607
Cost of sales:		
Contracting services	156,968	106,907
Oil and gas	89,249	107,624
Total cost of sales	246,217	214,531
Gross profit	161,710	77,076
Gain (loss) on sale of assets, net	(1,478)	16
Loss on oil and gas derivative commodity contracts	(2,339)	-
Selling, general and administrative expenses	(25,696)	(24,981)
Income from operations	132,197	52,111
Equity in earnings of investments	407	5,650
Net interest expense	(21,760)	(24,236)
Loss on early extinguishment of long term debt	(17,127)	-
Other income (expense), net	86	2,660
Income before income taxes	93,803	36,185
Provision for income taxes	27,277	9,550
Net income, including noncontrolling interests	66,526	26,635
Less net income applicable to noncontrolling interests	(789)	(768)
Net income applicable to Helix	65,737	25,867
Preferred stock dividends	(10)	(10)
Net income applicable to Helix common shareholders	$65,727	$25,857
Earnings per share of common stock:		
Basic	$0.62	$0.24
Diluted	$0.62	$0.24
Weighted average common shares outstanding:		
Basic	104,530	104,471
Diluted	104,989	104,903

Comprehensive income (Note 9)	$56,876	$18,183

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

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

	Three Months Ended March 31, 2012	2011
Cash flows from operating activities:		
Net income, including noncontrolling interests	$66,526	$26,635
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	72,492	92,143
Asset impairment charge and dry hole expense	143	-
Amortization of deferred financing costs	2,355	1,981
Stock compensation expense	1,838	2,953
Amortization of debt discount	1,611	2,207
Deferred income taxes	(2,673)	9,329
Excess tax benefit from stock-based compensation	340	969
Gain on investment in Cal Dive common stock	-	(753)
(Gain) loss on sale of assets, net	1,478	(16)
Loss on early extinguishment of debt	17,127	-
Unrealized loss (gain) and ineffectiveness on derivative contracts, net	2,453	(318)
Changes in operating assets and liabilities:		
Accounts receivable, net	11,526	(381)
Other current assets	15,360	18,869
Income tax payable	23,233	(2,338)
Accounts payable and accrued liabilities	(59,079)	(58,747)
Oil and gas asset retirement costs	(18,357)	(8,160)
Other noncurrent, net	(2,568)	692
Net cash provided by operating activities	133,805	85,065
Cash flows from investing activities:		
Capital expenditures	(101,744)	(34,488)
Distributions from equity investments, net	5,943	480
Proceeds from sale of Cal Dive common stock	-	3,588
Decrease in restricted cash	922	613
Net cash used in investing activities	(94,879)	(29,807)
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	(209,500)	-
Borrowings under revolving credit facility	100,000	-
Issuance of Convertible Senior Notes due 2032	200,000	-
Repurchase of Convertible Senior Notes due 2025	(143,945)	-
Proceeds from Term Loan A	100,000	-
Repayment of Term Loan	(750)	(1,082)
Repayment of MARAD borrowings	(2,409)	(2,294)
Deferred financing costs	(6,337)	-
Repurchases of common stock	(991)	(927)

Excess tax benefit from stock-based compensation	(340)	(969)
Exercise of stock options, net and other	381	(70)
Net cash provided by (used in) financing activities	36,109	(5,342)
Effect of exchange rate changes on cash and cash equivalents	(1,051)	(470)
Net increase in cash and cash equivalents	73,984	49,446
Cash and cash equivalents:		
Balance, beginning of year	546,465	391,085
Balance, end of period	$620,449	$440,531

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 Recent Accounting Standards

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

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and are consistent in all material respects with those applied in our 2011 Annual Report on Form 10-K ("2011 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. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations, and cash flows, as applicable. The operating results for the three-month period ended March 31, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. Our balance sheet as of December 31, 2011 included herein has been derived from the audited balance sheet as of December 31, 2011 included in our 2011 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 2011 Form 10-K.

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

In June 2011, the Financial Accounting Standards Board ("FASB") issued amendments to disclosure requirements for presentation of comprehensive income. This guidance, effective retrospectively for the interim and annual periods beginning on or after December 15, 2011, requires presentation of total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued an amendment that deferred the presentation of reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. The implementation of the amended accounting guidance did not have a material impact on our consolidated financial position or results of operations.

Note 2 – Company Overview

We are an international offshore energy company that provides development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in the Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our oil and gas operations are located in the Gulf of Mexico.

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Contracting Services Operations
We seek to provide services and methodologies which we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: well operations, robotics, subsea construction and production facilities. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services business primarily includes well operations, robotics and subsea construction activities. Our Production Facilities business includes our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub"), as well as our majority ownership of the Helix Producer I ("HP I") vessel. It also includes the Helix Fast Response System ("HFRS"), which includes our Q4000 and HP I vessels. 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 for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS be deployed in connection with a well control incident. The retainer fee for the HFRS became effective April 1, 2011.

Oil and Gas Operations
We began our oil and gas operations to achieve incremental returns, to expand our off-season utilization of our contracting services assets, and to provide a more efficient solution to offshore abandonment. We have evolved this business model to include not only mature oil and gas properties but also unproved and proved reserves yet to be explored and developed. This has led to the assembly of services that allows us to create value throughout the complete cycle of a reservoir, including exploration through development and managing and operating a field's production up to and through the field's eventual abandonment.

Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of March 31, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
	(in thousands)	
Other receivables	$ 4,771	$ 5,096
Prepaid insurance	6,637	12,701
Other prepaids	10,200	13,271
Spare parts inventory	16,614	18,066
Current deferred tax assets	44,442	41,449
Hedging assets	17,785	21,579
Gas and oil imbalance	4,175	5,134
Other	5,045	4,325
Total other current assets	$ 109,669	$ 121,621

Other assets, net, consisted of the following as of March 31, 2012 and December 31, 2011:

	March 31,	December 31,

	2012	2011
	(in thousands)	
Restricted cash	$ 32,819	$ 33,741
Deferred drydock expenses, net	9,445	5,381
Deferred financing costs, net	28,081	26,483
Intangible assets with finite lives, net	520	531
Other	4,173	2,771
Total other assets, net	$ 75,038	$ 68,907

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Accrued liabilities consisted of the following as of March 31, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
	(in thousands)	
Accrued payroll and related benefits	$ 37,489	$ 49,599
Royalties payable	16,011	19,391
Current asset retirement obligations	82,339	93,183
Unearned revenue	7,724	7,654
Billing in excess of cost	8,361	28,839
Accrued interest	9,619	24,028
Hedging liability	15,167	1,247
Gas and oil imbalance	3,601	4,177
Other	16,503	11,845
Total accrued liabilities	$ 196,814	$ 239,963

Note 4 – Oil and Gas Properties

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are charged to expense in the period in which the drilling is determined to be unsuccessful.

Exploration and Other

As of March 31, 2012, we capitalized approximately $7.8 million of costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

The following table details the components of exploration expense for the three-month periods ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Delay rental and geological and geophysical costs	$ 611	$ 355
Impairment of unproved properties	144	–
Dry hole expense	(1)	(9)
Total exploration expense	$ 754	$ 346

Impairments

No proved property impairments were recorded in the first quarter of 2012 or 2011.

Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2011 (in thousands):

Asset retirement obligations at December 31, 2011	$ 254,391
Liability incurred during the period	115
Liability settled during the period	(34,665)
Other revisions in estimated cash flows	5,755
Accretion expense (included in depreciation and amortization)	3,439
Asset retirement obligations at March 31, 2012	$ 229,035

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Note 5 – Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. We had restricted cash totaling $32.8 million at March 31, 2012 and $33.7 million at December 31, 2011, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement and may use the restricted cash for the future asset retirement costs of the field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

The following table provides supplemental cash flow information for the three-month periods ended March 31, 2012 and 2011 (in thousands):

	Three Months Ended March 31,	
	2012	2011
Interest paid, net of capitalized interest(1)	$ 32,554	$ 32,093
Income taxes paid	$ 6,725	$ 3,785

Non-cash investing activities for the three-month periods ended March 31, 2012 and 2011 included $21.0 million and $36.0 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the accompanying condensed consolidated balance sheets as an increase in property and equipment and accounts payable.

Note 6 – Equity Investments

As of March 31, 2012, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (”Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $95.1 million and $96.0 million as of March 31, 2012 and December 31, 2011, respectively (including capitalized interest of $1.4 million at March 31, 2012 and December 31, 2011). Our net distributions from Deepwater Gateway totaled $2.2 million in the first quarter of 2012.

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. First production through the facility commenced in July 2007. Our investment in Independence Hub was $78.3 million and $79.7 million as of March 31, 2012 and December 31, 2011, respectively (including capitalized interest of $4.8 million and $4.9 million at March 31, 2012 and December 31, 2011, respectively). Our net distributions from Independence Hub totaled $4.2 million in the first quarter of 2012.

