HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
July 24, 2013

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 June 30, 2013
or
[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from__________ to__________

Commission File Number 001-32936
HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

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

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

400 North Sam Houston Parkway East, Suite 400, Houston, Texas 77060
(Former address of principal executive offices)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [√] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [√] No [ ]

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [√]

As of July 19, 2013, 105,754,091 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 513,527	$ 437,100
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $4,000 and $5,152, respectively	163,486	152,233
Unbilled revenue	32,020	26,992
Costs in excess of billing	1,508	6,848
Other current assets	63,579	96,934
Current assets of discontinued operations	—	84,000
Total current assets	774,120	804,107
Property and equipment	1,858,537	2,051,796
Less accumulated depreciation	(432,170)	(565,921)
Property and equipment, net	1,426,367	1,485,875
Other assets:		
Equity investments	162,839	167,599
Goodwill	61,750	62,935
Other assets, net	49,673	49,837
Non-current assets of discontinued operations	—	816,227
Total assets	$ 2,474,749	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 91,836	$ 92,398
Accrued liabilities	100,091	161,514
Current maturities of long-term debt	5,247	16,607
Current liabilities of discontinued operations	—	182,527
Total current liabilities	197,174	453,046
Long-term debt	543,341	1,002,621
Deferred tax liabilities	288,596	359,237
Other non-current liabilities	19,838	5,025
Non-current liabilities of discontinued operations	—	147,237
Total liabilities	1,048,949	1,967,166
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,754 and 105,763 shares issued, respectively	932,899	932,742

Retained earnings	505,136	476,310
Accumulated other comprehensive loss	(37,797)	(15,667)
Total controlling interest shareholders' equity	1,400,238	1,393,385
Noncontrolling interest	25,562	26,029
Total equity	1,425,800	1,419,414
Total liabilities and shareholders' equity	$ 2,474,749	$ 3,386,580

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

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012
Net revenues	$232,178	$197,461
Cost of sales:		
Cost of sales	164,681	147,491
Impairments	—	21,532
Cost of sales	164,681	169,023
Gross profit	67,497	28,438
Loss on sale of assets	(1,085)	—
Selling, general and administrative expenses	(19,215)	(21,569)
Income from operations	47,197	6,869
Equity in earnings of investments	683	5,748
Net interest expense	(11,344)	(11,645)
Loss on early extinguishment of long-term debt	(646)	—
Other expense, net	(566)	(1,711)
Other income – oil and gas	1,282	—
Income before income taxes	36,606	(739)
Income tax provision (benefit)	8,577	(3,953)
Income from continuing operations	28,029	3,214
Income (loss) from discontinued operations, net of tax	(29)	42,216
Net income, including noncontrolling interests	28,000	45,430
Less net income applicable to noncontrolling interests	(789)	(789)
Net income applicable to Helix	$27,211	$44,641
Basic earnings per share of common stock:		
Continuing operations	$0.26	$0.02
Discontinued operations	0.00	0.40
Net income per common share	$0.26	$0.42
Diluted earnings per share of common stock:		
Continuing operations	$0.26	$0.02
Discontinued operations	0.00	0.40
Net income per common share	$0.26	$0.42
Weighted average common shares outstanding:		
Basic	105,046	104,563
Diluted	105,133	105,042

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

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net revenues	$429,607	$427,303
Cost of sales:		
Cost of sales	307,943	304,850
Impairments	1,600	21,532
Cost of sales	309,543	326,382
Gross profit	120,064	100,921
Loss on commodity derivative contracts	(14,113)	—
Loss on sale of assets	(1,085)	—
Selling, general and administrative expenses	(42,431)	(43,984)
Income from operations	62,435	56,937
Equity in earnings of investments	1,293	6,155
Net interest expense	(21,667)	(26,122)
Loss on early extinguishment of long-term debt	(3,528)	(17,127)
Other expense, net	(4,250)	(1,641)
Other income – oil and gas	4,100	—
Income before income taxes	38,383	18,202
Income tax provision (benefit)	9,020	(2,675)
Income from continuing operations	29,363	20,877
Income from discontinued operations, net of tax	1,029	91,069
Net income, including noncontrolling interests	30,392	111,946
Less net income applicable to noncontrolling interests	(1,566)	(1,578)
Net income applicable to Helix	$28,826	$110,368
Basic earnings per share of common stock:		
Continuing operations	$0.26	$0.18
Discontinued operations	0.01	0.87
Net income per common share	$0.27	$1.05
Diluted earnings per share of common stock:		
Continuing operations	$0.26	$0.18
Discontinued operations	0.01	0.87
Net income per common share	$0.27	$1.05
Weighted average common shares outstanding:		
Basic	105,039	104,547
Diluted	105,141	105,012

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

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012
Net income, including noncontrolling interests	$28,000	$45,430
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedges arising during the period	(5,882)	27,411
Reclassification adjustments for (gain) loss included in net income	354	(7,903)
Income taxes on unrealized (gain) loss on hedges	1,935	(6,828)
Unrealized gain (loss) on hedges, net of tax	(3,593)	12,680
Foreign currency translation loss	(218)	(2,838)
Other comprehensive loss, net of tax	(3,811)	9,842
Comprehensive income (loss)	24,189	55,272
Less comprehensive income applicable to noncontrolling interests	(789)	(789)
Comprehensive income (loss) applicable to Helix	$23,400	$54,483

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income, including noncontrolling interests	$30,392	$111,946
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedges arising during the period	(17,167)	6,093
Reclassification adjustments for (gain) loss included in net income	504	(7,819)
Income taxes on unrealized loss on hedges	5,832	604
Unrealized loss on hedges, net of tax	(10,831)	(1,122)
Foreign currency translation gain (loss)	(11,299)	1,314
Other comprehensive loss, net of tax	(22,130)	192
Comprehensive income (loss)	8,262	112,138
Less comprehensive income applicable to noncontrolling interests	(1,566)	(1,578)
Comprehensive income (loss) applicable to Helix	$6,696	$110,560

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

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities:		
Net income, including noncontrolling interests	$30,392	$111,946
Adjustments to reconcile net income, including noncontrolling interests to net cash provided by operating activities:		
Income from discontinued operations	(1,029)	(91,069)
Depreciation and amortization	49,692	47,388
Asset impairment charge	—	14,590
Amortization of deferred financing costs	2,824	3,292
Stock-based compensation expense	5,473	3,658
Amortization of debt discount	2,557	4,776
Deferred income taxes	16,058	21,624
Excess tax from stock-based compensation	(383)	657
Loss on sale of assets	1,085	—
Loss on early extinguishment of debt	3,528	17,127
Unrealized loss and ineffectiveness on derivative contracts, net	638	149
Changes in operating assets and liabilities:		
Accounts receivable, net	(19,702)	64,420
Other current assets	15,479	(19,571)
Income tax payable	(56,454)	1,083
Accounts payable and accrued liabilities	(35,081)	(22,072)
Oil and gas asset retirement costs	(5,950)	(19,241)
Other noncurrent, net	(7,117)	(19,940)
Net cash provided by (used in) operating activities	2,010	118,817
Net cash provided by (used in) discontinued operations	(30,503)	102,203
Net cash provided by (used in) operating activities	(28,493)	221,020
Cash flows from investing activities:		
Capital expenditures	(102,383)	(115,779)
Distributions from equity investments, net	4,567	2,045
Proceeds from sale of assets	108,250	—
Net cash provided by (used in) investing activities	10,434	(113,734)
Net cash provided by (used in) discontinued operations	582,965	(31,668)
Net cash provided by (used in) investing activities	593,399	(145,402)
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	—	(209,500)
Borrowings under revolving credit facility	47,617	100,000
Repayment of revolving credit facility	(147,617)	—
Issuance of Convertible Senior Notes due 2032	—	200,000
Repurchase of Convertible Senior Notes due 2025	(3,487)	(143,945)
Proceeds from term loan	—	100,000

Repayment of term loans	(367,181)	(2,750)
Repayment of MARAD borrowings	(2,529)	(2,409)
Deferred financing costs	(10,932)	(6,485)
Distributions to noncontrolling interest	(2,033)	—
Repurchases of common stock	(5,562)	(7,510)
Excess tax from stock-based compensation	383	(657)
Exercise of stock options, net and other	(186)	372
Net cash provided by (used in) financing activities	(491,527)	27,116
Effect of exchange rate changes on cash and cash equivalents	3,048	304
Net increase in cash and cash equivalents	76,427	103,038
Cash and cash equivalents:		
Balance, beginning of year	437,100	546,465
Balance, end of period	$513,527	$649,503

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

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles (“U.S. GAAP”) and are consistent in all material respects with those applied in our 2012 Annual Report on Form 10-K (“2012 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, statements of operations, statements of comprehensive income (loss), and statements of cash flows, as applicable. The operating results for the three- and six-month periods ended June 30, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. Our balance sheet as of December 31, 2012 included herein has been derived from the audited balance sheet as of December 31, 2012 included in our 2012 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 2012 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. The most significant of these reclassifications are associated with our discontinued operations. As noted in Note 2, we exited our oil and gas business in February 2013 upon the sale of our former wholly-owned subsidiary, Energy Resource Technology GOM, Inc. (“ERT”).

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (“ASU 2013-02”). ASU 2013-02 requires companies to provide information about the amounts that are reclassified out of accumulated other comprehensive income either by the respective line items of net income or by cross-reference to other required disclosures. This guidance is effective prospectively for fiscal years beginning after December 15, 2012. We adopted ASU 2013-02 on January 1, 2013. The adoption of this guidance did not have any material impact on our consolidated financial statements. We have presented the information required by the guidance in Note 16.

Note 2 — Company Overview

Contracting Services Operations

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on growing our well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: well intervention, 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 segment includes well intervention, robotics and subsea construction operations (see below for disclosure regarding the dispositions of our remaining subsea construction vessels and related assets). Our Production Facilities business includes our majority ownership of the Helix Producer I ("HP I") vessel as well as our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") (Note 6). It also includes the Helix Fast Response System ("HFRS"), which includes access to our Q4000 and HP I vessels.

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In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Caesar and Express, and other related pipelay equipment for a total sales price of $238.3 million. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million which included $30 million of funds deposited with us at the time the agreement was entered into (Note 3). We used $80.1 million of the after-tax proceeds from the sale of the Caesar to reduce our indebtedness under our former credit agreement (Note 7) and we are investing the remainder in our continuing operations, including supporting the expansion of our well intervention and robotics operations. This sale resulted in a loss of $1.1 million that is reflected in “Loss on sale of assets” in the accompanying condensed consolidated statement of operations. In July 2013, we completed the sale of the Express for $100 million, including the remaining $20 million of deposited funds. A gain of approximately $15.5 million will be recorded on the sale of the Express in the third quarter of 2013. We also entered into an agreement to sell our spoolbase and adjoining property at Ingleside, Texas to the same group of companies that purchased the Caesar and Express. The facility and adjoining property is being leased to the purchaser during the second half of 2013 and the sale is expected to close in January 2014. The total sales price is $45 million, payable over 3.5 years. At the time the agreement was signed, we received a $5 million deposit which is only refundable under limited circumstances.

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $624 million plus consideration in the form of overriding royalty interests in ERT’s Wang well and certain other of its future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements. See Note 4 for additional information regarding our discontinued oil and gas operations and Note 7 regarding the use of a portion of the sale proceeds to reduce our indebtedness under our former credit agreement.

Note 3 — Details of Certain Accounts

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

	June 30, 2013	December 31, 2012
Other receivables	$ 1,810	$ 1,086
Prepaid insurance	351	11,999
Other prepaids	11,832	11,751
Spare parts inventory	4,694	2,480
Income tax receivable	158	14,201
Current deferred tax assets	35,533	43,942
Derivative assets	—	5,946
Other	9,201	5,529
Total other current assets	$ 63,579	$ 96,934

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

	June 30, 2013	December 31, 2012
Deferred dry dock expenses, net	$ 18,418	$ 22,704
Deferred financing costs, net	28,610	24,338

Intangible assets with finite lives, net		514		491
Other		2,131		2,304
Total other assets, net	$	49,673	$	49,837

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Accrued liabilities consist of the following (in thousands):

	June 30, 2013	December 31, 2012
Accrued payroll and related benefits	$ 37,346	$ 51,561
Current asset retirement obligations	2,739	2,898
Unearned revenue	8,326	6,137
Billing in excess of cost	2,126	6,445
Accrued interest	16,424	17,451
Derivative liability (Note 16)	2,376	16,266
Taxes payable excluding income tax payable	6,080	5,164
Pipelay assets sale deposit (Note 2)	20,000	50,000
Other	4,674	5,592
Total accrued liabilities	$ 100,091	$ 161,514

Note 4 — Oil and Gas Properties

Results of Discontinued Operations

The following summarized financial information relates to ERT, which is reported as “Income from discontinued operations, net of tax” in the accompanying condensed consolidated statements of operations:

	Periods Ended June 30,		
	Six Months 2013 (1)	Three Months 2012	Six Months 2012
Revenues	$ 48,847	$ 149,933	$ 328,018
Costs:			
Production (lifting) costs	16,017	40,247	77,269
Exploration expenses	3,514	1,092	1,846
Depreciation, depletion, amortization and accretion	1,226	39,730	87,572
Proved property impairment and abandonment	(152)	4,077	7,317
Loss on sale of oil and gas properties	—	236	1,714
Gain on commodity derivative contracts	—	(10,069)	(7,730)
Selling, general and administrative expenses	1,229	3,002	6,283
Net interest expense and other (2)	2,732	6,973	14,250
Total costs	24,566	85,288	188,521
Pretax income from discontinued operations	24,281	64,645	139,497
Income tax provision	8,499	22,429	48,428
Income from operations of discontinued operations	15,782	42,216	91,069
Loss on sale of business, net of tax	(14,753)	—	—
Income from discontinued operations, net of tax	$ 1,029	$ 42,216	$ 91,069

(1) Results for 2013 primarily reflect the operating results from January 1, 2013 through February 6, 2013 when ERT was sold. There were no material results of operations for ERT during the three-month period ended June 30, 2013.

(2)

Net interest expense of $2.7 million for the six-month period ended June 30, 2013, and $6.8 million and $14.0 million for the three- and six-month periods ended June 30, 2012, respectively, was allocated to ERT primarily based on interest associated with indebtedness directly attributed to the substantial oil and gas acquisition made in 2006. This includes interest related to debt required to be paid upon the disposition of ERT.

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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 three months or less. The following table provides supplemental cash flow information (in thousands):

	Six Months Ended June 30, 2013	2012
Interest paid, net of interest capitalized	$ 20,403	$ 39,259
Income taxes paid	$ 49,981	$ 23,054

Total non-cash investing activities for the six-month periods ended June 30, 2013 and 2012 included $10.7 million and $37.8 million, respectively, of accruals for property and equipment capital expenditures.

Note 6 — Equity Investments

As of June 30, 2013, 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 $88.5 million and $91.4 million as of June 30, 2013 and December 31, 2012, respectively (including capitalized interest of $1.3 million at June 30, 2013 and December 31, 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. Our investment in Independence Hub was $74.4 million and $76.2 million as of June 30, 2013 and December 31, 2012, respectively (including capitalized interest of $4.4 million and $4.6 million at June 30, 2013 and December 31, 2012, respectively).

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Deepwater Gateway	$2,000	$1,250	$3,500	$3,400
Independence Hub	1,200	600	2,360	4,800
Total	$3,200	$1,850	$5,860	$8,200

As disclosed in our 2012 Form 10-K, in the first quarter of 2012, we recorded losses totaling $3.8 million associated with our investment in an Australian joint venture, including a $3.0 million fee paid in connection with our exit from the joint venture. In April 2012, we paid this fee and received approximately $3.7 million of proceeds for our pro rata portion (50%) of the value of certain of the net assets on hand at the time of our exit. These proceeds were recorded as income in our equity in earnings in the accompanying condensed consolidated statements of operations. We are no longer a participant in this joint venture.

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Note 7 — Long-Term Debt

Scheduled maturities of long-term debt outstanding as of June 30, 2013 are as follows (in thousands):

	Senior Unsecured Notes (1)	MARAD Debt	2032 Notes (2)	Total
Less than one year	$—	$5,247	$—	$5,247
One to two years	—	5,508	—	5,508
Two to three years	274,960	5,783	—	280,743
Three to four years	—	6,072	—	6,072
Four to five years	—	6,375	—	6,375
Over five years	—	73,774	200,000	273,774
Total debt	274,960	102,759	200,000	577,719
Current maturities	—	(5,247)	—	(5,247)
Long-term debt, less current maturities	274,960	97,512	200,000	572,472
Unamortized debt discount (3)	—	—	(29,131)	(29,131)
Long-term debt	$274,960	$97,512	$170,869	$543,341

(1) In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013, and we redeemed these notes in full on that date. See Senior Unsecured Notes below for additional disclosures regarding the early extinguishment of this debt.

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

(3) The Convertible Senior Notes due 2032 will increase to their principal amount through accretion of non-cash interest charges through March 2018.

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt, see Note 7 of our 2012 Form 10-K.

Credit Agreement

In June 2013, we entered into a Credit Agreement (the "Credit Agreement") with a group of lenders pursuant to which we may borrow up to $300 million in a term loan (the "Term Loan") and may borrow revolving loans (the "Revolving Loans") under a revolving credit facility up to an outstanding amount of $600 million (the "Revolving Credit Facility"). The Revolving Credit Facility also permits us to obtain letters of credit up to the full amount of the Revolving Credit Facility. Subject to customary conditions, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. Upon closing of the Credit Agreement, we borrowed approximately $81.5 million under the Revolving Credit Facility to repay existing outstanding amounts under our former revolving credit facility, and to cover fees and expenses associated with the Credit Agreement. This borrowing was fully repaid as of June 30, 2013. In July 2013, we borrowed $300 million under the Term Loan in connection with the early redemption of our remaining $275 million Senior Unsecured Notes (see "Senior Unsecured Notes" below).

The Term Loan and the Revolving Loans (together, the "Loans") will, at our election, bear interest either in relation to Bank of America's base rate or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit

Agreement) will be base rate loans. The Term Loan currently bears interest at the LIBOR Rate plus 2.75%.

The Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00%. The Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans

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multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio provided for in the Credit Agreement. We also pay a fixed commitment fee of 0.5% on the unused portion of our Revolving Credit Facility. At June 30, 2013, our availability under the Revolving Credit Facility totaled $579.4 million, net of $20.6 million of letters of credit issued.

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

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the “Loan Documents”) include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries’ ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet minimum financial requirements of EBITDA (as defined in the Credit Agreement) to interest charges, and funded debt to EBITDA. We may designate one of our existing foreign subsidiaries, and any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the “Unrestricted Subsidiaries”), provided we meet certain liquidity requirements, in which case the EBITDA of the Unrestricted Subsidiaries is not included in the calculations of our financial covenants. Our obligations under the Credit Agreement are guaranteed by our domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited. Our obligations under the Credit Agreement, and of guarantors under their guarantee, are secured by most of our assets and assets of the guarantors and Canyon Offshore Limited, plus pledges of up to 2/3 of the shares of certain foreign subsidiaries.

Former Credit Agreement

Our former credit agreement also contained both term loan and revolving loan components within the credit facility. This credit agreement was scheduled to mature on July 1, 2015. As of March 31, 2013, the amount of our former term loan debt was $72.3 million, which reflected the repayment of $293.9 million with the after-tax proceeds from the sale of ERT in February 2013. Our former credit agreement also provided for $600 million in borrowing capacity under its revolving credit facility. We had $78.1 million drawn on the former revolving credit facility at March 31, 2013, which reflected the repayment of $24.5 million with the after-tax proceeds from the sale of ERT. In connection with the repayment of debt in February 2013, we recorded a $2.9 million charge to accelerate a pro rata portion of the deferred financing costs associated with our former term loan debt. This charge is reflected as a component of “Loss on early extinguishment of long-term debt” in the accompanying condensed consolidated statements of operations.

In June 2013, we fully repaid the remaining $70.3 million of outstanding indebtedness under our former credit agreement. Prior to that repayment, the principal amounts outstanding at March 31, 2013 were reduced by repayments of $80.1 million of the after-tax proceeds from the sale of the Caesar (Note 2) in June 2013. Following the repayment of indebtedness, our former credit agreement was terminated. In connection with the repayment and termination of our former credit agreement, we recorded a $0.6 million charge to accelerate the remaining deferred financings costs associated with our indebtedness under the term loan component of our former credit agreement. This charge is also a component of “Loss on early extinguishment of long-term debt” in the accompanying condensed consolidated statements of operations.