As disclosed in our 2011 Form 10-K, we invested in an Australian joint venture that engages in well intervention operations in the Southeast Asia region. At December 31, 2011, we fully impaired our investment in that joint venture (Note 7 of 2011 Form 10-K). In the first quarter of 2012, we recorded additional losses totaling $3.8 million related to our continued participation in this joint venture, including a $3.0 million negotiated exit fee from the joint venture. In April 2012, we paid this exit fee and we are no longer a participant in this Australian joint venture.

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Note 7 – Long-Term Debt

Scheduled maturities of long-term debt outstanding as of March 31, 2012 were as follows (in thousands):

	Term Loan (1)	Revolving Credit Facility	Senior Unsecured Notes	2025 Notes (2)	MARAD Debt	2032 Notes (3)	Total
Less than one year	$ 8,000	$	$	$	$ 4,997	$	$ 12,997
One to two years	8,000				5,247		13,247
Two to three years	8,000				5,508		13,508
Three to four years	355,000	100,000	274,960		5,783		735,743
Four to five years					6,072		6,072
Over five years				157,830	80,149	200,000	437,979
Total debt	379,000	100,000	274,960	157,830	107,756	200,000	1,219,546
Current maturities	(8,000)				(4,997)		(12,997)
Long-term debt, less current maturities	$371,000	$ 100,000	$ 274,960	$ 157,830	$ 102,759	$ 200,000	$1,206,549
Unamortized debt discount (4)				(3,688)		(35,375)	(39,063)
Long-term debt	$371,000	$ 100,000	$ 274,960	$ 154,142	$ 102,759	$ 164,625	$1,167,486

(1) Amounts reflect both our Term Loan and new Term Loan A.

(2) Beginning in December 2012, the holders of these Convertible Senior Notes may require us to repurchase these notes or we may at our own option elect to repurchase notes. These notes will mature in March 2025.

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

(4) The notes will increase to their principal amount through accretion of non-cash interest charges through December 2012 for the Convertible Senior Notes due 2025 and March 2018 for the Convertible Senior Notes due 2032.

At March 31, 2012, unsecured letters of credit issued totaled approximately $46.2 million (see "Credit Agreement" below). These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, contractual performance, insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three-month periods ended March 31, 2012 and 2011:

Three Months Ended March 31,	
2012	2011
(in thousands)	

Interest expense	$ 22,809	$24,767
Interest income	(570)	(476)
Capitalized interest	(479)	(55)
Interest expense, net	$ 21,760	$24,236

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt see Note 9 of our 2011 Form 10-K.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors. At December 31, 2011, we had $475.0 million of Senior Unsecured Notes outstanding. Prior to stated maturity, after January 15, 2012, we may redeem all or a portion of the Senior Unsecured Notes, on not less than 30 days' nor more than 60 days' prior notice at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest, in any, thereon to the applicable redemption date.

Year	Redemption Price
2012	104.750%
2013	102.375%
2014 and thereafter	100.000%

In March 2012, we purchased a portion of these Senior Unsecured Notes that resulted in an early extinguishment of $200.0 million of our balance outstanding. In these transactions we paid an aggregate amount of $213.5 million, including $200.0 million in principal, $9.5 million in premium for the repurchased Senior Unsecured Notes and $4.0 million of accrued interest. We also recorded a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of the Senior Unsecured Notes. The loss on the early extinguishment of these related Senior Unsecured Notes totaled $11.5 million and is reflected as a component of "Loss on early extinguishment of long term debt" in the accompanying condensed consolidated statements of operations and comprehensive income.

Credit Agreement

In July 2006, we entered into a credit agreement (the "Credit Agreement") under which we borrowed $835 million in a term loan (the "Term Loan") and were able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The Credit Agreement has been amended six times, most recently in March 2012 , to address certain issues with regard to covenants, maturity and the borrowing limits under the Term Loans and Revolving Credit Facility. For additional information regarding the current terms of our credit facility see Note 9 of our 2011 Form 10-K.

On February 21, 2012, we entered into an amendment to our Credit Agreement. Under the terms of the amendment the participating lenders agree to loan us $100.0 million pursuant to a new term loan ("Term Loan A"). The terms of the new Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual payment of its principal balance. The Term Loan A was funded in late March 2012 and we used the borrowings under Term Loan A to repurchase a portion of our Senior Unsecured Notes.

The Term Loan currently bears interest either at the one-, two-, three- or six-month LIBOR at our election plus an applicable margin of between 2.25% and 3.5% depending on our consolidated leverage ratio. Our average interest rate on the Term Loan for the three-month periods ended March 31, 2012 and 2011 was approximately 4.0% and 3.0%, respectively, including the effects of our interest rate swaps (Note 16). Our Term Loan is currently scheduled to mature on July 1, 2015 but could be extended to July 1, 2016 if our Senior Unsecured Notes are fully repaid or refinanced by July 1, 2015.

As amended, our Revolving Credit Facility provides for $600 million in borrowing capacity. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. In late March 2012, we borrowed $100.0 million under our Revolving Credit Facility to repurchase a portion of our Senior Unsecured Notes. Accordingly, at March 31, 2012, we had $100.0 million drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $453.8 million, net of $46.2 million of letters of credit issued. There were no borrowings outstanding at December 31, 2011.

The Revolving Loans bear interest based on one-, two-, three- or six-month LIBOR rates or on Base Rates, at our election, plus an applicable margin. The margin ranges from 1.5% to 3.5%, depending on our consolidated leverage ratio. The average interest rate under the Revolving Credit Facility totaled 3.0% for the period in which we had borrowings outstanding during the three-month period ended March 31, 2012.

The Credit Agreement contains various covenants regarding, among other things, collateral, capital expenditures, investments, dispositions, indebtedness and financial performance that are customary for this type of financing and for companies in our industry.

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we may enter into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan, which extended to January 2012. In August 2011, we entered into additional two-year interest rate swap contracts to assist in stabilizing cash flows related to our interest payments from January 2012 through January 2014 (Note 16).

Convertible Senior Notes

In March 2005, we issued $300 million of our 3.25% Convertible Senior Notes at 100% of the principal amount to certain qualified institutional buyers (the "2025 Notes"). The 2025 Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment.

The 2025 Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the 2025 Notes. No conversion triggers were met during the three-month period ended March 31, 2012. The first dates for early redemption of the 2025 Notes are in December 2012, with the holders of the 2025 Notes being able to put them to us on December 15, 2012 and our being able to call the 2025 Notes at any time after December 20, 2012 (see Note 9 of our 2011 Form 10-K). To the extent we do not have long-term financing secured to cover such conversion and/or redemption, the 2025 Notes would be classified as a current liability in the accompanying consolidated balance sheet. As the holders have the option to require us to redeem the 2025 Notes on December 15, 2012, we assessed whether or not this indebtedness was required to be classified as a current liability at March 31, 2012 and concluded that it still qualified as a long term debt because a) we possess enough borrowing capacity under our Revolving Credit Facility (see "Credit Agreement" above) to settle the notes in full and b) it is our intent to utilize our Revolving Credit Facility borrowings or other alternative financing proceeds to settle our 2025 Notes, if and when the holders exercise their redemption option.

The remaining balance of our 2025 Notes was $157.8 million at March 31, 2012. In association with the issuance of additional Convertible Senior Notes (see "2032 Notes" below), we repurchased $142.2 million in aggregate principal of our 2025 Notes. In these repurchase transactions we paid an aggregate amount of $145.1 million, representing principal plus $1.8 million of premium and $1.1 million of accrued interest on these repurchased 2025 Notes. The loss on the early extinguishment of these related 2025 Notes totaled $5.6 million and is reflected as a component of "Loss on early extinguishment of long term debt" in the accompanying condensed consolidated statements of operations and comprehensive income. The loss on early extinguishment includes the acceleration of $3.5 million of related unamortized discounts associated with the 2025 Notes, the $1.8 million premium paid in connection with the repurchase of a portion of the 2025 Notes and a $0.3 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of these 2025 Notes.

The effective interest rate for the 2025 Notes is 6.6% after considering the effect of the accretion of the related debt discount that represented the equity component of the Convertible Notes at their inception.

Our average share price for the both the first quarter of 2012 and 2011 was below the $32.14 per share conversion price. As a result of our share price being lower than the $32.14 per share conversion price for these periods, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our 2025 Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued on conversion.

2032 Notes

In March 2012, we completed the public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032 (the "2032 Notes"). The net proceeds from the issuance of the 2032 Notes were $195.0 million, after deducting the underwriter's discounts and commissions and estimated offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of our 2025 Notes (see above), in separate, privately negotiated transactions, and intend to use the remaining net proceeds for other general corporate purposes, including the repayment of other indebtedness.

The registered 2032 Notes bear interest at a rate of 3.25% per annum, payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March 15, 2032, unless earlier converted, redeemed or repurchased by us. 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 of the 2032 Notes (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. The initial conversion price represents a conversion premium of 35.0% over the closing price of our common stock on March 6, 2012 of $18.53 per share.