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Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (the "Senior Unsecured Notes"). Interest on the Senior Unsecured Notes was payable semi-annually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes were 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 were required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries were not guarantors of the notes. The Indenture governing the Senior Unsecured Notes provided that, prior to their stated maturity, we may redeem all or a portion of the Senior Unsecured Notes on no less than 30 days' and no 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 thereon, if any, to the applicable redemption date.

Year	Redemption Price
2013	102.375%
2014 and thereafter	100.000%

In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013. On that date, we paid $282.0 million to fully redeem the Senior Unsecured Notes, including $275.0 million with respect to the outstanding principal amount, $6.5 million of call premium and $0.5 million in accrued and unpaid interest. Our third-quarter 2013 results of operations will include a loss on early extinguishment of debt charge totaling $8.6 million, which reflects the $6.5 million call premium and $2.1 million to accelerate the remaining deferred financing costs associated with the original issuance of the Senior Unsecured Notes.

In March 2012, we purchased a portion of these Senior Unsecured Notes, which resulted in an early extinguishment of $200.0 million of our outstanding balance. For the purchase, we paid a total of $213.5 million, including $200.0 million in principal, a $9.5 million call premium and $4.0 million of accrued and unpaid interest. We also recorded a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes. The loss on this early extinguishment of these 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.

Convertible Senior Notes Due 2032

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 offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of the 2025 Notes (see below) in separate, privately negotiated transactions. The remaining net proceeds were used for general corporate purposes, including the repayment of other indebtedness.

The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March 15, 2032, unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount 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, which was $18.53 per share.

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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 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 (as defined in the governing indenture).

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

MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As 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).

Convertible Senior Notes Due 2025

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers (the "2025 Notes").

In March 2012, we repurchased $142.2 million in aggregate principal of the 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. The loss on the early extinguishment of the 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. The loss on early extinguishment includes the acceleration of $3.5 million of unamortized discount 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 the 2025 Notes. The remainder of the 2025 Notes was extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us by the holders in December 2012.

Other

In accordance with our Credit Agreement, Senior Unsecured 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 June 30, 2013, we were in compliance with these covenants and restrictions.

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

	June 30, 2013			December 31, 2012		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loans (mature July 2015) (1)	$ —	$ —	$ —	$ 15,318	$ (11,595)	$ 3,723
Revolving Credit Facility (matures July 2015) (1)	—	—	—	20,021	(12,466)	7,555
Term Loan (matures June 2018) (2)	3,630	—	3,630	—	—	—
Revolving Credit Facility (matures June 2018) (2)	13,261	—	13,261	—	—	—
2025 Notes (mature December 2025)	—	—	—	8,189	(8,189)	—
2032 Notes (mature March 2032)	3,759	(840)	2,919	4,251	(534)	3,717
Senior Unsecured Notes (mature January 2016) (3)	10,643	(8,551)	2,092	10,643	(8,252)	2,391
MARAD Debt (matures February 2027)	12,200	(5,492)	6,708	12,200	(5,248)	6,952
Total deferred financing costs	$ 43,493	$ (14,883)	$ 28,610	$ 70,622	$ (46,284)	$ 24,338

(1) Relates to the term loans and revolving credit facility under our former credit agreement, which was terminated in June 2013.

(2) Relates to amounts allocated to the Term Loan and Revolving Credit Facility under our new Credit Agreement, which was entered into in June 2013.

(3) In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013, and we redeemed these notes in full on that date. In July 2013, we recorded a charge of $2.1 million to accelerate the remaining deferred financing costs associated with the original issuance of this debt.

The following table details our interest expense and capitalized interest (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Interest expense (1)	$13,977	$12,696	$26,555	$27,940
Interest income	(316)	(53)	(632)	(341)
Capitalized interest	(2,317)	(998)	(4,256)	(1,477)
Interest expense, net	$11,344	$11,645	$21,667	$26,122

(1) Interest expense of $2.8 million for the six-month period ended June 30, 2013, and $7.0 million and $14.6 million for the three- and six-month periods ended June 30, 2012, respectively, was allocated to ERT and is included in discontinued operations. We no longer allocate interest expense to ERT following the sale of ERT in February 2013.

Note 8 — Income Taxes

The effective tax rates for the three- and six-month periods ended June 30, 2013 were 23.4% and 23.5%, respectively. This was less favorable than the tax benefits recorded for the three- and six-month periods ended June 30, 2012. The variance is primarily attributable to projected year over year increases in profitability in the United States.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(10.6)	491.4	(11.1)	(47.5)
Other	(1.0)	8.5	(0.4)	(2.2)
Effective rate	23.4 %	534.9 %	23.5 %	(14.7) %

Note 9 — Accumulated Other Comprehensive Loss

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

	June 30, 2013	December 31, 2012
Cumulative foreign currency translation adjustment	$ (26,966)	$ (15,667)
Unrealized loss on hedges, net (1)	(10,831)	—
Accumulated other comprehensive loss	$ (37,797)	$ (15,667)

(1) Amount at June 30, 2013 is related to foreign currency hedges for the Grand Canyon, Grand Canyon II and Grand Canyon III, and is net of deferred income taxes totaling $5.8 million (Note 16).

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 applicable to Helix 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):

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	Three Months Ended June 30, 2013		Three Months Ended June 30, 2012	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 27,211		$ 44,641	
Less: (Income) loss from discontinued operations, net of tax	29		(42,216)	
Income from continuing operations	27,240		2,425	
Less: Undistributed income allocable to participating securities – continuing operations	(203)		(24)	
Income applicable to common shareholders – continuing operations	$ 27,037	105,046	$ 2,401	104,563
Discontinued operations:				
Income (loss) from discontinued operations, net of tax	$ (29)		$ 42,216	
Less: Undistributed income allocable to participating securities – discontinued operations	—		(424)	
Income (loss) applicable to common shareholders – discontinued operations	$ (29)	105,046	$ 41,792	104,563
Diluted:				
Continuing operations:				
Income applicable to common shareholders – continuing operations	$ 27,037	105,046	$ 2,401	104,563
Effect of dilutive securities:				
Share-based awards other than participating securities	—	87	—	118
Convertible preferred stock	—	—	10	361
Income applicable to common shareholders – continuing operations	$ 27,037	105,133	$ 2,411	105,042
Discontinued operations:				
Income from discontinued operations, net of tax	$ (29)	105,133	$ 42,216	105,042

	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 28,826		$ 110,368	
Less: Income from discontinued operations, net of tax	(1,029)		(91,069)	
Income from continuing operations	27,797		19,299	
Less: Undistributed income allocable to participating securities – continuing operations	(201)		(194)	
	$ 27,596	105,039	$ 19,105	104,547

Income applicable to common shareholders –
continuing operations

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	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
	Income	Shares	Income	Shares
Discontinued operations:				
Income from discontinued operations, net of tax	$ 1,029		$ 91,069	
Less: Undistributed income allocable to participating securities – discontinued operations	(7)		(917)	
Income applicable to common shareholders – discontinued operations	$ 1,022	105,039	$ 90,152	104,547
Diluted:				
Continuing operations:				
Income applicable to common shareholders – continuing operations	$27,596	105,039	$19,105	104,547
Effect of dilutive securities:				
Share-based awards other than participating securities	—	102	—	104
Undistributed income reallocated to participating securities	1	—	1	—
Convertible preferred stock	—	—	20	361
Income applicable to common shareholders – continuing operations	$27,597	105,141	$19,126	105,012
Discontinued operations:				
Income from discontinued operations, net of tax	$1,029	105,141	$91,069	105,012

No diluted shares were included for the 2032 Notes for the three- and six-month periods ended June 30, 2013 and 2012 as the conversion trigger of $32.53 per share was not met, and because we have the right to settle any such future conversions in cash at our sole discretion (Note 7).

Note 11 — Employee Benefit Plans

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 and restated effective May 9, 2012 (the “2005 Incentive Plan”). As of June 30, 2013, there were 6.5 million shares available for issuance under the 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options. There were no stock option grants in the three- and six-month periods ended June 30, 2013 and 2012. During the six-month period ended June 30, 2013, the following grants of share-based awards were made to executive officers and non-employee members of our Board of Directors under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2013 (1)	89,329	$ 20.64	33% per year over three years
January 2, 2013 (2)	89,329	30.96	100% on January 1, 2016
January 2, 2013 (3)	1,620	20.64	100% on January 1, 2015
April 1, 2013 (3)	2,814	22.88	100% on January 1, 2015

(1) Reflects the grant of restricted shares to our executive officers.

(2) Reflects the grant of performance share units ("PSUs") to our executive officers. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors elects to pay in cash.

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(3) Reflects the grant of restricted shares to certain members of our Board of Directors.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three- and six-month periods ended June 30, 2013, $1.9 million and $5.1 million, respectively, were recognized as stock-based compensation expense related to share-based awards as compared with $1.8 million and $3.7 million for the three- and six-month periods ended June 30, 2012. Additionally, for the first quarter of 2013, $1.3 million of stock-based compensation expense was reflected within our discontinued operations as a component of “Loss on sale of business, net of tax” (Note 4).

Long-Term Incentive Cash Plan

The 2005 Incentive Plan and the 2009 Long-Term Incentive Cash Plan (the “LTI Plans”) provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). These are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of our Board of Directors at the time of the award. Cash award payments under the LTI Plans are made each year on the anniversary date of the award. Cash awards granted prior to 2012 have a vesting period of five years and cash awards granted in 2012 and 2013 have a vesting period of three years. 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 deemed appropriate.

The cash awards made under the LTI Plans totaled $5.9 million in 2013 and $4.2 million in 2012. Such awards were made to our executive officers and selected management employees in 2013 and to our executive officers in 2012. No cash awards were given to non-executive employees in 2012. Total compensation expense associated with the cash awards issued pursuant to the LTI Plans was $1.7 million ($0.8 million related to our executive officers) and $4.2 million ($2.4 million related to our executive officers) for the three- and six-month periods ended June 30, 2013, respectively. For the three- and six-month periods ended June 30, 2012, total compensation expense associated with the cash awards issued pursuant to the LTI Plans was $1.2 million ($0.8 million related to our executive officers) and $3.6 million ($2.9 million related to our executive officers), respectively. The liability balance for the cash awards issued under the LTI Plans was $9.9 million at June 30, 2013 and $13.0 million at December 31, 2012, including $8.1 million at June 30, 2013 and $11.7 million at December 31, 2012 associated with the variable portion of the cash awards issued under the LTI plans.