Prior to March 20, 2018, the 2032 Notes will not be redeemable. On or after March 20, 2018, we may, at our option, 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 of the 2032 Notes to be redeemed plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. Holders 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.

In connection with the issuance of our 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting requirements. 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 that the holder 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.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 which is 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 25 years from such date. The MARAD Debt is collateralized by the Q4000, with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in 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 (February 2027).

Other

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 Notes, 2032 Notes and MARAD Debt agreements, we are required to comply with certain covenants, including the maintenance of minimum net worth, working capital and debt-to-equity requirements, and restrictions that limit our ability to incur certain types of additional indebtedness. As of March 31, 2012, we were in compliance with these covenants and restrictions.

Deferred financing costs of $28.1 million and $26.5 million are included in other assets, net as of March 31, 2012 and December 31, 2011, respectively, and are being amortized over the life of the respective financing agreements.

Note 8 – Income Taxes

The effective tax rate for the three-month period ended March 31, 2012 was 29.1% as compared to 26.4% for the three-month period ended March 31, 2011. The variance is primarily attributable to increased profitability in certain foreign jurisdictions with higher income tax rates.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

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Note 9 – Comprehensive Income and Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three-month periods ended March 31, 2012 and 2011 were as follows (in thousands):

	Three Months Ended March 31,	
	2012	2011
Net income, including noncontrolling interests	$ 66,526	$ 26,635
Other accumulated comprehensive income, net of tax		
Foreign currency translation gain	4,152	2,115
Unrealized loss on hedges, net	(13,802)	(10,567)
Total comprehensive income	$ 56,876	$ 18,183

The components of accumulated other comprehensive loss were as follows (in thousands):

	March 31, 2012	December 31, 2011
Cumulative foreign currency translation adjustment	$ (18,806)	$ (22,958)
Unrealized gain (loss) on hedges, net	(861)	12,941
Accumulated other comprehensive loss	$ (19,667)	$ (10,017)

Note 10 – Earnings Per Share

We have shares of restricted stock issued and outstanding, some of which remain subject to vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share (“EPS”) amounts under the two class method in periods in which we have earnings from continuing operations. 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 contractually 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 available to common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (Income) and denominator

(Shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying condensed consolidated statements of operations are as follows (in thousands):

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$ 65,727		$ 25,857	
Less: Undistributed net income allocable to participating securities	(677)		(338)	
Net income applicable to common shareholders	$ 65,050	104,530	$ 25,519	104,471

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	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share - Basic	$ 65,050	104,530	$ 25,519	104,471
Effect of dilutive securities:				
Stock options		98		71
Undistributed earnings reallocated to participating securities	3		1	
2025 Notes and 2032 Notes				
Convertible preferred stock	10	361	10	361
Net income per common share - Diluted	$ 65,063	104,989	$ 25,530	104,903

There were no diluted shares associated with our 2025 Convertible Senior Notes as the conversion price of $32.14 (and conversion trigger of $38.57 per share) was not met in either of the three-month periods ended March 31, 2012 and 2011. Also, no diluted shares were included for our 2032 Notes for the three-month period ended March 31, 2012 as the conversion price of $25.02 (and conversion trigger of $32.53 per share) was not met and we have the right to settle any such future conversions in cash at our sole discretion.

Note 11 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended (the "2005 Incentive Plan"). As of March 31, 2012, there were 401,642 shares available for grant under our 2005 Incentive Plan. There were no stock option grants in the three-month periods ended March 31, 2012 and 2011. During the three-month period ended March 31, 2012, the following grants of share-based awards (restricted shares, restricted stock units and performance share units) were made to executive officers, selected management employees and non-employee members of the board of directors under the 2005 incentive plan:

Date of Grant	Shares	Market Value Per Share	Vesting Period
January 3, 2012	537,973	$ 15.80	33% per year over three years
January 3, 2012	1,958	15.80	100% on January 1, 2014

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three-month period ended March 31, 2012, $1.8 million was recognized as compensation expense related to shared based awards as compared with $3.0 million during the three-month period ended March 31, 2011.

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long term cash based compensation to eligible employees. Under the terms of the 2009 LTI Plan, the majority of the cash awards are fixed sum amounts payable (the vesting period is five years for awards granted before January 1, 2012 and three years thereafter). However, some of the cash awards are indexed to our Company common stock and the payment amount at each vesting date will fluctuate based on the common stock's performance. This share-based component is considered a liability plan and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as appropriate.

The total awards made under the 2009 LTI Plan totaled \$4.2 million in 2012 and \$5.2 million in 2011. Total compensation expense under the 2009 LTI plan totaled \$2.4 million and \$3.0 million for the three-month periods ended March 31, 2012 and 2011, respectively. The liability balance under the 2009 LTI Plan was \$6.9 million at March 31, 2012 and \$9.9 million at December 31, 2011, including \$6.5 million at March 31, 2012 and \$8.5 million at December 31, 2011 associated with the variable portion of the 2009 LTI plan.

For more information regarding our stock-based compensation plans, including our 2009 LTI Plan see Note 12 of our 2011 Form 10-K.

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Note 12 – Business Segment Information

Our operations are conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable segments. As a result, our reportable segments consist of the following: Contracting Services, Production Facilities and Oil and Gas. Contracting Services operations include well operations, robotics and subsea construction. The Production Facilities segment includes our consolidated investment in the HP I and Kommandor LLC as well as our equity investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method of accounting.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. All material intercompany transactions between the segments have been eliminated.

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Revenues		
Contracting Services	$ 244,544	$ 131,537
Production Facilities	20,022	15,570
Oil and Gas	178,085	168,859
Intercompany elimination	(34,724)	(24,359)
Total	$ 407,927	$ 291,607
Income (loss) from operations		
Contracting Services	$ 59,124	$ 3,266
Production Facilities	10,049	5,956
Oil and Gas	76,942	53,240
Corporate	(10,898)	(10,441)
Intercompany elimination	(3,020)	90
Total	$ 132,197	$ 52,111
Equity in earnings of equity investments	$ 407	$ 5,650

	March 31, 2012	December 31, 2011
	(in thousands)	
Identifiable Assets		
Contracting Services	$ 2,128,639	$ 2,006,065
Production Facilities	534,155	534,776
Oil and Gas	1,002,149	1,041,506
Total	$ 3,664,943	$ 3,582,347

Intercompany segment revenues during the three-month periods ended March 31, 2012 and 2011 were as follows:

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Contracting Services	$ 23,201	$ 12,869
Production Facilities	11,523	11,490
Total	$ 34,724	$ 24,359

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Intercompany segment profits during the three-month periods ended March 31, 2012 and 2011 were as follows:

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Contracting Services	$ 3,064	$ (24)
Production Facilities	(44)	(66)
Total	$ 3,020	$ (90)

Note 13 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a deepwater Gulf of Mexico prospect, from a third party. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Production began in December 2003. Our payments to OKCD totaled $1.7 million and $2.3 million for the three-month periods ended March 31, 2012 and 2011, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 81% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees, who are required to maintain their employment status with Helix in order to retain such income participations.

Note 14 – Commitments and Contingencies

Commitments

In March 2012, we executed a shipyard contract for the construction of a newbuild semisubmersible well intervention vessel. This $385.5 million shipyard contract represents the majority of the expected costs associated with this new semisubmersible well intervention vessel. We made the first scheduled payment under the contract in the amount of $57.8 million on March 12, 2012. Under terms of this contract, payments will be made in fixed amounts on contractually scheduled dates.

Contingencies and Claims

We were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivables yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor, then arbitration in India remains a potential remedy. Based on a number of factors associated with the ongoing negotiations with the prime contractor, in 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable (see Notes 16 and 18 of our 2011 Form 10-K). However, at the time of this filing no final commercial resolution of this matter has been reached.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million for the tax years 2007, 2008, 2009 and 2010 related to a subsea construction and diving contract we entered into in December 2006 in India. The State claims we owe unpaid taxes related to products consumed by us during the period of the contract. We are of the opinion that the State has arbitrarily assessed this VAT tax and has no foundation for the assessment and believe that we have complied with all rules and regulations as relate to VAT in the State. We also believe that our position is supported by law and intend to vigorously defend our position. However, the ultimate outcome of this assessment and our potential liability from it, if any, cannot be determined at this time. If the current assessment is upheld, it may have a material negative effect on our consolidated results of operations while also impacting our financial position.

We are involved in various legal proceedings, primarily 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 15 – Fair Value Measurements

Certain of our financial assets and liabilities are measured and reported at fair value on a recurring basis as required under applicable accounting requirements. These requirements establish a hierarchy for inputs used in measuring fair value. The fair value is to be calculated based on assumptions that market participants would use in pricing assets and liabilities and not on assumptions specific to the entity. The statement requires that each asset and liability carried at fair value be classified into one of the following categories:

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

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

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at March 31, 2012 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Natural gas contracts	$–	$20,239	$–	$20,239	(c)
Interest rate swaps	–	83	–	83	(c)
Foreign currency forwards	–	110	–	110	(c)
Liabilities:					
Oil contracts	–	23,647	–	23,647	(c)
Fair value of long term debt(2)	1,143,077	119,609	–	1,262,686	(a), (b)
Interest rate swaps	–	338	–	338	(c)
Foreign currency forwards	–	13	–	13	(c)
Total net liability	$1,143,077	$123,175	$–	$1,266,252	

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

(2) See Note 7 for additional information regarding our long term debt. The fair value of our long term debt at March 31, 2012 is as follows:

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	Fair Value	Carrying Value	
Term Loans (mature July 2015)	$ 380,395	$ 379,000	
Revolving Credit Facility (matures July 2015)	100,000	100,000	
2025 Notes (mature March 2025)	160,099	157,830	(a)
2032 Notes (mature March 2032)	212,500	200,000	(b)
Senior Unsecured Notes (mature January 2016)	290,083	274,960	
MARAD Debt (matures February 2027) (c)	119,609	107,756	
Total	$ 1,262,686	$ 1,219,546	

(a) Amount excludes the related unamortized debt discount of $3.7 million.

(b) Amount excludes the related unamortized debt discount of $35.4 million.

(c) The estimated fair value of all debt, other than the MARAD debt, was determined using Level 1 inputs using the market approach. The fair value of the MARAD debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other governmental obligations in the marketplace with similar terms. The fair value of the MARAD Debt was estimated using Level 2 fair value inputs using the market approach.

Note 16 – Derivative Instruments and Hedging Activities

We are currently exposed to market risk in three major areas: commodity prices, interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign exchange currency fluctuations. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value, unless otherwise noted.

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 derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income (loss), a component of shareholders' equity, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in fair value 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 20 of our 2011 Form 10-K.

Commodity Price Risks

We currently manage commodity price risk through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production for 2012 and 2013. All of our current commodity derivative contracts qualify for hedge accounting.

As of March 31, 2012, we had the following volumes under derivative contracts related to our oil and gas producing activities, totaling approximately 2.9 million barrels of oil and 14.4 Bcf of natural gas:

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Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price a
Crude Oil:			(per barrel)
April 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57b
April 2012 — December 2012	Collar	118.6 MBbl	$ 99.52 — $118.06
April 2012 — December 2012	Swap	11.4 MBbl	$103.20
January 2013 — December 2013	Swap	41.7 MBbl	$99.15
January 2013 — December 2013	Collar	50.0 MBbl	$ 95.83 — $105.50
Natural Gas:			(per Mcf)
April 2012 — December 2012	Swap	771.1 Mmcf	$4.32
April 2012 — December 2012	Collar	162.2 Mmcf	$4.75 — $5.09
January 2013 — December 2013	Swap	500.0 Mmcf	$4.09

a. The prices quoted in the table above are NYMEX Henry Hub for natural gas. Most of our current contracts are indexed to the Brent crude oil price.

b. This contract is priced using NYMEX West Texas Intermediate for crude oil.

In April 2012, we entered into costless collar financial derivative contracts associated with a total of 1.0 MMBbls of our anticipated crude oil production in 2013, with a floor price of $100.00 per barrel and a ceiling price of $122.06 per barrel as indexed to Brent crude oil prices.

Changes in NYMEX oil and gas and Brent crude oil strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX or Brent prices, respectively.

Variable Interest Rate Risks

As some of our long-term debt has variable interest rates and is subject to market influences, in January 2010 we entered into various interest rate swaps to stabilize cash flows relating to interest payments for $200 million of our Term Loan debt under our Credit Agreement (Note 7). The last of these monthly contracts matured in January 2012. In August 2011, we entered into additional interest rate swap contracts to fix the interest rate on $200 million of our Term Loan debt. These monthly contracts began in January 2012 and extend through January 2014. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled net interest expense. The amount of ineffectiveness associated with our interest swap contracts was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds. We did not designate any of our existing foreign exchange contracts as hedge contracts at their inception. The last of our existing monthly foreign currency swap contracts will settle in June

2012.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of March 31, 2012 and December 31, 2011.

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Derivatives designated as hedging instruments are as follows:

	As of March 31, 2012 Balance Sheet Location	As of March 31, 2012 Fair Value	As of December 31, 2011 Balance Sheet Location	As of December 31, 2011 Fair Value
Asset Derivatives:				
Natural gas contracts	Other current assets	$ 16,744	Other current assets	$ 12,957
Oil contracts	Other current assets	931	Other current assets	8,567
Natural gas contracts	Other assets	2,564	Other assets	857
Interest rate swaps	Other assets	83	Other assets	327
		$ 20,322		$ 22,708

	As of March 31, 2012 Balance Sheet Location	As of March 31, 2012 Fair Value	As of December 31, 2011 Balance Sheet Location	As of December 31, 2011 Fair Value
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 14,816	Accrued liabilities	$ 886
Interest rate swaps	Accrued liabilities	338	Accrued liabilities	202
Oil contracts	Other long-term liabilities	8,831	Other long-term liabilities	1,711
		$ 23,985		$ 2,799

Derivatives that were not designated as hedging instruments (in thousands):

	As of March 31, 2012 Balance Sheet Location	As of March 31, 2012 Fair Value	As of December 31, 2011 Balance Sheet Location	As of December 31, 2011 Fair Value
Asset Derivatives:				
Foreign exchange forwards	Other current assets	$ 110	Other current assets	$ 55
		$ 110		$ 55

	As of March 31, 2012 Balance Sheet Location	As of March 31, 2012 Fair Value	As of December 31, 2011 Balance Sheet Location	As of December 31, 2011 Fair Value
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	13	Accrued liabilities	159

	$ 13	$ 159

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our consolidated condensed statements of operations and comprehensive income for the three-month periods ended March 31, 2012 and 2011. The ineffectiveness related to some of our crude oil contracts totaled $2.3 million for the three-month period ended March 31, 2012 and is reflected as a separate line item titled "Loss on oil and gas derivative commodity contracts" in the accompanying condensed consolidated statements of operations and comprehensive income. Ineffectiveness associated with our interest swaps was immaterial for all periods presented in this report. All unrealized gains (losses) related to our derivative contracts are expected to be reclassified to earnings by no later than December 31, 2013. The last of our interest rate swaps will be settled in January 2014. At March 31, 2012, most of our remaining unrealized gains (losses) related to our derivative contracts are expected to be reclassified into earnings in 2012, including $2.8 million for our oil and natural gas contracts and $(0.2) million related to our interest swap contracts.

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	Gain (Loss) Recognized in Accumulated OCI on Derivatives	
	2012	2011
	(in thousands)	
Oil and natural gas commodity contracts	$ (13,555)	$ (10,778)
Interest rate swaps	(247)	211
	$ (13,802)	$ (10,567)

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Recognized from Accumulated OCI into Income 2012	2011
		(in thousands)	
Oil and natural gas commodity contracts	Oil and gas revenue	$ 109	$ (6,325)
Interest rate swaps	Net interest expense	(193)	(480)
		$ (84)	$ (6,805)

The following tables present the impact that derivative instruments not designated as hedges had on our condensed consolidated statement of operations for the three months ended March 31, 2012 and 2011:

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2012	2011
		(in thousands)	
Foreign exchange forwards	Other expense	233	608
		$ 233	$ 608

Note 17 – Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of our obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries (“Subsidiary Guarantors”) except for Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guaranty arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries’ cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries related primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)
(Unaudited)

	As of March 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 566,287	$ 2,498	$ 51,664	$ —	$ 620,449
Accounts receivable, net	50,886	118,038	68,493	—	237,417
Unbilled revenue	5,777	228	18,571	—	24,576
Income taxes receivable	86,005	—	1,586	(87,591)	—
Other current assets	54,484	45,654	9,864	(333)	109,669
Total current assets	763,439	166,418	150,178	(87,924)	992,111
Intercompany	(157,195)	340,018	(107,547)	(75,276)	—
Property and equipment, net	227,620	1,456,602	682,200	(4,735)	2,361,687
Other assets:					
Equity investments in unconsolidated affiliates	—	—	173,440	—	173,440
Equity investments	2,019,076	39,864	—	(2,058,940)	—
Goodwill	—	45,107	17,560	—	62,667
Other assets, net	54,828	36,566	21,475	(37,831)	75,038
Due from subsidiaries/parent	56,189	509,701	—	(565,890)	—
	$ 2,963,957	$ 2,594,276	$ 937,306	$ (2,830,596)	$ 3,664,943
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 42,316	$ 67,950	$ 35,365	$ —	$ 145,631
Accrued liabilities	68,627	107,284	20,903	—	196,814
Income taxes payable	—	128,808	—	(103,831)	24,977
Current maturities of long-term debt	8,000	—	4,997	—	12,997
Total current liabilities	118,943	304,042	61,265	(103,831)	380,419
Long-term debt	1,064,726	—	102,760	—	1,167,486
Deferred income taxes	234,567	90,526	103,861	(5,856)	423,098
	—	146,696	—	—	146,696