Employee Stock Purchase Plan

In May 2012, our shareholders approved the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan (the “ESPP”). The ESPP has 1.5 million authorized shares of our common stock, of which 1.4 million shares were available for issuance as of June 30, 2013. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors and Section 423 of the Internal Revenue Code. The per share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The first purchase period under the ESPP began on September 1, 2012. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.2 million and $0.4 million for the three- and six-month periods ended June 30, 2013.

For more information regarding our employee benefit plans, including our stock-based compensation plans, our long-term incentive cash plan and our employee stock purchase plan, see Note 9 of our 2012 Form 10-K.

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Note 12 — Business Segment Information

In 2012, our operations were conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (see Note 2 for disclosures regarding the dispositions of our remaining subsea construction vessels and related assets). 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. All material intercompany transactions between the segments have been eliminated. In February 2013, we sold ERT and as a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements. See Note 4 for additional information regarding our discontinued operations.

We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. Certain financial data by reportable segment are summarized as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues —				
Contracting Services	$225,356	$209,557	$423,410	$454,101
Production Facilities	24,174	19,963	44,567	39,985
Intercompany elimination	(17,352)	(32,059)	(38,370)	(66,783)
Total	$232,178	$197,461	$429,607	$427,303
Income (loss) from operations —				
Contracting Services	$47,600	$19,223	$86,904	$78,347
Production Facilities	14,643	9,882	25,828	19,931
Corporate	(14,207)	(22,334)	(47,738)	(38,419)
Intercompany elimination	(839)	98	(2,559)	(2,922)
Total	$47,197	$6,869	$62,435	$56,937
Equity in earnings of equity investments	$683	$5,748	$1,293	$6,155

Intercompany segment revenues are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Contracting Services	17,352	20,538	$33,697	$43,739
Production Facilities	—	11,521	4,673	23,044
Total	$17,352	$32,059	$38,370	$66,783

Intercompany segment profits (losses) (which only relate to intercompany capital projects) are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Contracting Services	883	(55)	$2,647	$3,009
Production Facilities	(44)	(43)	(88)	(87)
Total	$839	$(98)	$2,559	$2,922

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Segment assets are comprised of all assets attributable to each reportable segment. The following table reflected total assets by reportable segment (in thousands):

	June 30, 2013	December 31, 2012
Contracting Services	$ 1,957,299	$ 1,974,763
Production Facilities	490,772	503,531
Corporate and Other	26,678	8,059
Discontinued Operations	—	900,227
Total	$ 2,474,749	$ 3,386,580

Note 13 — Related Party Transactions

In April 2000, ERT 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. ("OKCD"), the investors of which include current and former Helix management, in exchange for a revenue interest that is an overriding royalty interest of 25% of ERT's 20% working interest. Production began in December 2003. Payments to OKCD during the period in which Helix owned ERT totaled $0.6 million in the three-month period ended March 31, 2013, and $2.2 million and $3.9 million, respectively, in the three- and six-month periods ended June 30, 2012. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 84% of the partnership. Payments to OKCD by Helix ceased with the sale of ERT in February 2013, when the royalty agreement with OKCD was transferred to a third party along with ERT (and all of its assets and obligations).

Note 14 — Commitments and Contingencies and Other Matters

Commitments

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At June 30, 2013, our total investment in the Q5000 was $146.0 million, including $115.9 million of scheduled payments made to the shipyard.

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea well intervention operations. The vessel was delivered to us on April 1, 2013. The initial term of the charter will expire in March 2016.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. At June 30, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $164.6 million, including related well control equipment.

In January 2013, we contracted to charter the Rem Installer for use in our robotics operations. The term of the charter will be three years from the delivery date. The vessel was delivered to us in July 2013.

In February 2013, we contracted to charter the Grand Canyon II and Grand Canyon III for use in our robotics operations. The terms of the charters will be five years from the respective delivery dates, which are expected to be in 2014 and 2015.

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Contingencies and Claims

Under terms of the equity purchase agreement for the sale of ERT, we required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management ("BOEM") to cover the decommissioning costs of ERT's lease properties and thus to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. We further agreed in the equity purchase agreement that to the extent that the buyer is required to post bonding collateral in an amount greater than $100 million to obtain bonds in the aggregate amount required by the BOEM in order for the BOEM to release our guaranty of ERT's lease obligations, that we would provide incremental collateral above that amount, if and to the extent required, to the surety/ies providing bonding for ERT's deepwater properties (the Bushwood and Phoenix fields) in the form of letter(s) of credit, up to the next $50 million of required collateral, for a period not to exceed one year from issuance of the letter(s) of credit, after which the buyer would then be required to provide all collateral associated with the bonding requirements with respect to our former oil and gas properties. Because the collateral required for bonding the full amount of the current decommissioning assessments for ERT's lease properties did not exceed the $100 million threshold, we were not required to provide any collateral for the sureties to issue the requisite bonding.

In 2007, 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 a $4 million allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable ($17.5 million). 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 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. The State claims that 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 made these assessments and has no foundation for them. We believe that we have complied with all rules and regulations as related 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 these assessments and our potential liability from them, if any, cannot be determined at this time. If the current assessments are upheld, they may have a material negative effect on our consolidated results of operations while also impacting our financial position.

Litigation

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executives, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to the Company's then executive officers who are defendants. The Company filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on the Company's Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting

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similar causes of action arising out of the same facts as set forth in the federal action described above. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation. We filed motions to stay and dismiss the proceeding, which motions were denied by the trial court judge. We filed a petition for a writ of mandamus with the state appellate court, in which we requested that court to direct the district court to grant our motion to stay or dismiss the case. The appellate court has not ruled on our petition at the time of this filing.

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 other financial instruments measured at fair value on a recurring basis at June 30, 2013 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Liabilities:					
Fair value of long-term debt (2)	534,709	114,371	—	649,080	(a)
Foreign exchange contracts	—	17,155	—	17,155	(c)
Total liability	$ 534,709	$ 131,526	$ —	$ 666,235	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are

available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative.

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(2) See Note 7 for additional information regarding our long-term debt. The fair value of our debt is as follows:

	June 30, 2013	
	Carrying Value	Fair Value (c)
2032 Notes (mature March 2032) (a)	$ 200,000	$ 251,500
Senior Unsecured Notes (mature January 2016) (b)	274,960	283,209
MARAD Debt (matures February 2027)	102,759	114,371
Total debt	$ 577,719	$ 649,080

(a) Carrying value excludes the related unamortized debt discount of $29.1 million at June 30, 2013.

(b) In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013, and we redeemed these notes in full on that date.

(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

Our continuing operations are exposed to market risk associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value, 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 the hedges are effective. These fair value changes are recorded as a component of accumulated other comprehensive income or loss (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

For additional information regarding our accounting for derivatives, see Notes 2 and 17 of our 2012 Form 10-K.

Interest Rate Risk

We historically entered into interest rate swaps to stabilize cash flows related to our long-term debt subject to variable interest rates. We de-designated all of our interest rate swaps outstanding as hedging instruments in December 2012 following the announcement of the sale of ERT. We cash settled all outstanding interest rate swap contracts in February 2013. We had no debt outstanding with variable interest rates at June 30, 2013.

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds and Norwegian kroner.

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In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million), through September 2017. In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked-to-market each reporting period.

Quantitative Disclosures Related to Derivative Instruments

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our former credit agreement (Note 7), we were required to use a portion of the after-tax proceeds from the sales of ERT, the Caesar and Express to make payments to reduce our indebtedness. Because of the probability that the former term loan debt would be totally repaid before the expiration of our interest rate swaps, we also concluded that the swaps no longer qualified as cash flow hedges. In February 2013, we settled all of our outstanding commodity derivative contracts and interest rate swap contracts for approximately $22.5 million and $0.6 million, respectively.

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

	As of June 30, 2013			As of December 31, 2012		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Asset Derivatives:						
Oil contracts	Other current assets	$	—	Other current assets	$	5,800
Foreign exchange contracts	Other current assets		—	Other current assets		146
		$	—		$	5,946
Liability Derivatives:						
Oil contracts	Accrued liabilities	$	—	Accrued liabilities	$	15,777
Interest rate swaps	Accrued liabilities		—	Accrued liabilities		489
Foreign exchange contracts	Accrued liabilities		492	Accrued liabilities		—
Interest rate swaps	Other long-term liabilities		—	Other long-term liabilities		32
		$	492		$	16,298

As of June 30, 2013, our only derivative instruments designated as cash flow hedges were foreign currency exchange contracts related to the Grand Canyon, Grand Canyon II and Grand Canyon III charter payments. The fair value of these hedging instruments as of June 30, 2013 totaled $16.7 million, $1.9 million of which is reflected in "Accrued liabilities" and the remaining $14.8 million of which is reflected in "Other long-term liabilities" in the accompanying condensed consolidated balance sheet. The last of these contracts will settle in February 2020.

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Ineffectiveness associated with our foreign exchange contracts was immaterial for all periods presented. The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our condensed consolidated statements of operations (in thousands).

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Foreign exchange contracts	$(3,593)	$—	$(10,831)	$—
Oil and natural gas commodity contracts	—	12,759	—	(796)
Interest rate swaps	—	(79)	—	(326)
	$(3,593)	$12,680	$(10,831)	$(1,122)

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$ —	$ 8,023	$ —	$ 8,132
Interest rate swaps	Net interest expense	—	(120)	—	(313)
Foreign exchange contracts	Cost of sales	(354)	—	(504)	—
		$ (354)	$ 7,903	$ (504)	$ 7,819

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

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Oil and natural gas commodity contracts	Loss on commodity derivative contracts	$—	$—	$(14,113)	$—
Interest rate swaps	Other expense, net	—	—	(86)	—
Foreign exchange contracts	Other expense, net	53	(69)	(1,191)	164
		$53	$(69)	$(15,390)	$164