Asset retirement obligations					
Other long-term liabilities	4,163	11,803	550	—	16,516
Due to parent	—	—	89,821	(89,821)	—
Total liabilities	1,422,399	553,067	358,257	(199,508)	2,134,215
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,540,558	2,041,209	579,049	(2,631,088)	1,529,728
	$ 2,963,957	$ 2,594,276	$ 937,306	$ (2,830,596)	$ 3,664,943

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 495,484	$ 2,434	$ 48,547	$ —	$ 546,465
Accounts receivable, net	79,290	117,767	41,724	—	238,781
Unbilled revenue	10,530	155	26,690	—	37,375
Income taxes receivable	80,388	—	—	(80,388)	—
Other current assets	68,627	48,661	10,159	(5,826)	121,621
Total current assets	734,319	169,017	127,120	(86,214)	944,242
Intercompany	(147,187)	315,821	(102,826)	(65,808)	—
Property and equipment, net	230,946	1,422,326	682,899	(4,844)	2,331,327
Other assets:					
Equity investments in unconsolidated affiliates	—	—	175,656	—	175,656
Equity investments in affiliates	1,952,392	37,239	—	(1,989,631)	—
Goodwill, net	—	45,107	17,108	—	62,215
Other assets, net	53,425	36,453	16,809	(37,780)	68,907
Due from subsidiaries/parent	64,655	430,496	—	(495,151)	—
	$ 2,888,550	$ 2,456,459	$ 916,766	$ (2,679,428)	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 39,280	$ 82,750	$ 25,013	$ —	$ 147,043
Accrued liabilities	115,921	97,692	26,350	—	239,963
Income taxes payable	—	97,692	217	(96,616)	1,293
Current maturities of long-term debt	3,000	—	10,377	(5,500)	7,877
Total current liabilities	158,201	278,134	61,957	(102,116)	396,176
Long-term debt	1,042,155	—	105,289	—	1,147,444
Deferred income taxes	231,255	88,625	103,552	(5,822)	417,610
	—	161,208	—	—	161,208

Decommissioning liabilities					
Other long-term liabilities	4,150	4,647	571	—	9,368
Due to parent	—	—	98,285	(98,285)	—
Total liabilities	1,435,761	532,614	369,654	(206,223)	2,131,806
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,451,789	1,923,845	547,112	(2,473,205)	1,449,541
	$ 2,888,550	$ 2,456,459	$ 916,766	$ (2,679,428)	$ 3,582,347

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$20,022	$285,688	$ 125,900	$ (23,683)	$ 407,927
Cost of sales	16,621	164,593	88,445	(23,442)	246,217
Gross profit	3,401	121,095	37,455	(241)	161,710
Gain on sale or acquisition of assets	—	(1,478)	—	—	(1,478)
Loss on oil and gas derivative contract	—	(2,339)	—	—	(2,339)
Selling, general and administrative expenses	(11,272)	(9,877)	(4,834)	287	(25,696)
Income (loss) from operations	(7,871)	107,401	32,621	46	132,197
Equity in earnings of investments	93,250	2,625	407	(95,875)	407
Net interest expense and other	(30,547)	(7,210)	(1,044)	—	(38,801)
Income (loss) before income taxes	54,832	102,816	31,984	(95,829)	93,803
Provision (benefit) for income taxes	(10,874)	34,881	3,255	15	27,277
Net income (loss) applicable to Helix	65,706	67,935	28,729	(95,844)	66,526
Less: net income applicable to noncontrolling interests	—	—	—	(789)	(789)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$65,696	$67,935	$ 28,729	$ (96,633)	$ 65,727

	Three Months Ended March 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$15,582	$242,042	$ 57,876	$ (23,893)	$ 291,607
Cost of sales	16,593	165,231	56,278	(23,571)	214,531
Gross profit	(1,011)	76,811	1,598	(322)	77,076
Gain on sale or acquisition of assets	16	—	—	—	16
Selling, general and administrative expenses	(11,186)	(10,036)	(4,154)	395	(24,981)
Income (loss) from operations	(12,181)	66,775	(2,556)	73	52,111
Equity in earnings of investments	48,107	(5,662)	5,650	(42,445)	5,650
Net interest expense and other	(17,284)	(4,709)	417	—	(21,576)
Income (loss) before income taxes	18,642	56,404	3,511	(42,372)	36,185

Provision (benefit) for income taxes	(7,173)	21,741	(5,041)	23	9,550
Net income (loss) applicable to Helix	25,815	34,663	8,552	(42,395)	26,635
Less:net income applicable to noncontrolling interests	—	—	—	(768)	(768)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$25,805	$34,663	$ 8,552	$ (43,163)	$ 25,857

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 65,706	$ 67,935	$ 28,729	$ (95,844)	$ 66,526
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(93,250)	(2,625)	—	95,875	—
Other adjustments	15,685	68,889	(14,792)	(2,503)	67,279
Net cash provided by (used in) operating activities	(11,859)	134,199	13,937	(2,472)	133,805
Cash flows from investing activities:					
Capital expenditures	(896)	(94,640)	(6,208)	—	(101,744)
Distributions from equity investments, net	—	—	5,943	—	5,943
Decreases (increases) in restricted cash	—	922	—	—	922
Net cash used in investing activities	(896)	(93,718)	(265)	—	(94,879)
Cash flows from financing activities:					
Borrowings of debt	400,000	—	—	—	400,000
Repayments of debt	(354,195)	—	(2,409)	—	(356,604)
Deferred financing costs	(6,337)	—	—	—	(6,337)
Repurchases of common stock	(991)	—	—	—	(991)
Excess tax benefit from stock-based compensation	(340)	—	—	—	(340)
	381	—	—	—	381

Exercise of stock options, net and other					
Intercompany financing	45,040	(40,417)	(7,095)	2,472	—
Net cash provided by (used in) financing activities	83,558	(40,417)	(9,504)	2,472	36,109
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,051)	—	(1,051)
Net increase (decrease) in cash and cash equivalents	70,803	64	3,117	—	73,984
Cash and cash equivalents:					
Balance, beginning of year	495,484	2,434	48,547	—	546,465
Balance, end of year	$ 566,287	$ 2,498	$ 51,664	$ —	$ 620,449

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Three Months Ended March 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 25,815	$ 34,663	$ 8,552	$ (42,395)	$ 26,635
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(48,107)	5,662	—	42,445	—
Other adjustments	(16,484)	74,174	4,644	(3,904)	58,430
Net cash provided by (used in) operating activities	(38,776)	114,499	13,196	(3,854)	85,065
Cash flows from investing activities:					
Capital expenditures	(7,143)	(18,200)	(9,145)	—	(34,488)
Distributions from equity investments, net	—	—	480	—	480
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Decreases (increases) in restricted cash	—	613	—	—	613
Net cash used in investing activities	(3,555)	(17,587)	(8,665)	—	(29,807)
Cash flows from financing activities:					
Repayments of debt	(1,082)	—	(2,294)	—	(3,376)
Repurchases of common stock	(927)	—	—	—	(927)
Excess tax benefit from stock-based compensation	(969)	—	—	—	(969)
Exercise of stock options, net and other	590	—	(660)	—	(70)
Intercompany financing	93,799	(97,733)	80	3,854	—

Net cash provided by (used in) financing activities	91,411		(97,733)		(2,874)		3,854	(5,342)
Effect of exchange rate changes on cash and cash equivalents	—		—		(470)		—	(470)
Net increase (decrease) in cash and cash equivalents	49,080		(821)		1,187		—	49,446
Cash and cash equivalents:								
Balance, beginning of year	376,434		3,294		11,357		—	391,085
Balance, end of year	$425,514	$	2,473	$	12,544	$	— $	440,531

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

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

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

- statements regarding our business strategy, including the potential sale of assets and/or other investments in our subsidiaries and facilities, or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any oil and gas property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related hereto;
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

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

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- impact of the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- the effect of regulations on the offshore Gulf of Mexico oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;
- the effectiveness of our hedging activities;
- 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 and the terms of any such financing;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations, including exposure of our oil and gas operations to tropical storm activity in the Gulf of Mexico;
- the impact of operational disruptions affecting the Helix Producer I vessel which is crucial to producing oil and natural gas from our Phoenix field;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- 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 2011 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

Our Business

We are an international offshore energy company that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our oil and gas business is a prospect generation, exploration, development and production company. Employing our own key services and methodologies, we seek to lower finding and development costs, relative to industry norms.

Our Strategy

Over the past few years, we have focused on improving our balance sheet by increasing our liquidity through disposition of non-core business assets and reductions in our planned capital spending. At March 31, 2012, our cash on hand totaled $620.4 million and our liquidity was $1.1 billion. Our capital expenditures for full year 2012 are expected to total approximately $450 million, primarily reflecting construction costs associated with our recently announced new semi-submersible well intervention vessel and the exploration and development costs for certain of our oil and gas properties (excluding costs related to our asset retirement obligations). We believe that we have sufficient liquidity to successfully implement our business plan in 2012 without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Economic Outlook and Industry Influences

Demand for our contracting services operations 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. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. However, some of our Contracting Services, more specifically our subsea construction services, will often lag drilling operations by a period of 6 to 18 months, meaning that even if there were a sudden increase in deepwater permitting and subsequent drilling in the Gulf of Mexico, it probably would still be some time before we would start securing any awarded projects in this region. The performance of our oil and gas operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

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

Oil prices continue to strengthen in the first quarter from the elevated levels realized in the fourth quarter of 2011. The average NYMEX West Texas Intermediate ("WTI") crude oil price was $102.93 per barrel in the first quarter of 2012, $94.06 per barrel in the fourth quarter of 2011 and $94.10 per barrel in the first quarter of 2011. During the first quarter of 2011, the price that we received for the majority of our crude oil sales volumes started to increase significantly over the WTI market price. Historically the price we receive for most of our crude oil, as priced using a number of Gulf Coast crude oil price indexes, closely correlated with current market prices of WTI crude oil; however, because of a substantial increase in crude oil inventories at Cushing, Oklahoma the price of Gulf Coast crude is now substantially higher than WTI. Currently the price we receive for our crude oil more closely correlates with the Brent crude oil price in the North Sea. The premium we received for our oil sales was anywhere from $8-$27 per barrel greater than the given WTI price during the past twelve months and was approximately $11 per barrel in the first quarter of 2012. We do not know how long the price variance of our crude oil and WTI will continue but most analysts believe this premium will continue at least through 2012.

During the first quarter of 2012, the market environment for natural gas continued to deteriorate reflecting the unusually mild winter conditions for the majority of the U.S. and the continued increase in supply of natural gas derived primarily from non-traditional sources of natural gas such as production from shale formations and tight sands located throughout the U.S. A combination of these factors has decreased the NYMEX Henry Hub price of natural gas to approximately $2.15 per Mcf at March 31, 2012, reflecting the lowest prices for natural gas in approximately 10 years.

Although there have been signs that the economy is improving, most economists continue to believe the recovery will be slow and will take time to recover to levels previously achieved. The oil and natural gas industry has been adversely affected by the uncertainty of the general timing and level of the economic recovery as well the uncertainties concerning increased government regulation of the industry in the United States. Over the longer-term, the fundamentals for our business remain generally favorable as the need for the continual replenishment of oil and gas production is the primary driver of demand for our services.

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Helix Fast Response System

We developed the Helix Fast Response System ("HFRS") as a culmination of our experience as a responder in the Macondo oil spill response and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo oil spill response and containment efforts and are presently 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 for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS solution be deployed in connection with a well control incident. The retainer fee associated with HFRS was effective April 1, 2011 and is a component of our Production Facilities business segment.

RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two continuing reportable segments Contracting Services and Production Facilities. Our third business segment is Oil and Gas.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes well operations, robotics and subsea construction services. Our Contracting Services business operates primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. As of March 31, 2012, our Contracting Services had backlog of approximately $664.5 million, including $447.1 million expected to be performed over the remainder of 2012. Our Production Facilities segment reflects the results associated with the operations of the HP I as well as our equity investments in two Gulf of Mexico production facilities (Note 7). Backlog for the HP I totaled approximately $41.1 million at March 31, 2012, including $25.0 million expected to be serviced over the remainder of 2012. At December 31, 2011, our combined backlog for both Contracting Services and the HP I totaled $539.7 million, including $505.1 million for 2012. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

We began our oil and gas operations to achieve incremental returns, to expand off-season utilization of our Contracting Services assets, and to provide a more efficient solution to offshore abandonment. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage, and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

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Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as one that purports to measure historical or future performance, financial position, or cash flows, but excludes amounts that would not be so adjusted in the most comparable measures under generally accepted accounting principles (GAAP). We measure our operating performance based on EBITDAX, a non-GAAP financial measure, that is commonly used in the oil and natural gas industry but is not a recognized accounting term under GAAP. We use EBITDAX 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 under our debt covenants. We believe our measure of EBITDAX 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 EBITDAX as income (loss) from continuing operations plus income taxes, net interest expense and other, depreciation, depletion and amortization expense and exploration expenses. We separately disclose our non cash oil and gas property impairment charges, which, if not material, would be reflected as a component of our depreciation, depletion and amortization expense.

In our reconciliation of income, including noncontrolling interests, we provide amounts as reflected in our accompanying condensed consolidated financial statements unless otherwise footnoted. This means that such amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDAX, when applicable, we deduct the non-controlling interests related to the adjustment components of EBITDAX, the gain or loss on the sale of assets, unrealized gains (losses) associated with our oil and gas commodity contracts and the portion of our asset impairment charges that are considered cash-related charges. Asset impairment charges that are considered cash are those that affect future cash outflows most notably those related to adjustment to our asset retirement obligations.

Other companies may calculate their measures of EBITDAX and Adjusted EBITDAX differently than we do, which may limit its usefulness as a comparative measure. Because EBITDAX is not a financial measure calculated in accordance with GAAP, it should not be considered in isolation or as a substitute for net income attributable to common shareholders, but used as a supplement to that GAAP financial measure. A reconciliation of our net income attributable to common shareholders to EBITDAX is as follows:

	Three Months Ended March 31,	
	2012	2011
Net income, including noncontrolling interests	$ 66,526	$ 26,635
Adjustments:		
Income tax provision	27,277	9,550
Net interest expense and other	21,674	21,576
Loss on extinguishment of long term debt	17,127	—

Depreciation and amortization	72,492	92,143
Asset impairment charges	—	—
Exploration expenses	754	346
EBITDAX	205,850	150,250
Adjustments:		
Non-controlling interest in Kommandor LLC	(1,026)	(1,015)
Unrealized loss on oil and gas commodity contracts	2,339	—
Loss (gain) on sale of assets	1,478	(16)
ADJUSTED EBITDAX	$ 208,641	$ 149,219

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Comparison of Three Months Ended March 31, 2012 and 2011

The following table details various financial and operational highlights for the periods presented:

	Three Months Ended March 31, 2012	2011	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$244,544	$131,537	$ 113,007
Production Facilities	20,022	15,570	4,452
Oil and Gas	178,085	168,859	9,226
Intercompany elimination	(34,724)	(24,359)	(10,365)
	$407,927	$291,607	$ 116,320
Gross profit (in thousands) –			
Contracting Services	$ 66,512	$ 10,512	$ 56,000
Production Facilities	10,190	6,136	4,054
Oil and Gas	88,836	61,235	27,601
Corporate	(808)	(897)	89
Intercompany elimination	(3,020)	90	(3,110)
	$161,710	$ 77,076	$ 84,634
Gross Margin –			
Contracting Services	27%	8%	19 pts
Production Facilities	51%	39%	12 pts
Oil and Gas	50%	36%	14 pts
Total company	40%	26%	14 pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	9/93%	8/44%	
Well operations	3/84%	3/77%	
ROVs	47/68%	46/49%	

(1) Represents number of vessels 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.

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

Intercompany segment revenues during the three-month periods ended March 31, 2012 and 2011 were as follows (in thousands):

	Three Months Ended March 31,	Increase/

	2012	2011	(Decrease)
Contracting Services	$ 23,201	$ 12,869	$ 10,332
Production Facilities	11,523	11,490	33
	$ 34,724	$ 24,359	$ 10,365

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Intercompany segment profit during the three-month periods ended March 31, 2012 and 2011 was as follows (in thousands):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Increase/ (Decrease)
Contracting Services	$ 3,064	$ (24)	$ 3,088
Production Facilities	(44)	(66)	22
	$ 3,020	$ (90)	$ 3,110

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	1,426	1,501	(75)
Oil sales revenue (in thousands)	$155,744	$135,836	$ 19,908
Average oil sales price per Bbl (excluding hedges)	$ 111.61	$ 96.95	$ 14.66
Average realized oil price per Bbl (including hedges)	$ 109.18	$ 90.49	$ 18.69
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 28,060		
Change in production volume (in thousands)	(8,152)		
Total increase in oil sales revenue (in thousands)	$ 19,908		
Gas production volume (MMcf)	3,568	5,402	(1,834)
Gas sales revenue (in thousands)	$ 20,757	$ 31,161	$ (10,404)
Average gas sales price per mcf (excluding hedges)	$ 4.50	$ 5.14	$ (0.64)
Average realized gas price per mcf (including hedges)	$ 5.82	$ 5.77	$ 0.05
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 263		
Change in production volume (in thousands)	(10,667)		
Total decrease in gas sales revenue (in thousands)	$ (10,404)		
Total production (MBOE)	2,021	2,401	(380)
Price per BOE	$ 87.32	$ 69.54	$ 17.78
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$176,501	$166,997	$ 9,504
	1,584	1,862	(278)