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

Prior to the redemption of the Senior Unsecured Notes on July 22, 2013, the payment of our obligations under these notes was 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 condensed consolidated financial statements and 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 as of June 30, 2013. The accompanying guarantor financial information is reported based 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 primarily relate to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of June 30, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$446,636	$3,082	$63,809	$ —	$ 513,527
Accounts receivable, net	65,060	42,017	56,409	—	163,486
Unbilled revenue	13,212	212	20,104	—	33,528
Income taxes receivable	8,164	—	4,662	(12,668)	158
Other current assets	41,951	4,142	17,285	43	63,421
Total current assets	575,023	49,453	162,269	(12,625)	774,120
Intercompany	45,778	189,357	(144,141)	(90,994)	—
Property and equipment, net	221,325	216,672	995,526	(7,156)	1,426,367
Other assets:					
Equity investments in unconsolidated affiliates	—	—	162,839	—	162,839
Equity investments in affiliates	957,181	48,253	—	(1,005,434)	—
Goodwill	—	45,107	16,643	—	61,750
Other assets, net	49,490	130	25,537	(25,484)	49,673
Due from subsidiaries/parent	336,287	—	—	(336,287)	—
Total assets	$2,185,084	$548,972	$1,218,673	$ (1,477,980)	$ 2,474,749
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$43,321	$22,205	$26,310	$ —	$ 91,836
Accrued liabilities	69,373	13,481	17,237	—	100,091
Income taxes payable	—	28,508	—	(28,508)	—
Current maturities of long-term debt	—	—	5,247	—	5,247
Total current liabilities	112,694	64,194	48,794	(28,508)	197,174
Long-term debt	445,828	—	97,513	—	543,341

Deferred tax liabilities	169,751	10,507	110,449	(2,111)	288,596
Other long-term liabilities	4,612	14,779	447	—	19,838
Due to parent	—	52,582	361,772	(414,354)	—
Total liabilities	732,885	142,062	618,975	(444,973)	1,048,949
Total equity	1,452,199	406,910	599,698	(1,033,007)	1,425,800
Total liabilities and shareholders' equity	$2,185,084	$548,972	$1,218,673	$ (1,477,980)	$ 2,474,749

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

	As of December 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 381,599	$ 4,436	$ 51,065	$ —	$ 437,100
Accounts receivable, net	39,203	37,378	75,652	—	152,233
Unbilled revenue	13,959	875	19,006	—	33,840
Income taxes receivable	24,611	—	306	(10,716)	14,201
Other current assets	54,588	16,418	11,696	31	82,733
Current assets of discontinued operations	—	84,000	—	—	84,000
Total current assets	513,960	143,107	157,725	(10,685)	804,107
Intercompany	(154,756)	352,210	(125,889)	(71,565)	—
Property and equipment, net	208,190	351,746	930,556	(4,617)	1,485,875
Other assets:					
Equity investments in unconsolidated affiliates	—	—	167,599	—	167,599
Equity investments in affiliates	1,762,359	53,461	—	(1,815,820)	—
Goodwill	—	45,107	17,828	—	62,935
Other assets, net	47,355	130	34,848	(32,496)	49,837
Due from subsidiaries/parent	294,461	485,096	—	(779,557)	—
Non-current assets of discontinued operations	—	816,227	—	—	816,227
Total assets	$ 2,671,569	$ 2,247,084	$ 1,182,667	$ (2,714,740)	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 45,784	$ 17,229	$ 29,385	$ —	$ 92,398
Accrued liabilities	117,902	26,019	17,593	—	161,514
Income taxes payable	—	26,618	—	(26,618)	—
Current maturities of long-term debt	11,487	—	5,120	—	16,607
Current liabilities of discontinued operations	—	182,527	—	—	182,527
Total current liabilities	175,173	252,393	52,098	(26,618)	453,046
Long-term debt	902,453	—	100,168	—	1,002,621
Deferred tax liabilities	168,688	86,925	109,171	(5,547)	359,237
Other long-term liabilities	1,453	3,086	486	—	5,025
Due to parent	—	—	323,049	(323,049)	—
Non-current liabilities of discontinued operations	—	147,237	—	—	147,237
Total liabilities	1,247,767	489,641	584,972	(355,214)	1,967,166
Total equity	1,423,802	1,757,443	597,695	(2,359,526)	1,419,414

Total liabilities and shareholders' equity	$ 2,671,569	$ 2,247,084	$ 1,182,667	$ (2,714,740)	$ 3,386,580

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
AND COMPREHENSIVE INCOME (LOSS)
(UNAUDITED)
(in thousands)

	Three Months Ended June 30, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$24,173	$114,268	$103,741	$ (10,004)	$ 232,178
Cost of sales	14,633	80,603	79,580	(10,135)	164,681
Gross profit	9,540	33,665	24,161	131	67,497
Loss on sale of assets	—	(1,085)	—	—	(1,085)
Selling, general and administrative expenses	(13,797)	(2,741)	(2,677)	—	(19,215)
Income (loss) from operations	(4,257)	29,839	21,484	131	47,197
Equity in earnings of investments	36,225	1,188	683	(37,413)	683
Net interest expense and other	(9,455)	(1,017)	(802)	—	(11,274)
Income (loss) before income taxes	22,513	30,010	21,365	(37,282)	36,606
Income tax provision (benefit)	(4,169)	10,776	2,396	(426)	8,577
Income (loss) from continuing operations	26,682	19,234	18,969	(36,856)	28,029
Loss from discontinued operations, net of tax	(29)	—	—	—	(29)
Net income (loss), including noncontrolling interest	26,653	19,234	18,969	(36,856)	28,000
Less net income applicable to noncontrolling interests	—	—	—	(789)	(789)
Net income (loss) applicable to Helix	$26,653	$19,234	$18,969	$ (37,645)	$ 27,211
Total comprehensive income (loss) applicable to Helix	$26,653	$15,641	$18,751	$ (37,645)	$ 23,400

	Three Months Ended June 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$19,963	$104,947	$95,632	$ (23,081)	$ 197,461
Cost of sales	26,084	93,291	72,509	(22,861)	169,023
Gross profit (loss)	(6,121)	11,656	23,123	(220)	28,438
Selling, general and administrative expenses	(11,658)	(5,917)	(4,257)	263	(21,569)
Income (loss) from operations	(17,779)	5,739	18,866	43	6,869
Equity in earnings of investments	64,446	3,670	5,748	(68,116)	5,748
Net interest expense and other	(9,607)	(101)	(3,648)	—	(13,356)
Income (loss) before income taxes	37,060	9,308	20,966	(68,073)	(739)
Income tax provision (benefit)	(7,554)	1,713	1,872	16	(3,953)
Income (loss) from continuing operations	44,614	7,595	19,094	(68,089)	3,214
	—	42,216	—	—	42,216

Income from discontinued operations, net of tax					
Net income (loss), including noncontrolling interest	44,614	49,811	19,094	(68,089)	45,430
Less net income applicable to noncontrolling interests	—	—	—	(789)	(789)
Net income (loss) applicable to Helix	$44,614	$49,811	$19,094	$ (68,878)	$ 44,641
Total comprehensive income (loss) applicable to Helix	$44,535	$62,570	$16,254	$ (68,876)	$ 54,483

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
AND COMPREHENSIVE INCOME (LOSS)
(UNAUDITED)
(in thousands)

	Six Months Ended June 30, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$44,567	$216,331	$194,867	$ (26,158)	$ 429,607
Cost of sales	31,222	154,973	149,680	(26,332)	309,543
Gross profit	13,345	61,358	45,187	174	120,064
Loss on sale of assets	—	(1,085)	—	—	(1,085)
Loss on commodity derivative contracts	(2,337)	(11,776)	—	—	(14,113)
Selling, general and administrative expenses	(29,587)	(6,650)	(6,194)	—	(42,431)
Income (loss) from operations	(18,579)	41,847	38,993	174	62,435
Equity in earnings of investments	69,371	(5,207)	1,293	(64,164)	1,293
Net interest expense and other	(18,235)	(2,166)	(4,944)	—	(25,345)
Income (loss) before income taxes	32,557	34,474	35,342	(63,990)	38,383
Income tax provision (benefit)	(10,437)	14,581	5,287	(411)	9,020
Income (loss) from continuing operations	42,994	19,893	30,055	(63,579)	29,363
Income (loss) from discontinued operations, net of tax	(14,753)	15,782	—	—	1,029
Net income (loss), including noncontrolling interest	28,241	35,675	30,055	(63,579)	30,392
Less net income applicable to noncontrolling interests	—	—	—	(1,566)	(1,566)
Net income (loss) applicable to Helix	$28,241	$35,675	$30,055	$ (65,145)	$ 28,826
Total comprehensive income (loss) applicable to Helix	$28,241	$24,844	$18,756	$ (65,145)	$ 6,696

	Six Months Ended June 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$39,985	$212,550	$221,532	$ (46,764)	$ 427,303
Cost of sales	42,705	169,026	160,954	(46,303)	326,382
Gross profit (loss)	(2,720)	43,524	60,578	(461)	100,921
Selling, general and administrative expenses	(22,930)	(12,513)	(9,091)	550	(43,984)
Income (loss) from operations	(25,650)	31,011	51,487	89	56,937
Equity in earnings of investments	157,696	6,295	6,155	(163,991)	6,155
Net interest expense and other	(40,164)	(34)	(4,692)	—	(44,890)
Income (loss) before income taxes	91,882	37,272	52,950	(163,902)	18,202
Income tax provision (benefit)	(18,428)	10,595	5,127	31	(2,675)

Income (loss) from continuing operations	110,310	26,677	47,823	(163,933)	20,877
Income from discontinued operations, net of tax	—	91,069	—	—	91,069
Net income (loss), including noncontrolling interest	110,310	117,746	47,823	(163,933)	111,946
Less net income applicable to noncontrolling interests	—	—	—	(1,578)	(1,578)
Net income (loss) applicable to Helix	$110,310	$117,746	$47,823	$ (165,511)	$ 110,368
Total comprehensive income (loss) applicable to Helix	$109,985	$116,950	$49,138	$ (165,513)	$ 110,560

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

	Six Months Ended June 30, 2013				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$28,241	$35,675	$30,055	$ (63,579)	$ 30,392
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(69,371)	5,207	—	64,164	—
Other adjustments	(35,513)	1,729	26,863	(21,461)	(28,382)
Cash provided by (used in) operating activities	(76,643)	42,611	56,918	(20,876)	2,010
Cash used in discontinued operations	—	(30,503)	—	—	(30,503)
Net cash provided by (used in) operating activities	(76,643)	12,108	56,918	(20,876)	(28,493)
Cash flows from investing activities:					
Capital expenditures	(3,545)	(19,000)	(79,838)	—	(102,383)
Distributions from equity investments, net	—	—	4,567	—	4,567
Proceeds from sale of assets	—	108,250	—	—	108,250
Cash provided by (used in) investing activities	(3,545)	89,250	(75,271)	—	10,434
Cash provided by discontinued operations	—	582,965	—	—	582,965
Net cash provided by (used in) investing activities	(3,545)	672,215	(75,271)	—	593,399
Cash flows from financing activities:					
Borrowings of debt	47,617	—	—	—	47,617
Repayments of debt	(518,285)	—	(2,529)	—	(520,814)
Deferred financing costs	(10,932)	—	—	—	(10,932)
Distributions to noncontrolling interests	—	—	(2,033)	—	(2,033)
Repurchases of common stock	(5,562)	—	—	—	(5,562)
Excess tax from stock-based compensation	383	—	—	—	383
Exercise of stock options, net and other	(186)	—	—	—	(186)
Intercompany financing	632,190	(685,677)	32,611	20,876	—
Net cash provided by (used in) financing activities	145,225	(685,677)	28,049	20,876	(491,527)
Effect of exchange rate changes on cash and cash equivalents	—	—	3,048	—	3,048
Net increase (decrease) in cash and cash equivalents	65,037	(1,354)	12,744	—	76,427