Other revenues(1)			
	$178,085	$168,859	$ 9,226

(1) Other revenues include fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment on a cost per barrel of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. The following table highlights certain relevant expense items in total (in thousands) and on a cost per barrel of production basis (natural gas converted to barrel of oil equivalent at a ratio of six Mcf of natural gas to each barrel of oil):

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	Three Months Ended March 31, 2012		2011	
	Total	Per barrel	Total	Per barrel
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 28,566	$ 14.13	$ 30,660	$ 12.77
Workover	2,080	1.03	2,568	1.07
Transportation	1,857	0.92	2,411	1.00
Repairs and maintenance	1,870	0.93	2,267	0.94
Overhead and company labor	3,041	1.50	3,317	1.38
	$ 37,414	$ 18.51	$ 41,223	$ 17.16
Depletion expense	$ 44,404	$ 21.97	$ 65,713	$ 27.36
Abandonment	3,241	1.60	158	0.07
Accretion expense	3,439	1.70	3,786	1.58
Net hurricane (reimbursements) costs	(3)	—	(3,602)	(1.50)
Impairment	—	—	—	—
	51,081	25.27	66,055	27.51
Total	$ 88,495	$ 43.78	$ 107,278	$ 44.67

(1) Excludes exploration expense of $0.8 million and $0.3 million for the three-month periods ended March 31, 2012 and 2011, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. Our Contracting Services revenues increased by 86% for the three-month period ended March 31, 2012 as compared to the same period in 2011. The increase reflects significantly higher utilization for our subsea construction vessels, which benefited from an increase in activity in the Gulf of Mexico and the deployment of the Caesar on an accommodation project in Mexico. Our combined robotics and well operations revenues for the three-month period ended March 31, 2012 increased by 71% over amounts realized in the first quarter of 2011. The increase in our robotics revenues reflects the high utilization of our chartered vessels and owned ROVs, the utilization of a number of additional spot market vessels for much of the three-month period ended March 31, 2012, and the performance of a number of North Sea trenching projects even though such activities are not normally conducted during the first quarter in large part because of seasonal weather patterns. Our well operations activities reflected increased revenues despite our Q4000 semi-submersible vessel being in dry dock for the majority of March 2012. The Q4000 is expected to be back in service by end of April 2012. Our Seawell well intervention vessel also began its regulatory dry dock process in the second half of March 2012 and is expected to return to service in April 2012. The Intrepid is scheduled for a regulatory dry dock in the second quarter of 2012 and the Well Enhancer is expected to go into dry dock in the third quarter of 2012.

Oil and Gas revenues increased 5% during the three-month period ended March 31, 2012 as compared to the same period in 2011, reflecting higher oil prices. Our production decreased by 16% in the first quarter of 2012 as compared to the same period in 2011, primarily reflecting much lower natural gas production and normal oil production declines. For the month of April (through April 20, 2012) our production rate approximated 19.1 MBOE/d as compared to an approximate average of 22.2 MBOE/d in the first quarter of 2012.

Our Production Facilities revenues increased by 29% for the three-month period ended March 31, 2012 as compared to same period in 2011. The increase in revenues primarily reflects the quarterly HFRS retainer fee, which commenced on April 1, 2011. The HP I is currently being utilized in the Phoenix field, where it is expected to remain until the field depletes.

Gross Profit. Gross profit associated with our Contracting Services increased by over five-fold in the first quarter of 2012 as compared to the same period last year. This increase primarily reflects the much higher utilization of all of our vessels and ROVs. We expect our utilization rates will be lower in the second quarter of 2012 reflecting the regulatory dry dock inspections and repairs associated with three of our vessels (Q4000, Seawell and Intrepid). Absent scheduled dry dockings, we expect high utilization for our well operations and robotics vessels for the remainder of 2012.

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Oil and Gas gross profit increased by 45% in the first quarter of 2012 as compared to the same period in 2011, which was primarily attributable to higher oil price realizations. The decrease in our sales volumes was primarily related to lower natural gas production as a result of the disposition of eight of our non-operated properties (see below) and the shut in of the Noonan gas wells at the Bushwood field. We are also experiencing normal oil production declines at our Phoenix field.

Gain (Loss) on Sale of Assets, Net. The $1.5 million loss on the disposition of assets in the first quarter primarily reflects the disposition of eight of our non-operated oil and gas properties located in the Main Pass area of the Gulf of Mexico. We transferred our ownership interests in these natural gas producing properties to our joint interest partner in exchange for them assuming our share ($5.3 million) of the future asset retirement obligations associated with these properties.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses were essentially flat when comparing the year over year first quarter periods. However, as a percentage of revenues our selling general and administrative expenses decreased to 6.3% in the first quarter of 2012 as compared to 8.6% in the first quarter of 2011. In the first quarter of 2011, our selling, general and administrative expenses included $1.6 million of costs related to the resignation of our Executive Vice President and Chief Operating Officer.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $5.2 million during the three-month period ended March 31, 2012 as compared to the same prior year period. This decrease includes $3.8 million of losses associated with our Australian joint venture. We exited the Australian joint venture in April 2012. Separately, Independence Hub is now receiving lower fees following expiration of a five-year supplemental monthly demand fee that was paid by major customers of the facility. In the first quarter of 2011, we recorded $0.4 million of income for our 50% share of our Australia joint venture's income associated with its first contracted project located offshore China.

Net Interest Expense. Our net interest expense totaled $21.8 million for the three-month period ended March 31, 2012 as compared to $24.2 million in the same period last year. The decrease in interest expense primarily reflects a general reduction of our indebtedness since March 31, 2011, including the early extinguishment of approximately $275 million of our Senior Unsecured Notes since the end of the first quarter of 2011. Capitalized interest totaled $0.5 million for the three-month period ended March 31, 2012 as compared to $0.1 million for the same period in 2011. Interest income totaled $0.6 million for the first quarter of 2012 as compared with $0.5 million in the first quarter of 2011 primarily reflecting our increased cash balances.

Loss on early extinguishment of long term debt. In the first quarter of 2012, we recorded $17.1 million of charges related to the early extinguishment of portions of our debt, including $11.5 million related to our repurchase of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes (Note 7).

Other Income (Expense), net. We reported other income of $0.1 million in first quarter 2012 as compared to other income of $2.7 million in the same prior year period. In the first quarter of 2012, we recorded gains on our foreign exchange forward contracts totaling $0.2 million compared to gains of $0.6 million in the first quarter of 2011 (Note 16). In the first quarter of 2011, we also sold our remaining 0.5 million shares of Cal Dive common stock for net proceeds of approximately $3.6 million. Our gain on the sale of these remaining Cal Dive common shares was approximately $0.8 million.

Provision for Income Taxes. Income taxes reflected expense of $27.3 million in the first quarter of 2012 as compared to $9.6 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 29.1% for the first quarter of 2012 was higher than the 26.4% effective tax rate for the first quarter of 2011 as a result of the increased profititablity in certain foreign jurisdictions with higher income tax rates.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The following tables present certain information useful in the analysis of our financial condition and liquidity for the periods presented:

	March 31, 2012	December 31, 2011
	(in thousands)	
Net working capital	$ 611,692	$ 548,066
Long-term debt(1)	1,167,486	1,147,444
Liquidity(2)	1,074,250	1,105,065

(1) Long-term debt does not include the current maturities portion of the long-term debt as such amount is included in net working capital. It is also net of unamortized debt discount on our 2025 Notes and 2032 Notes (Note 7).
(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our revolving credit facility, which capacity is reduced by current letters of credit drawn against the facility.

The carrying amount of our debt, including current maturities as of March 31, 2012 and December 31, 2011 follow:

	March 31, 2012	December 31, 2011
	(in thousands)	
Term Loans (mature July 2015) (1)	$ 379,000	$ 279,750
Revolving Credit Facility (matures July 2015) (1)	100,000	
2025 Notes (mature March 2025) (2)	154,142	290,445
2032 Notes (mature March 2032) (3)	164,625	
Senior Unsecured Notes (mature January 2016)	274,960	474,960
MARAD Debt (matures February 2027)	107,756	110,166
Total	$ 1,180,483	$ 1,155,321

(1) Represents earliest date debt would mature; see Note 7 for conditions that would extend the maturity date.
(2) These amounts are net of the unamortized debt discount of $3.7 million and $9.6 million, respectively. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012. Notes may be redeemed by the holders beginning in December 2012 (Note 7).
(3) This amount is net of the unamortized debt discount of $35.4 million. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 2018.

The following table provides summary data from our consolidated statement of cash flows:

	Three Months Ended March 31, 2012	2011
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 133,805	$ 85,065

Investing activities	$ (94,879)	$ (29,807)
Financing activities	$ 36,109	$ (5,342)

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non-core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the hedged portion of our estimated oil and gas production through 2013. We believe that internally generated cash flow and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations throughout 2012. Separately, under certain circumstances or conditions, we may reduce our planned capital spending and seek further additional dispositions of our non-core business assets to the extent satisfactory economic opportunities exist.

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 Notes, 2032 Notes and MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage and consolidated indebtedness leverage, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. The Credit Agreement and Senior Unsecured Notes also contain 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 the Company. 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 loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences (or at least 60% of the proceeds from the disposition of certain assets). Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Term Loan A and the Revolving Credit Facility. As of March 31, 2012 and December 31, 2011, we were in compliance with all of our debt covenants and restrictions.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, such failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

Our 2025 Notes and 2032 Notes can be converted prior to stated maturity under certain triggering events specified in the respective indentures governing each series of Convertible Senior Notes. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2025 Notes and 2032 Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during the first quarter of 2012. The holders may redeem the 2025 Notes beginning December 2012 (Note 7 as well as Note 9 of our 2011 Form 10-K). As the holders have this option, we assessed whether or not this debt was required to be classified as a current liability at March 31, 2012 but concluded this debt still qualified as a long term debt because: a) we possess enough borrowing capacity under our Revolving Credit Facility (matures July 2015) to settle the Convertible Senior Notes in full and b) it is our intent to utilize our Revolving Credit Facility borrowing capacity or other alternative financing proceeds to settle our 2025 Notes, if and when the holders exercise their redemption option.

In June 2011, we amended our Credit Agreement to, among other things, extend its maturity to at least July 1, 2015 and increase the availability under our Revolving Credit Facility to $600 million. In February 2012, we entered into another amendment to our Credit Agreement. Under terms of this amendment, the lenders provided us $100 million in additional proceeds under a new term loan (Term Loan A). The terms of the new Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring $5 million annual amortization of the principal balance. The Term Loan A funded in late March 2012 and we used these proceeds and $100 million of borrowings under our Revolving Credit Facility to redeem $200 million of our Senior Unsecured Notes outstanding. See Note 7 as well as Note 9 of our 2011 Form 10-K for additional information related to our long-term debt, including more information regarding the recent amendments of our Credit Agreement and our requirements and obligations under the debt agreements including our covenants and collateral security.

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Working Capital

Cash flow from operating activities increased by $48.7 million in the three-month period ended March 31, 2012 as compared to the same period in 2011. This increase reflects our significantly increased level of Contracting Services activity and the effect of substantially higher oil prices in the first quarter of 2012.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, strategic acquisitions of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the three-month periods ended March 31, 2012 and 2011 were as follows:

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Capital expenditures:		
Contracting Services	$(82,238)	$ (15,016)
Production Facilities	(724)	(6,638)
Oil and Gas	(18,782)	(12,834)
Distributions from equity investments, net(1)	5,943	480
Sales of shares of Cal Dive common stock		3,588
Decrease in restricted cash	922	613
Cash used in investing activities	$(94,879)	$ (29,807)

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments are detailed in "Equity Investments" below.

Restricted Cash

As of March 31, 2012 and December 31, 2011, we had $32.8 million and $33.7 million of restricted cash, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied our escrow requirements and may use the restricted cash for the future asset retirement costs for this field. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

Equity Investments

We received the following distributions from our equity investments during the three-month periods ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
	2012	2011

	(in thousands)	
Deepwater Gateway.	$ 2,150	$ 1,750
Independence Hub	4,200	4,380
Total	$ 6,350	$ 6,130

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Outlook

We anticipate that capital expenditures for the remainder of 2012 will total between $340 million and $350 million. These estimates may increase or decrease based on various economic factors and/or existence of additional investment opportunities. However, we may reduce the level of our planned capital expenditures given any prolonged economic downturn or our inability to execute disposition transactions related to our remaining non-core business assets, most notably all or a portion of our oil and gas business assets. We believe internally generated cash flow, cash from future sales of our non-core business assets, and availability under our existing credit facilities will provide the capital necessary to fund our 2012 initiatives.

The following table summarizes our contractual cash obligations as of March 31, 2012 and the scheduled years in which the obligations are contractually due:

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
2025 Notes(2)	$ 157,830	$	$	$	$ 157,830
2032 Notes(3)	200,000				200,000
Senior Unsecured Notes	274,960			274,960	
Term Loans (4)	379,000	8,000	16,000	355,000	
MARAD debt	107,756	4,997	10,755	11,855	80,149
Revolving Credit Facility(5)	100,000			100,000	
Interest related to debt	433,078	64,297	125,314	57,862	185,605
Drilling and development costs	85,069	85,069			
Property and equipment (6)	354,975	85,500	269,475		
Operating leases(7)	162,794	69,700	45,308	41,460	6,326
Total cash obligations	$2,255,462	$ 317,563	$ 466,852	$ 841,137	$ 629,910

(1) Excludes unsecured letters of credit outstanding at March 31, 2012 totaling $46.2 million. These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2025 (2025 Notes can be redeemed by us or we may be required to purchase them beginning in December 2012). Notes can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e., $38.57 per share) and under certain triggering events as specified in the indenture governing the 2025 Notes. Upon the occurrence of a triggering event, to the extent we do not have alternative long-term financing secured to cover the conversion, the 2025 Notes would be classified as a current liability in the accompanying balance sheet. At March 31, 2012, the conversion trigger was not met.

(3)

Contractual maturity in 2032. The 2032 Notes have the same triggering mechanisms as noted in the 2025 Notes in (2) above except its issuance price is $25.02 per share and the stock price would have to exceed 130% of its issuance price on that 30th trading day ($32.53 per share). At March 31, 2012, the conversion trigger was not met. See Note 7 for additional information regarding these 2032 Notes.

(4) Our Term Loans will mature on July 1, 2015 but may extend to July 1, 2016 (January 1, 2016 with regards to Term Loan A) if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7).

(5) Our Revolving Credit Facility will mature on July 1, 2015 but may extend to January 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7).

(6) Primarily reflects the costs related to construction of our new semi-submersible well intervention vessel (Note 14).

(7) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at March 31, 2012 were approximately $151.3 million.

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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 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 2011 Form 10-K.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

We are currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Commodity Price Risk. As of March 31, 2012, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 2.9 million barrels of oil and 14.4 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price a
Crude Oil:			(per barrel)
April 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57b
April 2012 — December 2012	Collar	118.6 MBbl	$ 99.52 — $118.06
April 2012 — December 2012	Swap	11.4 MBbl	$103.20
January 2013 — December 2013	Swap	41.7 MBbl	$99.15
January 2013 — December 2013	Collar	50.0 MBbl	$ 95.83 — $105.50
Natural Gas:			(per Mcf)
April 2012 — December 2012	Swap	771.1 Mmcf	$4.32
April 2012 — December 2012	Collar	162.2 Mmcf	$4.75 — $5.09
January 2013 — December 2013	Swap	500.0 Mmcf	$4.09

a. The prices quoted in the table above are NYMEX Henry Hub for natural gas. Most of our current contracts are indexed to the Brent crude oil price.

b. This contract is priced using NYMEX West Texas Intermediate for crude oil.

In April 2012, we entered into costless collar financial derivative contracts associated with a total of 1.0 MMBbls of our anticipated crude oil production in 2013, with a floor price of $100.00 per barrel and a ceiling price of $122.06 per barrel as indexed to Brent crude oil prices.

Changes in NYMEX oil and gas and Brent crude oil strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX or Brent prices, respectively.

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, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended March 31, 2012. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended March 31, 2012 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.

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(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended March 31, 2012.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 14 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
January 1 to January 31, 2012(1)	60,486	$ 16.00		405,063(2)
February 1 to February 29, 2012(1)				
March 1 to March 31, 2012(1)	1,208	19.38		
	61,694	$ 16.06		

(1) Represents shares withheld to satisfy tax obligations arising upon the vesting of restricted shares.

(2) In January 2012, we issued this amount of share-based awards to certain of our employees (Note 11). Under the terms of our stock repurchase program, these grants increase the amount of shares available for repurchase. For additional information regarding our stock repurchase program see Note 14 of the 2011 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 44 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: April 25, 2012	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: April 25, 2012	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.

3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
4.1	Amendment No. 5 to Credit Agreement dated November 11, 2011 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 7, 2012.
4.2	Indenture dated as of March 12, 2012 between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee. Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by registrant with Securities and Exchange Commission on March 12, 2012.
10.1	Construction contract dated as of March 12, 2012 between Helix Energy Solution Group, Inc. and Jurong Shipyard Pte Ltd., incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant with the Securities and Exchange Commission on March 15, 2012.
15.1	Independent Registered Public Accounting Firm’s Acknowledgement Letter (1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer (1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer (1)
32.1	Certification of Helix’s Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes – Oxley Act of 2002 (2)
99.1	Report of Independent Registered Public Accounting Firm(1)
101.INS	XBRL Instance Document (2)
101.SCH	XBRL Schema Document (2)
101.CAL	XBRL Calculation Linkbase Document (2)
101.PRE	XBRL Presentation Linkbase Document (2)
101.DEF	XBRL Defininition Linkbase Document (2)
101.LAB	XBRL Label Linkbase Document (2)
	(1) Filed herewith
	(2) Furnished herewith