Cash and cash equivalents:					
Balance, beginning of year	381,599	4,436	51,065	—	437,100
Balance, end of period	446,636	3,082	63,809	—	513,527

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

	Six Months Ended June 30, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$110,310	$117,746	$47,823	$ (163,933)	$ 111,946
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(157,696)	(6,295)	—	163,991	—
Other adjustments	(23,616)	44,420	(11,702)	(2,231)	6,871
Cash provided by (used in) operating activities	(71,002)	155,871	36,121	(2,173)	118,817
Cash provided by discontinued operations	—	102,203	—	—	102,203
Net cash provided by (used in) operating activities	(71,002)	258,074	36,121	(2,173)	221,020
Cash flows from investing activities:					
Capital expenditures	(1,635)	(97,551)	(16,593)	—	(115,779)
Distributions from equity investments, net	—	—	2,045	—	2,045
Decreases in restricted cash	—	—	—	—	—
Cash used in investing activities	(1,635)	(97,551)	(14,548)	—	(113,734)
Cash used in discontinued operations	—	(31,668)	—	—	(31,668)
Net cash used in investing activities	(1,635)	(129,219)	(14,548)	—	(145,402)
Cash flows from financing activities:					
Borrowings of debt	400,000	—	—	—	400,000
Repayments of debt	(356,195)	—	(2,409)	—	(358,604)
Deferred financing costs	(6,485)	—	—	—	(6,485)
Repurchases of common stock	(7,510)	—	—	—	(7,510)
Excess tax from stock-based compensation	(657)	—	—	—	(657)
Exercise of stock options, net and other	372	—	—	—	372
Intercompany financing	131,741	(128,514)	(5,400)	2,173	—
Net cash provided by (used in) financing activities	161,266	(128,514)	(7,809)	2,173	27,116
Effect of exchange rate changes on cash and cash equivalents	—	—	304	—	304
Net increase in cash and cash equivalents	88,629	341	14,068	—	103,038
Cash and cash equivalents:					
Balance, beginning of year	495,484	2,434	48,547	—	546,465
Balance, end of period	584,113	2,775	62,615	—	649,503

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

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

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

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of the Q5000 and the upgrades to and modifications of the Helix 534 (Note 13);
- 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:

- impact of weak domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery to or chartering of new vessels for our well intervention and robotics fleet, including the Helix 534 (expected in the fourth quarter of 2013), the Q5000 (expected in 2015), the Grand Canyon II (expected in 2014) and the Grand Canyon III (expected in 2015);
- unexpected future capital expenditures (including the amount and nature thereof);
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;

- the effects of competition;
- 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 impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;

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- 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 2012 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 Strategy

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on growing our well intervention and robotics operations. We have focused on improving our balance sheet and increasing our liquidity since 2008 through dispositions of non-core business assets, related repayment of a significant portion of our indebtedness as well as the reduction in our capital spending through 2011. This goal was substantially accomplished with the sale of ERT in February 2013 and the recent sale of our two remaining pipelay vessels and related equipment. As such, we are now positioned for growth and expansion.

Our focus is to expand our Contracting Services capabilities by growing our well intervention and robotics operations. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We are strengthening our well intervention fleet by constructing a newbuild semi-submersible vessel, the Q5000, and by our acquisition of the Discoverer 534 drillship (renamed the Helix 534), which is currently undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. We have also chartered the Skandi Constructor, which is currently quayside undergoing its final preparations and modifications for use in our North Sea well intervention operations. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles (“ROVs”) and trenchers as well as taking delivery of a newbuild chartered ROV support vessel, the Grand Canyon. In 2013, we entered into charter agreements for two similar vessels, the Grand Canyon II and Grand Canyon III, which are expected to be delivered in 2014 and 2015, respectively. We also contracted to charter the Rem Installer, which was delivered to us in July 2013.

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. The performance of our 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 the Organization of the Petroleum Exporting Countries (“OPEC”);
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and 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;

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- environmental and other governmental regulations; and
- tax policies.

Despite strong financial market performances in recent months, the global economy may grow at a slower rate than many economists had previously forecasted for the remainder of 2013, weighed by modest recovery in mature markets and gradual slowdown in major emerging markets. The U.S. economy showed some positive signs in the second quarter of 2013 with steady job growth, especially in the private sector, and a modest increase in consumer confidence. The European economy remains weak despite stable financial market performances and some improvements in business and consumer confidence. The slowdown in many emerging economies is continuing. This is evidenced by the slower than expected growth in China over the first half of 2013. Weak economic data could affect the global equity and commodity markets as well as effectively hampering normal business activities. 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.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

Helix Fast Response System

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

RESULTS OF OPERATIONS

We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Previously, we had a third business segment, Oil and Gas. In December 2012, we announced a definitive agreement for the sale of ERT, which transaction closed in February 2013. Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Quarterly Report on Form 10-Q.

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 intervention, robotics and subsea construction operations (see Note 2 regarding the dispositions of our remaining subsea construction vessels and related assets). 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. In addition, our robotics operations are often contracted for the development of renewable energy projects (wind farms). Backlog contracts are cancelable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our contracting services operations as contracts may be added, cancelled and in many cases modified while in progress. As of June 30, 2013, our Contracting Services segment had backlog of approximately $1.8 billion, including $317.7 million expected to be performed over the remainder of 2013. In early April, we entered into a five-year contract with BP to provide well intervention services with our deepwater well intervention semi-submersible vessel, the Q5000, currently being constructed in Singapore.

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 6). In connection with the sale of ERT, a new fee arrangement for usage of the HP I at the Phoenix field was agreed upon with the new owner of ERT. Under the terms of this arrangement, ERT will pay us a lower fixed annual demand fee; however, ERT will also pay us a variable throughput fee. We anticipate that the total combined fees will approximate at least the previous fixed annual demand fee over the life of the contract. Currently, the fees being received exceed the previous fixed annual demand fee. The revised terms now also provide that the HP I will continue to provide service to ERT's Phoenix field through at least December 31, 2016.

Discontinued Operations

In February 2013, we sold ERT for $624 million plus consideration in the form of overriding royalty interests in ERT's Wang well and certain other of its future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements (Notes 2 and 4). The Wang well commenced production in late April 2013.

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

We define EBITDA as income from continuing operations plus income taxes, net interest expense and other and depreciation and amortization expense. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense.

In the following reconciliation, 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 EBITDA from continuing operations, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and if applicable, any gain or loss on the sale of assets from continuing operations.

We also provide a measure of Adjusted EBITDAX, which combines our measure of Adjusted EBITDA from continuing operations and the measure of Adjusted EBITDAX from discontinued operations. Our discontinued operations represent ERT which was sold in February 2013. We define Adjusted EBITDAX from discontinued operations as income from discontinued operations, net of tax (Note 4) plus income taxes, net interest expense and other, depreciation, depletion, amortization and accretion expense and exploration expenses.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income from continuing operations	$28,029	$3,214	$29,363	$20,877
Adjustments:				
Income tax provision (benefit)	8,577	(3,953)	9,020	(2,675)
Net interest expense and other	11,910	13,356	25,917	27,763
Loss on extinguishment of long-term debt	646	—	3,528	17,127
Depreciation and amortization	25,312	22,739	49,692	47,388
Asset impairment charges	—	14,590	—	14,590
EBITDA from continuing operations	74,474	49,946	117,520	125,070
Adjustments:				
Noncontrolling interest Kommandor LLC	(1,026)	(1,026)	(2,041)	(2,052)
Loss on sale of assets	1,085	—	1,085	—
ADJUSTED EBITDA from continuing operations	$74,533	$48,920	$116,564	$123,018
ADJUSTED EBITDA from continuing operations	$74,533	$48,920	$116,564	$123,018
ADJUSTED EBITDAX from discontinued operations (1)	—	102,606	31,754	237,149
ADJUSTED EBITDAX	$74,533	$151,526	$148,318	$360,167

(1) Amounts relate to ERT which was sold in February 2013 (Notes 2 and 4).

Comparison of Three Months Ended June 30, 2013 and 2012

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

	Three Months Ended June 30,		Increase/ (Decrease)
	2013	2012	
Revenues (in thousands) —			
Contracting Services	$225,356	$209,557	$15,799
Production Facilities	24,174	19,963	4,211
Intercompany elimination	(17,352)	(32,059)	14,707
	$232,178	$197,461	$34,717
Gross profit (in thousands) —			
Contracting Services	$54,283	$26,338	$27,945
Production Facilities	14,784	10,017	4,767
Corporate	(731)	(8,015)	7,284
Intercompany elimination	(839)	98	(937)
	$67,497	$28,438	$39,059

Gross Margin —				
Contracting Services	24	%	13	%
Production Facilities	61	%	50	%
Total company	29	%	14	%

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	Three Months Ended June 30, 2013		Three Months Ended June 30, 2012	
Number of vessels (1) / Utilization (2)				
Contracting Services:				
Construction vessels	5/97	%	9/84	%
Well operations	4/93	%	3/67	%
ROVs	55/61	%	51/65	%

(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 each category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues are as follows (in thousands):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase/ (Decrease)
Contracting Services	$17,352	$20,538	$(3,186)
Production Facilities	—	11,521	(11,521)
	$17,352	$32,059	$(14,707)

Intercompany segment profit is as follows (in thousands):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase/ (Decrease)
Contracting Services	$883	$(55)	$938
Production Facilities	(44)	(43)	(1)
	$839	$(98)	$937

In the following disclosures regarding our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. Our disclosures specifically refer to our Contracting Services and Production Facilities segments. Disclosures regarding our former Oil and Gas segment are presented under "Discontinued Operations — Oil and Gas" below and in Note 4.

Revenues. Our Contracting Services revenues increased by 8% for the three-month period ended June 30, 2013 as compared to the same period in 2012 reflecting significantly higher revenues associated with our well intervention vessels primarily attributable to the addition of the Skandi Constructor to the fleet effective April 1, 2013 and increased utilization of the Q4000 and Seawell, both of which were in drydock for a period of time during the second quarter of 2012. Our robotics revenues increased during the second quarter of 2013 reflecting the larger ROV fleet and higher ROVDrill revenues. Robotics revenues have been adversely affected by lower trenching activities period over period due to deferrals of many previously anticipated trenching projects in the North Sea region until later in 2013 or 2014. Revenues associated with our subsea construction vessels were also substantially lower in the second quarter of 2013 as compared to the same period in 2012 due to the Express performing work on a high revenue project off the coast of Israel in 2012 and the previously announced sale of the Caesar closing in mid-June 2013. The previously announced sale of the Express occurred on July 17, 2013 following the completion of the final project in its remaining backlog of work.

Our Production Facilities revenues increased by 21% for the three-month period ended June 30, 2013 as compared to the same period in 2012, which reflects a substantial increase in our total revenues

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under the new HP I contract for processing of production from the Phoenix field (see "Contracting Services Operations" above). The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements (see "Helix Fast Response System" above).

Gross Profit. Our Contracting Services gross profit increased by 106% for the three-month period ended June 30, 2013 as compared to the same period in 2012. This increase reflects an increase in our revenues primarily attributable to the increased number of our Contracting Services assets, including four additional ROVs and one additional well intervention vessel, and 93% utilization for the well intervention vessels during the second quarter of 2013 as compared to 67% utilization in same period last year. In addition, our prior year gross profit was adversely affected by $21.5 million of impairment charges, including $14.6 million related to the Intrepid, our former pipelay vessel that was sold in August 2012

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $2.4 million for the three-month period ended June 30, 2013 as compared to the same period in 2012. The decrease reflects the reduction in the size of our organization following the sale of ERT in February 2013, the winding up of our subsea construction operations, and the related effect of these transactions on the level of our corporate staffing.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $5.1 million for the three-month period ended June 30, 2013 as compared to the same period in 2012. The decrease was primarily due to the $3.7 million of proceeds recovered during the second quarter of 2012 following the exit of our participation in an Australian joint venture (Note 6). The decrease also reflects lower throughput at both the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $11.3 million for the three-month period ended June 30, 2013 as compared to $11.6 million for the same period in 2012. The decrease primarily reflects increases in capitalized interest and interest income. Capitalized interest totaled $2.3 million for the second quarter of 2013 as compared to $1.0 million for the second quarter of 2012. Generally, our capitalized interest will be increasing as the construction of the Q5000 and the upgrades to and modifications of the Helix 534 progress. Interest income totaled $0.3 million for the second quarter of 2013 as compared to $0.1 million for the same period in 2012. Despite a substantial reduction in our outstanding indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT, our interest expense for the second quarter of 2013 is $1.3 million higher than the $12.7 million reported for the same prior year period because we no longer allocate interest expense to ERT following the sale of ERT in February 2013 (Notes 4 and 7).

Loss on Early Extinguishment of Long-term Debt. The $0.6 million loss in the second quarter of 2013 was associated with the acceleration of the remaining deferred financing fees related to the term loan component of our former credit agreement following the repayments of indebtedness and the related termination of the credit agreement (Note 7).

Other Expense, Net. We reported net other expenses of $0.6 million for the three-month period ended June 30, 2013 as compared $1.7 million for the same period in 2012. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. We recorded foreign exchange losses of approximately $0.6 million in the second quarter of 2013 as compared to $1.7 million in the second quarter of 2012. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange losses were $0.1 million of gains and $0.1 million of losses related to our foreign exchange forward contracts in the second quarters of 2013 and 2012, respectively (Note 16).

Other Income – Oil and Gas. The $1.3 million income for the three-month period ended June 30, 2013 primarily represents the proceeds associated with our overriding royalty interests in ERT's Wang well following its initial production in late April 2013.

Income Tax Provision. Income taxes reflected an expense of $8.6 million in the second quarter of 2013 as compared to a benefit of $4.0 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 23.4% for the second quarter of 2013 was less favorable than the tax benefit that was recorded for the second quarter of 2012 as a result of projected year over year increases in profitability in the United States.

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Comparison of Six Months Ended June 30, 2013 and 2012

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$423,410	$454,101	$(30,691)
Production Facilities	44,567	39,985	4,582
Intercompany elimination	(38,370)	(66,783)	28,413
	$429,607	$427,303	$2,304
Gross profit (in thousands) —			
Contracting Services	$99,570	$92,850	$6,720
Production Facilities	26,133	20,207	5,926
Corporate and other	(3,080)	(9,214)	6,134
Intercompany elimination	(2,559)	(2,922)	363
	$120,064	$100,921	$19,143
Gross Margin —			
Contracting Services	24%	20%	
Production Facilities	59%	51%	
Total company	28%	24%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Construction vessels	5/86%	9/89%	
Well intervention	4/96%	3/76%	
ROVs	55/58%	51/67%	

(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 each category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues are as follows (in thousands):

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Increase/ (Decrease)
Contracting Services	$33,697	$43,739	$(10,042)
Production Facilities	4,673	23,044	(18,371)
	$38,370	$66,783	$(28,413)

Intercompany segment profit is as follows (in thousands):

	Six Months Ended June 30, 2013	2012	Increase/ (Decrease)
Contracting Services	$2,647	$3,009	$(362)
Production Facilities	(88)	(87)	(1)
	$2,559	$2,922	$(363)

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In the following disclosures regarding our results of operations, please refer to the tables above and Note 12 for supplemental information regarding our business segment results. Our disclosures specifically refer to our Contracting Services and Production Facilities segments. Disclosures regarding our former Oil and Gas segment are presented under “Discontinued Operations — Oil and Gas” below and in Note 4.

Revenues. Our Contracting Services revenues decreased by 7% for the six-month period ended June 30, 2013 as compared to the same period in 2012. The increase in revenues during the second quarter of 2013 (see “Comparison Three Months Ended June 30, 2013 and 2012” above) was more than offset by the reduction of revenues in the first quarter of 2013. The decrease during the comparable first quarter periods of 2013 and 2012 reflected significantly lower revenues associated with our subsea construction vessels, which were adversely affected by permitting delays related to the two remaining projects to be serviced by the Express prior to its planned sale and significant reductions in the utilization for our robotics vessels and ROVs. Typically the first quarter is affected by seasonal weather patterns in the North Sea and thus robotics activities generally decrease in the winter months. However, over the past few years we benefitted from robotics activities in the first quarter, including a number of North Sea trenching projects in early 2012. These decreases were partially offset by full utilization of our three well intervention vessels during the first quarter of 2013 as compared to 84% utilization in the first quarter of 2012. In 2012, the Q4000 underwent required regulatory dry dock, which resulted in the vessel being out of service for 28 days during the first quarter of 2012.

Our Production Facilities revenues increased by 11% for the six-month period ended June 30, 2013 as compared to the same period in 2012, which reflects a substantial increase in our total revenues under the new HP I contract for processing of production from the Phoenix field. The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements.

Gross Profit. Our Contracting Services gross profit increased by 7% for the six-month period ended June 30, 2013 as compared to the same period in 2012. Despite lower gross profit during the first quarter of 2013 due to both our robotics and subsea construction vessels performing lower margin work to reduce vessel idle time, our year-to-date 2013 gross profit benefitted from the increased number of our Contracting Services assets, including four additional ROVs and one additional well intervention vessel, and higher utilization of our well intervention vessels as compared to the same period last year. Our gross profit for the 2012 period was also negatively affected by $21.5 million of impairment charges, including $14.6 million related to the Intrepid, our former pipelay vessel that was sold in August 2012.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 16). The $14.1 million loss on commodity derivative contracts reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to cash settle our remaining open commodity derivative contracts.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $1.6 million for the six-month period ended June 30, 2013 as compared to the same period in 2012. The decrease reflects the reduction in the size of our organization following the sale of ERT in February 2013, the winding up of our subsea construction operations, and the related effect of these transactions on the level of our corporate staffing. This decrease in our selling, general and administrative expenses was partially offset by severance related costs of approximately $1.7 million in the first half of 2013.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $4.9 million for the six-month period ended June 30, 2013 as compared to the same period in 2012. The decrease primarily reflects the expiration in March 2012 of the supplemental demand fee to the major customers using Independence Hub. The decrease also reflects lower throughput at the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $21.7 million for the six-month period ended June 30, 2013 as compared to $26.1 million for the same period in 2012. The decrease reflects increases in capitalized interest and interest income and a reduction in interest expense. Capitalized interest totaled $4.3 million for the first half of 2013 as compared to $1.5 million for the first half of 2012. Generally, our capitalized interest will be increasing as the construction of the Q5000 and the upgrades to and modifications of the Helix 534 progress. Interest income totaled $0.6 million for the first half of 2013 as compared to $0.3 million for the same period in 2012. The decrease in interest expense reflects the substantial reduction in our outstanding indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT and the early redemption of $200 million of the Senior Unsecured Notes in March 2012. Prior to the final redemption of the Senior Unsecured Notes in July 2013, these notes bore a 9.5% interest rate which is greater than the 7.1% weighted average interest rate of our total indebtedness as of June 30, 2013. In addition, we no longer allocate interest expense to ERT following the sale of ERT in February 2013 (Notes 4 and 7).

Loss on Early Extinguishment of Long-term Debt. The $3.5 million loss in the first half of 2013 was associated with the acceleration of the remaining deferred financing fees related to the term loan component of our former credit agreement following the repayments of indebtedness and the related termination of the credit agreement (Note 7). The $17.1 million of charges in the first half of 2012 were associated with the early extinguishment of portions of our debt, including $11.5 million related to our repurchase of $200.0 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of the 2025 Notes.

Other Expense, Net. We reported net other expenses of $4.3 million for the six-month period ended June 30, 2013 as compared to $1.6 million for the same period in 2012. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. We recorded foreign exchange losses of approximately $4.3 million in the first half of 2013 as compared to $1.6 million in the first half of 2012. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $1.2 million of losses and $0.2 million of gains related to our foreign exchange forward contracts in the first halves of 2013 and 2012, respectively (Note 16).

Other Income – Oil and Gas. The $4.1 million income for the six-month period ended June 30, 2013 represents cash payments related to services we provided to ERT following its sale to a third party and the initial proceeds associated with our overriding royalty interests in ERT’s Wang well, which commenced production in late-April 2013.

Income Tax Provision. Income taxes reflected an expense of $9.0 million in the first half of 2013 as compared to a benefit of $2.7 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 23.5% for the first half of 2013 was less favorable than the tax benefit that was recorded for the first half of 2012 as a result of projected year over year increases in profitability in the United States.

Discontinued Operations — Oil and Gas

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. See our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2013 for operating results of our discontinued oil and gas operations during 2013. Our operating results for the three- and six-month periods ended June 30, 2012 are presented in Note 4. Our continuing operations included one property located offshore of the United Kingdom (“U.K.”). During the first quarter of 2013, we recorded a $1.6 million charge reflecting the estimated final costs to complete our U.K. property’s abandonment activities. We have completed the reclamation activities for this offshore property, including removing and appropriately disposing of all the related structures, and the plugging and abandoning of all the wells associated with the property. Our operating results for oil and gas operations were immaterial for the three-month period ended June 30, 2013.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	June 30, 2013	December 31, 2012
Net working capital	$ 576,946	$ 351,061
Long-term debt (1)	$ 543,341	$ 1,002,621
Liquidity (2)	$ 1,092,885	$ 924,688

(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 the 2032 Notes. We repaid $318.4 million of our outstanding indebtedness in February 2013 following the sale of ERT (see table below). See Note 7 for disclosures related to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by current letters of credit drawn against the facility. The increase in our liquidity reflects proceeds from the sales of ERT and the Caesar. Over the remainder of 2013, we anticipate a reduction in liquidity as a result of capital expenditures to expand our well intervention fleet and to fund other capital expenditures (see "Outlook" below). As of June 30, 2013, our liquidity included cash and cash equivalents of $513.5 million and $579.4 million of available borrowing capacity under our Revolving Credit Facility (Note 7). As of December 31, 2012, our liquidity included cash and cash equivalents of $437.1 million and $487.6 million of available borrowing capacity under our former revolving credit facility.

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

	June 30, 2013	December 31, 2012
Term Loans (mature July 2015) (1)	$ —	$ 367,181
Revolving Credit Facility (matures July 2015) (1)	—	100,000
2025 Notes (mature December 2025) (2)	—	3,487
2032 Notes (mature March 2032) (3)	170,869	168,312
Senior Unsecured Notes (mature January 2016) (4)	274,960	274,960
MARAD Debt (matures February 2027)	102,759	105,288
Total debt	$ 548,588	$ 1,019,228

(1) In February 2013, we repaid $293.9 million of our former term loan debt and $24.5 million under our former revolving credit facility with the after-tax proceeds from the sale of ERT. In June 2013, we used $80.1 million of the after-tax proceeds from the sale of the Caesar to as well as cash generated from operations to repay the remaining outstanding amounts under our former credit agreement (Note 7).

(2) This amount represents the remainder of the 2025 Notes we repurchased in February 2013 (Note 7).

(3)

These amounts are net of the unamortized debt discount of $29.1 million and $31.7 million, respectively. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the date on which the holders of the notes may first require us to repurchase the notes.

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(4) In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013, and we redeemed these notes in full on that date.

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

	Six Months Ended June 30,	
	2013	2012
Cash provided by (used in):		
Operating activities	$ 2,010	$ 118,817
Investing activities	$ 10,434	$ (113,734)
Financing activities	$ (491,527)	$ 27,116
Discontinued operations (1)	$ 552,462	$ 70,535

(1) Represents total cash flows associated with the operations of ERT. ERT was sold in February 2013. Proceeds from the sale of ERT totaled $614.8 million, net of related transaction costs. Other cash flows in the table above reflect our continuing operations.

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 may also repay debt with any additional free cash flow from operations and proceeds from the expected sale of our spoolbase in Ingleside, Texas. Historically, we have funded our capital program, including acquisitions, with cash flows 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 flows supported by our existing and expanding backlog. We believe that internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months.

In accordance with our Credit Agreement, 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. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by the Company or any of the Restricted Subsidiaries. As of June 30, 2013 and December 31, 2012, we were in compliance with all of our then existing 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.

Under the terms of our Credit Agreement, we borrowed $300 million under a term loan in July 2013 in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding. We may also borrow up to $600 million under the revolving credit facility. The revolving credit facility also permits us to obtain letters of credit up to the full amount of the credit facility. Subject to customary conditions, we may request aggregate commitments with respect to the revolving credit facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 7 for additional information related to our long-term debt, including more information regarding our current and former credit agreements and our requirements and obligations under the debt agreements including our covenants and collateral security.

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The 2032 Notes can be converted prior to their stated maturity under certain triggering events specified in the respective indentures governing each series of notes. Beginning on March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase notes. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our condensed consolidated balance sheet. No conversion triggers were met during the three- and six-month periods ended June 30, 2013 and 2012. The remainder of the 2025 Notes was extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us by the holders in December 2012.

Working Capital

Total cash flows from operating activities decreased by $249.5 million in the six-month period ended June 30, 2013 as compared to the same period in 2012. This decrease primarily reflects the sale of ERT on February 6, 2013, the related settlement of our commodity derivative and interest rate swap contracts, payment of income taxes, and lower utilization of our robotics and subsea construction vessels and related equipment.

Investing Activities

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

	Six Months Ended June 30,	
	2013	2012
Capital expenditures:		
Contracting Services	$(101,919)	$(115,006)
Production Facilities	(464)	(773)
Distributions from equity investments, net (1)	4,567	2,045
Proceeds from sale of assets	108,250	—
Net cash provided by (used in) investing activities – continuing operations	10,434	(113,734)
Oil and Gas capital expenditures	(31,855)	(34,328)
Proceeds from sale of ERT, net of related transaction costs	614,820	—
Other	—	2,660
Net cash provided by (used in) investing activities – discontinued operations	582,965	(31,668)
Net cash provided by (used in) investing activities	$593,399	$(145,402)

(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.

Capital expenditures associated with our contracting services business primarily include our Q5000 construction related payments (see below), payments in connection with the acquisition and subsequent upgrades to and modifications of the Helix 534 (see below), and costs incurred in the construction of additional ROVs and trenchers related to our robotics operations.

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In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At June 30, 2013, our total investment in the Q5000 was $146.0 million, including $115.9 million of scheduled payments made to the shipyard. We plan to spend approximately $132 million on the Q5000 during the remainder of 2013, including scheduled shipyard payments of $115.9 million. The vessel is expected to be completed and placed in service in 2015.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing upgrades and modifications to render it suitable for use as a well intervention vessel. At June 30, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $164.6 million, including related well control equipment. We estimate that an additional $29 million will be invested before the vessel is ready to be placed in service. The vessel is expected to join our well intervention fleet in the Gulf of Mexico in the fourth quarter of 2013.

Net cash used in discontinued operations relates to capital expenditures associated with ERT. Oil and Gas capital expenditures for the first quarter of 2013 included costs associated with the exploration and development activities primarily related to the Wang well within the Phoenix field at Green Canyon Block 237.

Outlook

We anticipate that our capital expenditures in 2013 will total approximately $365 million. These estimates may increase or decrease based on various economic factors and/or the existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that our cash on hand, internally-generated cash flows, and availability under our new credit facility will provide the capital necessary to continue funding our 2013 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of June 30, 2013 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2032 Notes (2)	$200,000	$—	$—	$—	$200,000
Senior Unsecured Notes (3)	274,960	—	274,960	—	—
MARAD debt	102,759	5,247	11,291	12,447	73,774
Interest related to debt (4)	218,946	25,252	45,587	40,747	107,360
Property and equipment (5)	314,552	156,734	157,818	—	—
Operating leases (6)	631,251	114,444	270,276	156,904	89,627
Total cash obligations	$1,742,468	$301,677	$759,932	$210,098	$470,761

(1) Excludes unsecured letters of credit outstanding at June 30, 2013 totaling $20.6 million. These letters of credit guarantee items such as various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing 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 130% of its issuance price on that 30th trading day (i.e., $32.53 per share). At June 30, 2013, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 7 for additional information regarding these 2032 Notes.

(3) In June 2013, we elected to redeem the remaining Senior Unsecured Notes on July 22, 2013, and we redeemed these notes in full on that date.

(4) Includes interest related the $300 million Term Loan we borrowed in July 2013 in connection with the redemption of the remaining Senior Unsecured Notes.

(5) Primarily reflects the costs related to construction of our new semi-submersible well intervention vessel, the Q5000, and costs associated with the upgrades and modifications to render the Helix 534 suitable for use as a well intervention vessel.

(6) Operating leases included facility leases and vessel charter leases. At June 30, 2013, our vessel charter and ROV lease commitments totaled approximately $591.9 million.

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 2012 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Interest Rate Risk. As of June 30, 2013, we had no debt outstanding that was subject to floating rates. However, the interest rate applicable to variable rate debt that we may incur from time to time may rise, increasing our interest expense and related cash outlay.

Foreign Currency Exchange Rate Risk. Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to our U.K. and Australian operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in i) currencies other than the U.S. dollar, which is our functional currency, or ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risks in areas outside the United States, we generally pay a portion of our expenses in local currencies and a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the six-month period ended June 30, 2013, we recognized losses of $3.1 million related to foreign currency transactions in “Other expense, net” in the condensed consolidated statement of operations.

We also entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds and Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million), through September 2017. In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. The loss resulting from changes in the fair value of our foreign exchange contracts that were not designated for hedge accounting totaled $0.6 million for the six-month period ended June 30, 2013.

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Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, 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 June 30, 2013. 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 June 30, 2013 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, 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 June 30, 2013.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 13 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum number of shares that may yet be purchased under the program (2)
April 1 to April 30, 2013	—	$ —	178,658	—
May 1 to May 31, 2013	9,294	24.44	—	—
June 1 to June 30, 2013	5,915	22.33	—	—
	15,209	$ 23.62	178,658	

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

(2) In April 2013, we repurchased 178,658 shares in open market transactions totaling $4.1 million for an average price of $22.85 per share under our stock repurchase program. For additional information regarding our stock repurchase program, see Note 11 of the 2012 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 52 hereof.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.
(Registrant)

Date: July 24, 2013 By: /s/ Owen Kratz
Owen Kratz
President and Chief Executive Officer
(Principal Executive Officer)

Date: July 24, 2013 By: /s/ Anthony Tripodo
Anthony Tripodo
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

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INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Credit Agreement dated June 19, 2013 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, and other lender parties named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on June 19, 2013 (001-32936)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith