HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 26, 2011

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 September 30, 2011

or

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

Commission File Number 001-32936

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

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

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

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

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

Yes [√] No [ ]

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

Yes [√] No [ ]

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

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

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

As of October 21, 2011, 105,473,384 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)

	September 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 375,355	$ 391,085
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $4,130 and $4,527, respectively	221,162	177,293
Unbilled revenue	13,878	33,712
Costs in excess of billing	14,996	15,699
Other current assets	123,236	123,065
Total current assets	748,627	740,854
Property and equipment	4,434,796	4,486,077
Less — accumulated depreciation	(1,961,043)	(1,958,997)
	2,473,753	2,527,080
Other assets:		
Equity investments	186,423	187,031
Goodwill	62,344	62,494
Other assets, net	80,862	74,561
Total assets	$ 3,552,009	$ 3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 145,112	$ 159,381
Accrued liabilities	159,676	198,237
Income taxes payable	3,856	—
Current maturities of long-term debt	7,877	10,179
Total current liabilities	316,521	367,797
Long-term debt	1,163,914	1,347,753
Deferred income taxes	441,520	413,639
Asset retirement obligations	169,429	170,410
Other long-term liabilities	4,844	5,777
Total liabilities	2,096,228	2,305,376
Convertible preferred stock	1,000	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,965 and 105,592 shares issued, respectively	913,976	906,957

Retained earnings	505,892	392,705
Accumulated other comprehensive income (loss)	7,520	(39,058)
Total controlling interest shareholders’ equity	1,427,388	1,260,604
Noncontrolling interests	27,393	25,040
Total equity	1,454,781	1,285,644
Total liabilities and shareholders’ equity	$ 3,552,009	$ 3,592,020

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 September 30, 2011	Three Months Ended September 30, 2010
Net revenues:		
Contracting services	$ 213,278	$ 297,103
Oil and gas	159,218	95,566
	372,496	392,669
Cost of sales:		
Contracting services	147,614	211,634
Oil and gas	100,230	93,586
Oil and gas property impairments	2,357	897
	250,201	306,117
Gross profit (loss)	122,295	86,552
Gain on oil and gas derivative contracts	—	161
Gain on the sale or acquisition of assets, net	—	13
Selling, general and administrative expenses	(22,082)	(26,628)
Income from operations	100,213	60,098
Equity in earnings of investments	4,906	6,221
Net interest expense	(24,114)	(25,479)
Other income (expense)	(10,714)	4,072
Income before income taxes	70,291	44,912
Provision for income taxes	23,465	17,965
Net income, including noncontrolling interests	46,826	26,947
Less net income applicable to noncontrolling interests….	(800)	(776)
Net income applicable to Helix	46,026	26,171
Preferred stock dividends	(10)	(10)
Net income applicable to Helix common shareholders	$ 46,016	$ 26,161
Earnings per share of common stock:		
Basic	$ 0.43	$ 0.25
Diluted	$ 0.43	$ 0.25
Weighted average common shares outstanding:		
Basic	104,700	104,090
Diluted	105,154	105,307

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)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net revenues:		
Contracting services	$ 501,887	$ 604,634
Oil and gas	500,535	288,867
	1,002,422	893,501
Cost of sales:		
Contracting services	371,042	438,008
Oil and gas	306,733	266,032
Oil and gas property impairments	25,078	171,871
	702,853	875,911
Gross profit	299,569	17,590
Gain on oil and gas derivative contracts	—	2,643
Gain (loss) on sale or acquisition of assets, net	(6)	6,246
Selling, general and administrative expenses	(70,821)	(91,675)
Income (loss) from operations	228,742	(65,196)
Equity in earnings of investments	16,443	12,932
Gain on sale of Cal Dive common stock	753	—
Net interest expense	(73,628)	(61,637)
Other income (expense)	(7,554)	(3,189)
Income (loss) before income taxes	164,756	(117,090)
Provision (benefit) for income taxes	49,186	(41,962)
Net income (loss), including noncontrolling interests	115,570	(75,128)
Less net income applicable to noncontrolling interests…	(2,354)	(2,049)
Net income (loss) applicable to Helix	113,216	(77,177)
Preferred stock dividends	(30)	(104)
Net income (loss) applicable to Helix common shareholders	$ 113,186	$ (77,281)
Earnings (loss) per share of common stock:		
Basic	$ 1.07	$ (0.74)
Diluted	$ 1.06	$ (0.74)
Weighted average common shares outstanding:		
Basic	104,616	103,772

Diluted	105,061	103,772

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)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cash flows from operating activities:		
Net income (loss), including noncontrolling interests	$ 115,570	$ (75,128)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	239,540	222,730
Asset impairment charge and dry hole expense	32,736	171,626
Amortization of deferred financing costs	7,197	5,731
Stock compensation expense	6,835	6,889
Amortization of debt discount	6,693	6,272
Deferred income taxes	31,707	(53,335)
Excess tax benefit from stock-based compensation	805	2,376
Gain on investment in Cal Dive common stock	(753)	—
Loss on early extinguishment of Senior Unsecured Notes	2,354	—
(Gain) loss on sale or acquisition of assets	6	(6,246)
Unrealized (gain) loss on derivative contracts	433	2,304
Changes in operating assets and liabilities:		
Accounts receivable, net	(24,205)	(29,256)
Other current assets	(11,100)	3,947
Income tax payable	9,129	4,896
Accounts payable and accrued liabilities	(28,668)	38,662
Oil and gas asset retirement costs	(34,836)	(52,244)
Other noncurrent, net	(2,312)	(7,458)
Net cash provided by operating activities	351,131	241,766
Cash flows from investing activities:		
Capital expenditures	(167,849)	(179,018)
Investments in equity investments	(2,699)	(7,768)
Distributions from equity investments, net	3,437	9,876
Proceeds from sale of Cal Dive common stock	3,588	—
Insurance recovery for capital items	—	16,106
Proceeds from sales of property	—	852

Decrease (increase) in restricted cash	703	(133)
Net cash used in investing activities	(162,820)	(160,085)
Cash flows from financing activities:		
Borrowing under revolving credit facility	109,400	—
Repayment of revolving credit facility	(109,400)	—
Repayment of Helix Term Loan	(111,941)	(3,245)
Early extinguishment of Senior Unsecured Notes	(77,394)	—
Repayment of MARAD borrowings	(4,645)	(4,866)
Loan notes repayment	(1,215)	(1,842)
Deferred financing costs	(9,224)	(2,864)
Repurchases of common stock and preferred dividends paid	(1,102)	(11,763)
Excess tax benefit from stock-based compensation	(805)	(2,376)
Exercise of stock options, net	2,018	335
Net cash used in financing activities	(204,308)	(26,621)
Effect of exchange rate changes on cash and cash equivalents	267	(253)
Net (decrease) increase in cash and cash equivalents	(15,730)	54,807
Cash and cash equivalents:		
Balance, beginning of year	391,085	270,673
Balance, end of period	$ 375,355	$ 325,480

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

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

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and are consistent in all material respects with those applied in our 2010 Annual Report on Form 10-K (“2010 Form 10-K”). The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations, and cash flows, as applicable. The operating results for the periods ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. Our balance sheet as of December 31, 2010 included herein has been derived from the audited balance sheet as of December 31, 2010 included in our 2010 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 2010 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, including reclassifying the previously recorded results associated with our discontinued operations. The discontinued operations results are now reflected as a component of other income (expense) in the accompanying condensed consolidated statement of operations as such amounts are immaterial for all the periods presented in this Quarterly Report on Form 10-Q.

Note 2 – Company Overview

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

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: subsea construction, well operations, robotics and production facilities. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting

Services business primarily includes subsea construction, deepwater pipelay, well operations and robotics activities. Our Production Facilities business includes our equity investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") as well as our majority ownership of the Helix Producer I ("HP I") vessel. We have developed a response system that has been referenced as a designated spill response resource in Gulf of Mexico permit applications (see "Events in Gulf of Mexico" below), which is also a component of our Production Facilities segment.

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Oil and Gas Operations

We began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand off-season utilization of our contracting services assets and to achieve incremental returns. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be explored and developed. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Events in Gulf of Mexico

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252. The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S. territorial waters. In May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. In October 2010, the DOI lifted the drilling moratorium and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. No post moratorium deepwater drilling permits were issued by BOEMRE until late February 2011.

We developed the Helix Fast Response System ("HFRS") as a culmination of our experience as a responder in the Gulf oil spill response and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Gulf oil spill response and containment efforts and are presently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS be deployed in connection with a well control incident. The retainer fee for the HFRS became effective April 1, 2011 and is a component of our Production Facilities business segment. A total of 38 permits have been granted to CGA participants for deepwater drilling operations identifying the HFRS to fulfill the BOERME requirement to have a spill response and containment resource included in the submitted permit applications.

New Accounting Pronouncement

In June 2011, the Financial Accounting Standards Board ("FASB") issued an update to existing guidance on the presentation of comprehensive income. This update will require the presentation of the components of net income and other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In addition, companies are also required to present reclassification adjustments for items that are reclassified from other comprehensive income to net income on the face of the financial statements. The update is effective for fiscal years and interim periods beginning after December 15, 2011. We will adopt the new disclosure requirements for comprehensive income beginning January 1, 2012 and are currently evaluating the provisions of this update.

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Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in thousands)	
Other receivables	$ 2,767	$ 1,247
Prepaid insurance	20,539	12,375
Other prepaids	14,032	11,623
Spare parts inventory	21,602	25,333
Current deferred tax assets	21,758	49,200
Hedging assets	33,203	5,472
Gas imbalance	4,817	6,001
Income tax receivable	—	6,099
Investment held for sale (a)	—	2,835
Other	4,518	2,880
	$ 123,236	$ 123,065

a. In March 2011, we sold our remaining 500,000 shares of common stock in our former subsidiary Cal Dive International, Inc. ("Cal Dive"). These sales transactions resulted in net proceeds of approximately $3.6 million and a pre-tax gain of $0.8 million. In the fourth quarter of 2010, we recognized a $2.2 million other than temporary loss on our investment in Cal Dive common shares (see Notes 2 and 3 of our 2010 Form 10-K for additional information regarding our former Investment in Cal Dive common stock).

Other assets, net, consisted of the following as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in thousands)	
Restricted cash	$ 34,636	$ 35,339
Deferred drydock expenses, net	6,576	11,086
Deferred financing costs, net	28,013	25,697
Intangible assets with finite lives, net	559	636
Hedging assets	9,428	—
Other	1,650	1,803
	$ 80,862	$ 74,561

Accrued liabilities consisted of the following as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in thousands)	
Accrued payroll and related benefits	$ 41,261	$ 38,026
Royalties payable	15,140	15,008
Current asset retirement obligations	63,816	64,526
Unearned revenue	7,900	4,094

Billing in excess of cost	5,297	3,869
Accrued interest	13,795	27,308
Hedge liability	956	30,606
Other	11,511	14,800
	$ 159,676	$ 198,237

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Note 4 – Oil and Gas Properties

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

Depletion expense is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated total remaining proved reserves. Depletion rates for well and related facility costs are based on estimated total remaining proved developed reserves associated with each individual field. The depletion rates are changed whenever there is an indication of the need for a revision, but at a minimum, are evaluated annually. Any such revisions are accounted for prospectively as a change in accounting estimate.

Impairments

During the third quarter of 2011, we recorded a total of $2.4 million of impairment charges primarily related to revisions in cost estimates for reclamation activities ongoing at two of our Gulf of Mexico oil and gas properties. For the three-month period ended June 30, 2011, we recorded impairment charges totaling $22.7 million, including $4.1 million for our only non-domestic oil and gas property (see "United Kingdom Property" below), and for six of our Gulf of Mexico oil and gas properties. These impairment charges primarily reflect a premature end of these fields' production life either through actual depletion or as a result of capital allocation decisions affecting our third party operated fields. We did not have any impairment of our oil and gas properties during the three-month period ended March 31, 2011.

Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. In the first quarter of 2010, we recorded $7.0 million of impairment charges primarily resulting from natural gas price declines since year end 2009. The three properties subject to these impairment charges produce natural gas almost entirely. Separately, we also recorded a $4.1 million impairment charge for our United Kingdom oil and gas property.

Exploration and Other

As of September 30, 2011, we capitalized approximately $4.6 million of costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

The following table details the components of exploration expense for the three- and nine-month periods ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Delay rental and geological and geophysical costs	$ 522	$ 497	$ 2,176	$ 2,025
Impairment of unproved properties	1,028	—	7,668a	—

Dry hole expense and other	(2)	(55)	(11)	(245)
Total exploration expense	$ 1,548	$ 442	$ 9,833	$ 1,780

a. Includes the costs ($6.6 million) associated with a deepwater lease the term of which expired during the second quarter of 2011.

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United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. In 2007, we sold half of our 100% working interest in Camelot to a third party with whom we agreed to jointly pursue future development and production of the field. In February 2010, we acquired this third party and thereby assumed the obligations, most notably the asset retirement obligation, related to its 50% working interest in the field. We recorded an approximate $6.0 million gain on the acquisition of the remaining working interest in Camelot, including the acquired entity's $10.2 million of cash (see Note 5 of 2010 Form 10-K).

In connection with this acquisition, we reassessed the fair value associated with our original 50% interest in the field. Based on these evaluations, we concluded that the Camelot field was impaired based on the unlikely probability of our expending the additional capital necessary to further develop the field. As a result, we recorded a $4.1 million impairment charge to fully impair the property in the first quarter of 2010. We are currently abandoning the field in accordance with applicable United Kingdom regulations. In connection with these activities, we continue to evaluate our estimated future field abandonment costs for the field. These evaluations resulted in our recording an incremental $4.1 million impairment charge in the second quarter of 2011 to increase the field's estimated reclamation liability. Our current estimated asset retirement obligation for the Camelot field totals $11.6 million at September 30, 2011. We have incurred approximately $4.8 million of costs related to our reclamation activities at the Camelot field through September 30, 2011.

Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2010 (in thousands):

Asset retirement obligations at December 31, 2010	$ 234,936
Liability incurred during the period	1,372
Liability settled during the period	(36,591)
Revision in estimated cash flows	22,276
Accretion expense (included in depreciation and amortization)	11,252
Asset retirement obligations at September 30, 2011	$ 233,245

Insurance

We carry comprehensive insurance for our operated and non-operated producing and non-producing properties. We record our hurricane-related costs as incurred. Insurance reimbursements are recorded when the realization of the claim for recovery of a loss is deemed probable. In 2011, our hurricane-related costs have been immaterial. Hurricane-related costs, net of reimbursements totaled $0.9 million and $4.6 million for the three-month and nine-month periods ended September 30, 2010. Our insurance reimbursements totaled $5.0 million for the nine-month period ended September 30, 2011. On June 30, 2011, we renewed our hurricane catastrophic bond for the period from July 1, 2011 to June 30, 2012 and made a payment of $10.6 million. We recorded a charge of approximately $8.4 million to insurance expense in the third quarter of 2011 to reduce the value of our hurricane catastrophic bond to its intrinsic value at September 30, 2011. We will record a $2.0 million charge to insurance expense in the fourth quarter of 2011.

Note 5 – Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. We had restricted cash totaling $34.6 million at September 30, 2011 and $35.3 million at December 31, 2010, all of which was related to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

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The following table provides supplemental cash flow information for the nine-month period ended September 30, 2011 and 2010 (in thousands):

	Nine Months Ended September 30,	
	2011	2010
Interest paid, net of capitalized interest	$ 73,096	$ 60,137
Income taxes paid	$ 9,575	$ 8,020

Non-cash investing activities for the nine-month periods ended September 30, 2011 and 2010 included $34.8 million and $17.5 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 6 – Equity Investments

As of September 30, 2011, we have three investments that we account for using the equity method of accounting: Deepwater Gateway, Independence Hub, and Clough Helix Joint Venture Pty Ltd. ("Clough Helix JV"). Deepwater Gateway and Independence Hub are included in our Production Facilities segment while the Clough Helix JV is a component of our Contracting Services 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 Gulf of Mexico. Our investment in Deepwater Gateway totaled $96.8 million at September 30, 2011 and $99.8 million at December 31, 2010 (including capitalized interest of $1.4 million at September 30, 2011 and $1.5 million December 31, 2010). Our equity in earnings of Deepwater Gateway totaled $0.6 million and $2.7 million for the respective three-month and nine-month periods ended September 30, 2011 as compared to $1.3 million and $3.6 million for the three-month and nine-month periods ended September 30, 2010, respectively. Distributions from Deepwater Gateway, net to our interest, totaled $2.2 million and $5.7 million for the respective three-month and nine-month periods ended September 30, 2011.

· Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. First production through the facility commenced in July 2007. Our investment in Independence Hub was $80.2 million at September 30, 2011 and $82.4 million at December 31, 2010 (including capitalized interest of $5.0 million at September 30, 2011 and $5.2 million at December 31, 2010). Our equity in earnings of Independence Hub totaled $4.0 million and $12.3 million for the respective three-month and nine-month periods ended September 30, 2011 as compared to $4.2 million and $14.1 million for the three-month and nine-month periods ended September 30, 2010, respectively. Distributions from Independence Hub, net to our interest, totaled $4.6 million and $14.2 million for the three-month and nine-month periods ended September 30, 2011, respectively.

· Clough Helix JV. In February 2010, we announced the formation of the Clough Helix JV with Australian-based engineering and construction company, Clough Projects Australia Pty Ltd ("Clough"), to provide a range of subsea services to offshore operators in the Asia Pacific region. The Clough Helix JV combines our well intervention equipment with Clough's 12-man saturation diving system, which are deployed from the 118 meter long DP2 multiservice vessel, Normand Clough. In the first quarter of 2011, the Clough Helix JV commenced an approximate six- to nine-month day rate project located offshore China. Our 50% share of the earnings from the Clough Helix JV totaled \$0.3 million and \$1.4 million for the three- and nine-month periods ended September 30, 2011, respectively as compared to \$0.7 million of earnings and \$5.0 million of losses in the three- and nine-month periods ended September 30, 2010, respectively. The loss in the nine-month 2010 period primarily represented the mobilization costs of transporting the Normand Clough from the Gulf of Mexico to Singapore and other start up costs. Our investment in the Clough Helix JV was \$9.4 million at September 30, 2011 and \$4.9 million at December 31, 2010.

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Note 7 – Long-Term Debt

Scheduled maturities of long-term debt outstanding as of September 30, 2011 were as follows (in thousands):

	Term Loan	Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes (1)	MARAD Debt	Total
Less than one year	$3,000	$	$	$	$4,877	$7,877
One to two years	3,000				5,120	8,120
Two to three years	3,000				5,376	8,376
Three to four years	289,500				5,644	295,144
Four to five years			474,960		5,925	480,885
Over five years				300,000	83,224	383,224
Total debt	298,500		474,960	300,000	110,166	1,183,626
Current maturities	(3,000)				(4,877)	(7,877)
Long-term debt, less current maturities	295,500		474,960	300,000	105,289	1,175,749
Unamortized debt discount (2)				(11,835)		(11,835)
Long-term debt	$295,500	$	$474,960	$288,165	$105,289	$1,163,914

(1) Beginning in December 2012, the holders may require us to repurchase the notes or we may at our own option elect to repurchase the notes. The notes will mature in March 2025.
(2) The notes will increase to the $300 million face amount through accretion of non-cash interest charges through 2012.

At September 30, 2011, unsecured letters of credit issued totaled approximately $42.6 million (see "Credit Agreement" below). These letters of credit primarily guarantee various contract bidding, contractual performance, including asset retirement obligations, and insurance activities. The following table details our interest expense and capitalized interest for the three- and nine-month periods ended September 30, 2011 and 2010:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in thousands)			
Interest expense	$ 25,175	$ 25,784	$ 75,971	$ 74,730
Interest income	(600)	(263)	(1,575)	(660)
Capitalized interest	(461)	(42)	(768)	(12,433)
Interest expense, net	$ 24,114	$ 25,479	$ 73,628	$ 61,637

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt see Note 9 of our 2010 Form 10-K.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors.

During the three-month period ended September 30, 2011, we purchased a portion of our Senior Unsecured Notes that resulted in the early extinguishment of an aggregate $75.0 million of those notes. In these transactions we paid an aggregate amount of $77.4 million, including the $75.0 million in principal and $2.4 million in premium for the repurchased Senior Unsecured Notes. The premium is reflected as a component of "other income (expense)" in the accompanying condensed consolidated statements of operations. We also paid the accrued interest on these Senior Unsecured Notes totaling

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$0.8 million and we recorded a $0.9 million charge to interest expense to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes in 2007.

Credit Agreement

In July 2006, we entered into a credit agreement (the "Credit Agreement") containing both a term loan (the "Term Loan") and a revolving credit facility (the "Revolving Credit Facility"). The $835 million term loan was used to fund the cash portion of the acquisition of Remington Oil and Gas Corporation in July 2006. The original borrowing capacity under the Revolving Credit Facility was $300 million. In June 2011, we amended our Credit Agreement as further discussed below. For additional information regarding the previous terms of our Credit Agreement see Note 9 of our 2010 Form 10-K.

The fourth amendment to our Credit Agreement, among other things:

- increases the Revolving Credit Facility to $600.0 million (capacity was $435 million prior to the closing of the fourth amendment);
- provided for the repayment of $109.4 million of the outstanding principal portion of the Term Loan together with accrued interest thereon and related costs;
- extends the maturity date of the Term Loan from July 1, 2013 to a maturity date that is the earlier of (A) July 1, 2016, or (B), if our currently outstanding Senior Unsecured Notes due in 2016 are not fully re-financed or repaid by July 1, 2015, July 1, 2015;
- extends the maturity date of the Revolving Credit Facility from November 30, 2012 to a maturity date that is the earlier of (A) January 1, 2016, or (B), if our currently outstanding Senior Unsecured Notes due in 2016 are not fully re-financed or repaid by July 1, 2015, July 1, 2015;
- relaxes limitations on our right to dispose of certain Contracting Services assets comprising collateral to the Credit Agreement;
- increases the amount of restricted payments in the form of stock repurchases or redemptions that we are permitted to repurchase or redeem up to $50 million;
- permits us to repurchase or redeem all or part of our Convertible Senior Notes or Senior Unsecured Notes assuming certain conditions are met pro forma for any such transaction, including maintaining minimum levels of liquidity (defined as cash on hand and availability under our Revolving Credit Facility) of (A) $400 million with respect to the Convertible Senior Notes, and (B) $500 million with respect to the Senior Unsecured Notes; and
- increases the maximum amount of all investments permitted in subsidiaries that are neither loan parties nor whose equity interests are pledged from $150 million to $200 million.

With the closing of the fourth amendment, the Term Loan currently bears interest either at the one-, two-, three- or six-month LIBOR or Base Rates at our election plus a margin of between 3.25% and 3.5% (LIBOR margin) or 2.25% to 2.5% (Base Rate margin) depending on current leverage ratios. Our average interest rate on the Term Loan for the nine-month periods ended September 30, 2011 and 2010 was approximately 3.6% and 2.9%, respectively, including the effects of our interest rate swaps (Note 16).

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we may enter into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan (Note 16).

The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At September 30, 2011, we had no amounts drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $557.4 million, net of $42.6 million of letters of credit issued.

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Pursuant to the fourth amendment, the borrowings outstanding under the Revolving Credit Facility will bear interest based on one-, two-, three- or six-month LIBOR rates or on Base Rates at our election plus an applicable margin. The LIBOR margin ranges from 2.5% to 3.5% and the Base Rate margin rates from 1.5% to 2.5%, depending on our consolidated leverage ratio. In connection with the closing of the fourth amendment to our Credit Agreement (as noted above), we borrowed $109.4 million under the Revolving Credit Facility and prepaid a portion of the Term Loan. We subsequently repaid all borrowings under our Revolving Credit Facility with our available cash on hand. There were no borrowings outstanding on the Revolving Credit Facility at any time during the third quarter of 2011.

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

Convertible Senior Notes

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

The Convertible Senior Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during either the three- or nine-month periods ended September 30, 2011 and September 30, 2010. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012 (see Note 9 of our 2010 Form 10-K). Effective January 1, 2009, we adopted certain accounting standards that required us to discount the principal amount of our Convertible Senior Notes. Following adoption of these accounting standards, the effective interest rate for the Convertible Senior Notes is 6.6%.

Our average share price was below the $32.14 per share conversion price for all the periods presented in this Quarterly Report on Form 10-Q. As a result of our share price being lower than the $32.14 per share conversion price for these periods there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is payable in cash, and such shares would be issued on conversion. The Convertible Senior Notes are convertible into a maximum of 13,303,770 shares of our common stock.

MARAD Debt

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

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Other

In accordance with our Credit Agreement and our Senior Unsecured Notes, Convertible Senior 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 September 30, 2011, we were in compliance with these covenants and restrictions.

Deferred financing costs of $28.0 million and $25.7 million are included in other assets, net as of September 30, 2011 and December 31, 2010, respectively, and are being amortized over the life of the applicable loan agreements. We incurred $9.2 million of deferred financing costs related to the fourth amendment to our Credit Agreement and charged $0.8 million of deferred financing costs to interest expense associated with the repayment of $109.4 million of our Term Loan balance in June 2011 (see "Credit Agreement" above). In the third quarter of 2011, we charged $0.9 million of deferred financing costs to interest expense associated with purchases and early extinguishment of a portion of our Senior Unsecured Notes (see "Senior Unsecured Notes" above).

Note 8 – Income Taxes

The effective tax rates for the three-month and nine-month periods ended September 30, 2011 were 33.4% and 29.9%, respectively. The effective tax rates for the three-month and nine-month periods ended September 30, 2010 reflected a provision of 40.0% and a benefit of 35.8%, respectively. The variance of the comparable year-over-year periods primarily reflect the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions. Our effective tax rate increased in the third quarter of 2011, primarily reflecting increased profitability in our U.S. operations and certain losses associated with our Australian operations that are nondeductible for income tax purposes.

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

Note 9 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three and nine-month periods ended September 30, 2011 and 2010 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income (loss), including noncontrolling interests	$ 46,826	$ 26,947	$ 115,570	$ (75,128)
Other comprehensive income (loss), net of tax				
Foreign currency translation gain (loss)	1,588	5,436	2,287	(8,372)
	33,888	(3,795)	44,291	12,308

Unrealized gain (loss) on hedges, net				
Unrealized loss on investment available for sale		(123)		(679)
Total other comprehensive income (loss)	$ 82,302	$ 28,465	$ 162,148	$ (71,871)

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

	September 30, 2011	December 31, 2010
Cumulative foreign currency translation adjustment	$ (19,975)	$ (22,262)
Unrealized gain (loss) on hedges, net	27,495	(16,796)
Accumulated other comprehensive income (loss)	$ 7,520	$ (39,058)

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Note 10 – Earnings Per Share

We have shares of restricted stock issued and outstanding, some of which remain subject to certain vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

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

	Three Months Ended September 30, 2011		Three Months Ended September 30, 2010	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$46,016		$26,161	
Less: Undistributed net income allocable to participating securities	(549)		(356)	
Net income applicable to common stock	$45,467	104,700	$25,805	104,090

	Three Months Ended September 30, 2011		Three Months Ended September 30, 2010	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share – Basic	$ 45,467	104,700	$ 25,805	104,090
Effect of dilutive securities:				
Stock options		93		22
Undistributed earnings reallocated to participating securities	2		5	
Convertible Senior Notes				
Convertible preferred stock	10	361		1,195
Net income per common share – Diluted	$ 45,479	105,154	$ 25,810	105,307

	Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
	Income	Shares	Income	Shares

Basic:							
Net income (loss) applicable to common shareholders	$	113,186			$	(77,281	)	
Less: Undistributed net income allocable to participating securities		(1,403	)					
Net income (loss) applicable to common stock	$	111, 783		104,616	$	(77,281	)	103,772

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	Nine Months Ended September 30, 2011			Nine Months Ended September 30, 2010		
	Income		Shares	Income		Shares
Diluted:						
Net income (loss) per common share – Basic	$	111,783	104,616	$	(77,281)	103,772
Effect of dilutive securities:						
Stock options			84			
Undistributed earnings reallocated to participating securities		6				
Convertible Senior Notes						
Convertible preferred stock		30	361			
Net income (loss) per common share – Diluted	$	111,819	105,061	$	(77,281)	103,772

We had a net loss from continuing operations for the nine-month period ended September 30, 2010. Accordingly, we had no dilutive securities during this reporting period as their inclusion would have had an anti-dilutive effect on our EPS calculation, meaning it would have increased our reported EPS amount. The following table provides the effect the excluded securities would have had on our diluted shares calculation for the nine-month period ended September 30, 2010 assuming we had earnings from continuing operations (in thousands):

Diluted shares (as reported)	103,772
Stock options	51
Convertible preferred stock	1,689
Total	105,512

Note 11 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the “1995 Incentive Plan”) and the 2005 Long-Term Incentive Plan, as amended (the “2005 Incentive Plan”). As of September 30, 2011, there were 985,070 shares available for grant under our 2005 Incentive Plan.

There were no stock option grants in the three- and nine-month periods ended September 30, 2011 and 2010. During the nine-month period ended September 30, 2011, we made the following restricted share grants to executive officers, selected management employees and non-employee members of the board of directors under the 2005 Incentive Plan:

Date of Grant	Shares	Market Value Per Share	Vesting Period
January 4, 2011	475,804	$12.14	20% per year over five years
January 4, 2011	4,427	12.14	100% on January 1, 2013
April 1, 2011	2,907	17.20	100% on January 1, 2013
May 11, 2011	21,608	16.14	20% per year over five years

July 1, 2011	2,095	16.56	100% on January 1, 2013

Compensation cost is recognized over the applicable vesting periods on a straight-line basis. For the three- and nine-month periods ended September 30, 2011, $1.9 million and $6.8 million, respectively, was recognized as compensation expense related to restricted shares as compared with $2.1 million and $6.7 million during the three- and nine-month periods ended September 30, 2010, respectively.

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In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long term cash-based compensation to eligible employees. Under the terms of the 2009 LTI Plan, the majority of the cash awards are fixed sum amounts payable annually over a five-year vesting period. Some of the cash awards, however, are indexed to the Company's common stock price and the payment amount at each vesting date will fluctuate based on the common stock's performance. As a result, the compensation expense associated with those awards is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as appropriate.

Total compensation expense under the 2009 LTI plan totaled \$0.4 million and \$5.0 million for the three- and nine-month periods ended September 30, 2011, respectively. For the three- and nine-month periods ended September 30, 2010, total compensation under the 2009 LTI plan totaled \$0.8 million and \$3.4 million, respectively. The liability balance under the 2009 LTI Plan was \$7.0 million at September 30, 2011 and \$7.9 million at December 31, 2010, including \$5.8 million at September 30, 2011 and \$6.2 million at December 31, 2010 associated with the variable portion of the 2009 LTI plan.

For more information regarding our stock-based compensation plans, including our 2009 LTI Plan see Note 12 of our 2010 Form 10-K.

Note 12 – Business Segment Information

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Revenues				
Contracting Services	$ 229,967	$ 238,531	$ 532,857	$ 595,048
Production Facilities	19,986	74,458	56,101	97,169
Oil and Gas	159,218	95,566	500,535	288,867
Intercompany elimination	(36,675)	(15,886)	(87,071)	(87,583)
Total	$ 372,496	$ 392,669	$ 1,002,422	$ 893,501
Income (loss) from operations				
Contracting Services	$ 47,363	$ 31,015	$ 81,194	$ 102,282
Production Facilities (1)	10,983	44,520	28,859	57,460
Oil and Gas	48,622	(4,384)	144,926	(159,991)
Corporate (2)	(6,227)	(10,767)	(25,780)	(46,242)

Intercompany elimination	(528)	(286)	(457)	(18,705)
Total	$ 100,213	$ 60,098	$ 228,742	$ (65,196)
Equity in earnings of equity investments (Note 6)	$ 4,906	$ 6,221	$ 16,443	$ 12,932

(1) In April 2009, Kommandor LLC commenced leasing the HP I to us under terms of a charter arrangement following the completion of the initial conversion of the vessel (Note 8 of our 2010 Form 10-K). The HP I was certified as a floating oil and gas production unit in June 2010 following the completion of installation of oil and gas processing facilities on the vessel.

(2) The nine-month period ended September 30, 2010, included $13.8 million of $17.5 million settlement of a third party claim against us in March 2010 (Note 14).

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Intercompany segment revenues during the three- and nine-month periods ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Contracting Services	$ 25,410	$ 15,886	$ 52,574	$ 84,053
Production Facilities	11,265		34,497	3,530
Total	$ 36,675	$ 15,886	$ 87,071	$ 87,583

Intercompany segment gross profit (losses) during the three- and nine-month periods ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Contracting Services	$ 606	$ 330	$ 645	$ 15,473
Production Facilities	(78)	(44)	(188)	3,249
Total	$ 528	$ 286	$ 457	$ 18,722

Our identifiable assets as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011	December 31, 2010
	(in thousands)	
Identifiable Assets		
Contracting Services	$1,871,004	$1,856,016
Production Facilities	513,586	512,990
Oil and Gas	1,167,419	1,223,014
Total	$3,552,009	$3,592,020

Note 13 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a deepwater Gulf of Mexico prospect, from a third party. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or “OKCD”), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix’s 20% working interest. Production began in December 2003. Our payments to OKCD totaled $2.3 million and $7.3 million for the three-month and nine-month periods ended September 30, 2011, respectively, and $2.7 million and $8.7 million in the three-month and nine-month periods ended September 30, 2010, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 80.7% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees, who are required to maintain their employment status with Helix in order to retain such income participations.

Note 14 – Commitments and Contingencies

Litigation and Claims

In the first quarter of 2010, our results included approximately $17.5 million in expenses associated with a settlement agreement related to an offshore construction contract dispute in Australia (see Note 16 of 2010 Form 10-K), including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. These amounts were recorded as selling, general and administrative expenses in the accompanying condensed consolidated statements of operations.

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Loss Contract

In 2010 our Australian subsidiary contracted for a project to plug, abandon and salvage subsea wells in an oil and gas field located offshore China (see Note 16 of the 2010 Form 10-K). As previously reported, as of the year ended December 31, 2010 we had recorded an aggregate pre-tax loss of approximately $30 million related to this project which reflected the difficulty we had in plugging the wells because of certain structural issues, start-up issues with our recently repaired subsea intervention device and significant weather related delays. In the first quarter of 2011, this project ended and we recorded an additional pre-tax loss of approximately $0.2 million. We collected our remaining $6.7 million trade receivable related to this project in the third quarter of 2011.

Contingencies and Claims

We were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivables and claims 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 number of factors associated with the ongoing negotiations with the prime contractor, in 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable (see Notes 16 and 18 of our 2010 Form 10-K). However, at the time of this filing no final commercial resolution of this matter has been reached.

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

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

Note 15 – Fair Value Measurements

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 in which there is little or no market data, which require the reporting entity to develop its own assumptions.

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

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at September 30, 2011 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	$–	$42,284	$–	$42,284	(c)
Foreign currency forwards	–	109	–	109	(c)
Interest rate swaps	–	238	–	238	(c)
Liabilities:					
Fair value of long term debt(2)	1,063,501	124,212	–	1,187,713	(a), (b)
Foreign currency forwards	–	264	–	264	(c)
Interest rate swaps	–	692	–	692	(c)
Total net liability	$1,063,501	$82,537	$–	$1,146,038	

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

(2) We have elected not to record our debt at fair value in the accompanying condensed consolidated balance sheets. See Note 7 for additional information regarding our long term debt. The fair value of our long term debt at September 30, 2011 is as follows:

	Fair Value	Carrying Value	
Term Loan (matures July 2015)	$ 289,545	$ 298,500	
Revolving Credit Facility (matures July 2015)			
Convertible Senior Notes (matures March 2025)	289,497	300,000	(a)
Senior Unsecured Notes (matures January 2016)	484,459	474,960	
MARAD Debt (matures February 2027) (b)	124,212	110,166	
Total	$ 1,187,713	$ 1,183,626	

(a)

Amount excludes the $11.8 million of unamortized discount remaining on the Convertible Senior Notes at September 30, 2011.

(b) The estimated fair value of all debt, other than 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 market place with similar terms. The fair value of the MARAD debt was estimated using Level 2 fair value inputs using the cost approach.

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We review long lived assets for impairment whenever events occur or changes in circumstances indicate that the carrying amount of assets may not be recoverable. In such evaluation, the estimated future undiscounted cash flows to be generated by the asset are compared with the carrying value of the asset to determine if impairment may be required. For our oil and gas properties, the estimated future undiscounted cash flows are based on estimated crude oil and natural gas proved and probable reserves and published future market commodity prices, estimated operating costs and estimates of future capital expenditures. If the estimated undiscounted cash flows for a particular asset are not sufficient to cover the carrying value of the asset, the asset is impaired and its carrying value is reduced to the current fair value. The fair value of these assets is determined using an income approach by calculating present value of future cash flows attributable to the asset based on market information (such as forward commodity prices), estimates of future costs and estimated proved and probable reserve quantities. These fair value measurements fall within Level 3 of the fair value hierarchy.

In the third quarter of 2011, we recorded $2.4 million of impairment charges for two Gulf of Mexico oil and gas properties that are in the process of being abandoned. In the second quarter of 2011, we recorded impairment charges on seven of our oil and gas properties. These impairment charges reduced these oil and gas properties to their estimated fair value, which, for six of the properties, including our only United Kingdom oil and gas property, was zero and for the remaining property was $2.9 million at June 30, 2011. At June 30, 2010 we impaired 15 of our Gulf of Mexico properties as a result of reductions in estimates of proved reserves. The total amounts of these impairment charges were $159.9 million, which reduced the carrying value of these properties to their aggregate fair value of $62.5 million. In the first quarter of 2010, we impaired three of our natural gas producing properties following a significant drop in natural gas prices during the period. The total amounts of the impairment charges were $7.0 million, which reduced these properties to their aggregate fair value of $28.2 million. See Note 4 for additional information regarding our oil and gas property impairment charges.

Note 16 – Derivative Instruments and Hedging Activities

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

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

For additional information regarding our accounting for derivatives see Notes 2 and 20 of our 2010 Form 10-K.

Commodity Price Risks

We currently manage commodity price risk through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production through 2013. All of our current commodity derivative contracts qualify for hedge accounting. In June 2010, oil contracts for 480 MBbl, representing a portion of our anticipated production during the third quarter of 2010, ceased to qualify for hedge accounting as a result of our decision to contract the HP I to assist in the Gulf oil spill response and containment efforts rather than commencing production from our Phoenix field. In September 2010, we separately concluded that oil contracts covering an additional 480 MBbls of the fourth quarter 2010 anticipated production ceased to qualify for hedge accounting because of uncertainty as to when the Phoenix field would be ready to commence initial production following extensions of the HP I contract to assist in the Gulf oil spill response and containment efforts. The HP I returned to the Phoenix field in October and initial production from the field commenced on October 19, 2010.

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As of September 30, 2011, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 4.5 MMBbl of oil and 8.1 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
October 2011 — December 2011	Swap	163.3 MBbl	82.62
October 2011 — December 2011	Collar	35.3 MBbl	$ 95.00 — $124.59
October 2011 — December 2011	Collar	50.0 MBbl	$100.00 — $122.80 a
January 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57
January 2012 — December 2012	Collar	139.0 MBbl	$ 99.42 — $117.59 a
January 2012 — December 2012	Swap	16.0 MBbl	$103.20 a
January 2013 — December 2013	Swap	41.7 MBbl	$ 99.15 a
January 2013 — December 2013	Collar	41.7 MBbl	$ 95.00 — $102.60a
Natural Gas:			(per Mcf)
October 2011 — December 2011	Swap	703.3 Mmcf	$4.93
January 2012 — December 2012	Swap	333.3 Mmcf	$4.70
January 2012 — December 2012	Collar	166.7 Mmcf	$4.75 — $5.09

a. The prices quoted in the table above are primarily NYMEX Henry Hub for natural gas and NYMEX West Texas Intermediate for crude oil. As footnoted above these costless collar contracts are priced as Brent crude oil.

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

Variable Interest Rate Risks

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

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds. The last of our existing monthly foreign currency swap contracts will settle in June 2012.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of September 30, 2011 and December 31, 2010. The fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

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Derivatives designated as hedging instruments are as follows:

	As of September 30, 2011 Balance Sheet Location	Fair Value	As of December 31, 2010 Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Oil contracts	Other current assets	$28,020	Other current assets	$—
Natural gas contracts	Other current assets	5,074	Other current assets	5,324
Natural gas contracts	Other assets, net	322	Other assets, net	—
Oil contracts	Other assets, net	8,868	Other assets, net	—
Interest rate swaps	Other assets, net	238	Other assets, net	—
		$42,522		$5,324

	As of September 30, 2011 Balance Sheet Location	Fair Value	As of December 31, 2010 Balance Sheet Location	Fair Value
		(in thousands)		
Liability Derivatives:				
Oil contracts	Accrued liabilities	$—	Accrued liabilities	$28,855
Interest rate swaps	Accrued liabilities	692	Accrued liabilities	1,751
Natural gas contracts	Other long-term liabilities	—	Other long-term liabilities	913
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	115
		$692		$31,634

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

	As of September 30, 2011 Balance Sheet Location	Fair Value	As of December 31, 2010 Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Foreign exchange forwards	Other current assets	$109	Other current assets	$148
Foreign exchange forwards	Other assets, net	—	Other assets, net	42
		$109		$190
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	264	Accrued liabilities	—
		$264		$—

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive loss and our condensed consolidated statements of operations for the three and nine month periods ended September 30, 2011 and 2010.

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011(1)	2010(1)	2011(1)	2010(1)
	(in thousands)			
Oil and natural gas commodity contracts	$ 33,432	$ (3,405)	$ 43,373	$ 13,799
Interest rate swaps	456	(390)	918	(1,491)
	$ 33,888	$ (3,795)	$ 44,291	$ 12,308

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(1) All unrealized gains (losses) related to our oil and natural gas commodity contracts are expected to be reclassified into earnings by no later than December 31, 2013. The last of our interest swaps will mature in January 2014 and we have foreign exchange forwards that have maturities through June 2012.

	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 September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Oil and natural gas commodity contracts	Oil and gas revenue	$ (1,287)	$ 7,428	$ (19,473)	$ 17,892
Interest rate swaps	Net interest expense	(522)	(468)	(1,513)	(1,355)
		$ (1,809)	$ 6,960	$ (20,986)	$ 16,537

The following table presents the impact of derivative instruments that no longer qualify for hedge accounting or were not designated as hedges in our condensed consolidated statements of operations for the three and nine month periods ended September 30, 2011 and 2010:

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
		(in thousands)			
Natural gas contracts	Gain on oil and gas derivative contracts	$ —	$ 161	$ —	$ 2,643
Foreign exchange forwards	Other income (expense)	(381)	1,106	(234)	(2,398)
		$ (381)	$ 1,267	$ (234)	$ 245

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

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

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

	As of September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 335,063	$ 1,060	$ 39,232	$ —	$ 375,355
Accounts receivable, net	76,595	92,881	51,686	—	221,162
Unbilled revenue	13,235	18	15,621	—	28,874
Income taxes receivable	39,013	—	2,691	(41,704)	—
Other current assets	60,957	49,739	13,832	(1,292)	123,236
Total current assets	524,863	143,698	123,062	(42,996)	748,627
Intercompany	(16,546)	276,281	(210,909)	(48,826)	—
Property and equipment, net	219,450	1,552,025	707,165	(4,887)	2,473,753
Other assets:					
Equity investments in unconsolidated affiliates	—	—	186,423	—	186,423
Equity investments in affiliates	1,989,756	35,708	—	(2,025,464)	—
Goodwill, net	—	45,107	17,237	—	62,344
Other assets, net	46,672	45,977	17,625	(29,412)	80,862
Due from subsidiaries/parent	82,918	331,591	—	(414,509)	—
	$ 2,847,113	$ 2,430,387	$ 840,603	$ (2,566,094)	$ 3,552,009
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 42,650	$ 74,003	$ 28,459	$ —	$ 145,112

Accrued liabilities	50,000	81,412	28,264	—	159,676
Income taxes payable	—	62,870	—	(59,014)	3,856
Current maturities of long-term debt	3,000	—	4,877	—	7,877
Total current liabilities	95,650	218,285	61,600	(59,014)	316,521
Long-term debt	1,058,626	—	105,288	—	1,163,914
Deferred income taxes	227,047	120,838	99,249	(5,614)	441,520
Asset retirement obligations	—	169,429	—	—	169,429
Other long-term liabilities	1,351	2,899	594	—	4,844
Due to parent	—	—	108,403	(108,403)	—
Total liabilities	1,382,674	511,451	375,134	(173,031)	2,096,228
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,463,439	1,918,936	465,469	(2,393,063)	1,454,781
	$ 2,847,113	$ 2,430,387	$ 840,603	$ (2,566,094)	$ 3,552,009

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

	As of December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$376,434	$3,294	$11,357	$—	$391,085
Accounts receivable, net	61,846	91,659	23,788	—	177,293
Unbilled revenue	11,990	—	37,421	—	49,411
Income taxes receivable	19,334	—	7,195	(20,430)	6,099
Other current assets	63,306	49,557	12,889	(8,786)	116,966
Total current assets	532,910	144,510	92,650	(29,216)	740,854
Intercompany	1,906	263,920	(171,513)	(94,313)	—
Property and equipment, net	217,153	1,605,906	709,082	(5,061)	2,527,080
Equity investments in unconsolidated affiliates	—	—	187,031	—	187,031
Equity investments in affiliates	1,998,289	29,899	—	(2,028,188)	—
Goodwill, net	—	45,107	17,387	—	62,494
Other assets, net	43,971	38,324	21,900	(29,634)	74,561
Due from subsidiaries/parent	95,398	105,434	—	(200,832)	—
	$2,889,627	$2,233,100	$856,537	$(2,387,244)	$3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$60,308	$56,107	$42,966	$—	$159,381
Accrued liabilities	58,074	107,874	32,289	—	198,237
Income taxes payable	—	36,678	—	(36,678)	—
Current maturities of	4,326	—	14,301	(8,448)	10,179

long-term debt					
Total current liabilities	122,708	200,659	89,556	(45,126)	367,797
Long-term debt	1,237,587	—	110,166	—	1,347,753
Deferred income taxes	185,453	135,101	98,968	(5,883)	413,639
Asset retirement obligations	—	170,410	—	—	170,410
Other long-term liabilities	1,421	3,691	665	—	5,777
Due to parent	—	—	120,884	(120,884)	—
Total liabilities	1,547,169	509,861	420,239	(171,893)	2,305,376
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,341,458	1,723,239	436,298	(2,215,351)	1,285,644
	$2,889,627	$2,233,100	$856,537	$(2,387,244)	$3,592,020

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

	Three Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$19,986	$266,447	$ 109,780	$ (23,717)	$ 372,496
Cost of sales	15,698	182,259	75,643	(23,399)	250,201
Gross profit (loss)	4,288	84,188	34,137	(318)	122,295
Gain on oil & gas derivative contracts	—	—	—	—	—
Gain (loss) on sale or acquisition of assets	—	—	—	—	—
Selling, general and administrative expenses	(6,752)	(9,551)	(6,105)	326	(22,082)
Income (loss) from operations	(2,464)	74,637	28,032	8	100,213
Equity in earnings of investments	60,831	7,277	4,906	(68,108)	4,906
Net interest expense and other	(17,612)	(8,016)	(9,200)	—	(34,828)
Income (loss) before income taxes	40,755	73,898	23,738	(68,100)	70,291
Provision (benefit) for income taxes	(5,266)	24,419	4,309	3	23,465
Net income (loss), including noncontrolling interests	46,021	49,479	19,429	(68,103)	46,826
Less net income applicable to noncontrolling interests	—	—	—	(800)	(800)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$46,011	$49,479	$ 19,429	$ (68,903)	$ 46,016

	Three Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 82,764	$ 212,105	$ 111,581	$ (13,781)	$ 392,669
Cost of sales	42,397	184,369	92,765	(13,414)	306,117
Gross profit (loss)	40,367	27,736	18,816	(367)	86,552
Gain on oil & gas derivative contracts	—	161	—	—	161
Gain (loss) on sale or acquisition of assets	—	—	13	—	13
Selling, general and administrative expenses	(15,465)	(7,370)	(4,212)	419	(26,628)
Income (loss) from operations	24,902	20,527	14,617	52	60,098

Equity in earnings of investments	27,871	7,567	6,221	(35,438)	6,221
Net interest expense and other	(19,452)	(3,996)	2,041	—	(21,407)
Income (loss) before income taxes	33,321	24,098	22,879	(35,386)	44,912
Provision (benefit) for income taxes	7,185	4,530	6,234	16	17,965
Net income (loss), including noncontrolling interests	26,136	19,568	16,645	(35,402)	26,947
Less net income applicable to noncontrolling interests	—	—	—	(776)	(776)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$ 26,126	$ 19,568	$ 16,645	$ (36,178)	$ 26,161

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

	Nine Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$56,113	$756,344	$ 260,582	$ (70,617)	$ 1,002,422
Cost of sales	47,414	521,387	203,651	(69,599)	702,853
Gross profit (loss)	8,699	234,957	56,931	(1,018)	299,569
Gain on oil & gas derivative contracts	—	—	—	—	—
Gain (loss) on sale or acquisition of assets	(6)	—	—	—	(6)
Selling, general and administrative expenses	(27,512)	(29,502)	(14,917)	1,110	(70,821)
Income (loss) from operations	(18,819)	205,455	42,014	92	228,742
Equity in earnings of investments	167,867	5,809	16,443	(173,676)	16,443
Net interest expense and other	(53,139)	(18,615)	(8,675)	—	(80,429)
Income (loss) before income taxes	95,909	192,649	49,782	(173,584)	164,756
Provision (benefit) for income taxes	(17,229)	66,479	(95)	31	49,186
Net income (loss), including noncontrolling interests	113,138	126,170	49,877	(173,615)	115,570
Less net income applicable to noncontrolling interests	—	—	—	(2,354)	(2,354)
Preferred stock dividends	(30)	—	—	—	(30)
Net income (loss) applicable to Helix common shareholders	$113,108	$126,170	$ 49,877	$ (175,969)	$ 113,186

	Nine Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 137,456	$ 568,075	$ 256,639	$ (68,669)	$ 893,501
Cost of sales	73,889	641,568	215,067	(54,613)	875,911
Gross profit (loss)	63,567	(73,493)	41,572	(14,056)	17,590
Gain on oil & gas derivative contracts	—	2,643	—	—	2,643
Gain (loss) on sale or acquisition of assets	—	287	5,959	—	6,246
	(52,923)	(25,285)	(14,788)	1,321	(91,675)

Selling, general and administrative expenses					
Income (loss) from operations	10,644	(95,848)	32,743	(12,735)	(65,196)
Equity in earnings of investments	(36,865)	10,672	12,932	26,193	12,932
Net interest expense and other	(42,160)	(16,564)	(6,102)	—	(64,826)
Income (loss) before income taxes	(68,381)	(101,740)	39,573	13,458	(117,090)
Provision (benefit) for income taxes	517	(40,606)	2,584	(4,457)	(41,962)
Net income (loss), including noncontrolling interests	(68,898)	(61,134)	36,989	17,915	(75,128)
Less net income applicable to noncontrolling interests	—	—	—	(2,049)	(2,049)
Preferred stock dividends	(104)	—	—	—	(104)
Net income (loss) applicable to Helix common shareholders	$ (69,002)	$ (61,134)	$ 36,989	$ 15,866	$ (77,281)

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

	Nine Months Ended September 30, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ 113,138	$ 126,170	$ 49,877	$ (173,615)	$ 115,570
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(167,867)	(5,809)	—	173,676	—
Other adjustments	19,125	218,602	2,578	(4,744)	235,561
Net cash provided by (used in) operating activities	(35,604)	338,963	52,455	(4,683)	351,131
Cash flows from investing activities:					
Capital expenditures	(18,240)	(129,535)	(20,074)	—	(167,849)
Investments in equity investments	—	—	(2,699)	—	(2,699)
Distributions from equity investments, net	—	—	3,437	—	3,437
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Decrease (increase) in restricted cash	—	703	—	—	703
Net cash used in investing activities	(14,652)	(128,832)	(19,336)	—	(162,820)
Cash flows from financing activities:					
Repayments of debt	(111,941)	—	(5,860)	—	(117,801)
Extinguishment of Senior Unsecured Notes	(77,394)	—	—	—	(77,394)

Deferred financing costs	(9,224)	—	—	—	(9,224)
Repurchase of common stock and preferred dividends paid	(1,102)	—	—	—	(1,102)
Excess tax benefit from stock-based compensation	(805)	—	—	—	(805)
Exercise of stock options, net	2,018	—	—	—	2,018
Intercompany financing	207,333	(212,365)	349	4,683	—
Net cash provided by (used in) financing activities	8,885	(212,365)	(5,511)	4,683	(204,308)
Effect of exchange rate changes on cash and cash equivalents	—	—	267	—	267
Net increase (decrease) in cash and cash equivalents	(41,371)	(2,234)	27,875	—	(15,730)
Cash and cash equivalents:					
Balance, beginning of year	376,434	3,294	11,357	—	391,085
Balance, end of period	$ 335,063	$ 1,060	$ 39,232	$ —	$ 375,355

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

	Nine Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ (68,898)	$ (61,134)	$ 36,989	$ 17,915	$ (75,128)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	36,866	(10,673)	—	(26,193)	—
Other adjustments	70,963	229,567	33,675	(17,311)	316,894
Net cash provided by (used in) operating activities	38,931	157,760	70,664	(25,589)	241,766
Cash flows from investing activities:					
Capital expenditures	(54,880)	(104,423)	(19,715)	—	(179,018)
Investments in equity investments	—	—	(7,768)	—	(7,768)
Distributions from equity investments, net	—	—	9,876	—	9,876
Insurance recovery	7,020	9,086	—	—	16,106
Proceeds from sale of property	—	852	—	—	852
Decrease (increase) in restricted cash	—	(133)	—	—	(133)
Net cash used in investing activities	(47,860)	(94,618)	(17,607)	—	(160,085)
Cash flows from financing activities:					
Repayments of debt	(3,245)	—	(6,708)	—	(9,953)
Deferred financing costs	(2,864)	—	—	—	(2,864)
Repurchases of common stock	(11,763)	—	—		(11,763)
Excess tax benefit from stock-based compensation	(2,376)	—	—	—	(2,376)
Exercise of stock options, net	335	—	—	—	335
Intercompany financing	73,887	(61,811)	(37,665)	25,589	—

Net cash provided by (used in) financing activities	53,974	(61,811)	(44,373)	25,589	(26,621)
Effect of exchange rate changes on cash and cash equivalents	—	—	(253)	—	(253)
Net increase (decrease) in cash and cash equivalents	45,045	1,331	8,431	—	54,807
Cash and cash equivalents:					
Balance, beginning of year	258,742	2,522	9,409	—	270,673
Balance, end of period	$ 303,787	$ 3,853	$ 17,840	$ —	$ 325,480

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

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

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- impact of weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- the effect of new regulations on the offshore Gulf of Mexico oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt, and could have other adverse consequences to us;
- the effectiveness of our hedging activities;
- the results of our continuing efforts to control or reduce costs, and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations and the terms of any such financing;
- the impact of current and future laws and governmental regulations including tax and accounting developments;
- the effect of adverse weather conditions or other risks associated with marine operations;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those described in Item 1A. “Risk Factors” in our 2010 Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

EXECUTIVE SUMMARY

Our Business

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

Our Strategy

Over the past few years, we have focused on improving our balance sheet by increasing our liquidity through disposition of non-core business assets, decreases in our planned capital spending and reductions in the amount of our debt outstanding. In June 2011, we amended our Credit Agreement to extend its maturity to at least July 1, 2015 and to increase the amount we can potentially borrow under the Revolving Credit Facility to $600 million. For complete information regarding our fourth amendment to our Credit Agreement see Note 7 included elsewhere herein. In the third quarter of 2011, we reduced our debt by $75.9 million, including the repurchase and extinguishment of $75.0 million of our Senior Unsecured Notes. At September 30, 2011, our cash on hand totaled $375.4 million and our liquidity was $932.7 million. Our capital expenditures for full year 2011 are expected to total approximately $275 million (but is exclusive of expenditures related to our asset retirement obligations). Although we are in the preliminary stages of preparing our capital budget for 2012, we expect that a total of five of our subsea construction and well intervention vessels will be required to be sent to regulatory dry dock at some point during the year. The scope and cost of those projects is still being evaluated. Over the coming twelve months, we believe that we have sufficient liquidity to successfully implement our business plan without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

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In March 2010, we announced the engagement of advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. As previously disclosed, certain events in the Gulf of Mexico compromised the efforts to dispose of our entire oil and gas business. As a result, we are no longer actively seeking to divest our oil and gas business and have shifted our strategy to develop our significant proved undeveloped reserve portfolio and drill certain of our exploration prospects with a focus on crude oil prospects given the favorable price environment for this commodity. We may from time to time sell certain of our individual oil and gas properties that we consider to be in our best interest in terms of economic returns and/or risk mitigation.

Economic Outlook and Industry Influences

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

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

Oil prices increased significantly in 2011 (the average WTI price was $98.33 per barrel in the first half of 2011) but decreased during the latter portions of the third quarter of 2011 (the WTI price in late September 2011 approximated $80 per barrel). Beginning in the latter part of the first quarter of 2011, the price that we received for the majority of our crude oil sales volumes increased significantly over the WTI market price (by anywhere from $11-$15 per barrel). Historically the price we receive for most of our crude oil, as priced using a number of Gulf Coast crude oil price indexes, closely correlated with current market prices of WTI crude oil; however, because of a substantial increase in crude oil inventories at Cushing, Oklahoma the price of Gulf Coast crude is now substantially higher than WTI. Currently the price we receive for our crude oil more closely correlates with the Brent crude oil price in the

North Sea. We do not know how long the price variance of our crude oil and WTI will continue but most analysts believe this will continue over at least the remainder of 2011 and into 2012.

Prices for natural gas have decreased significantly from the record highs in mid 2008 primarily reflecting the increased supply from non-traditional sources of natural gas such as production from shale formations and tight sands, as well as decreased demand following the economic downturn that commenced in mid-to-late 2008. Although there have been signs that the economy may be slightly improving, most economists believe the recovery will be slow and will take time to recover to previous levels. 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 more recent uncertainties concerning increased government regulation of the industry in the United States (as further discussed below).

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In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252 (Note 1). The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S. territorial waters. In October 2010, the DOI lifted the drilling moratorium and instructed the BOEMRE that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. The BOEMRE resumed issuing deepwater drilling permits in late February 2011. See below for a discussion of our Helix Fast Response System, which currently represents one of two containment systems that have been included in deepwater drilling permit applications with BOEMRE under its new guidelines.

While we did not have plans to drill any additional deepwater wells during the period covered by the drilling moratorium, our contracting services businesses rely heavily on industry investment in the Gulf of Mexico and the results of the moratorium and subsequent delay in the drilling permit process has adversely affected our results of operations and financial position. Although our contracting services activities during 2010 remained substantially unaffected, delays in restarting drilling in the deepwater of the Gulf of Mexico, due to the failure to issue permits or otherwise, have resulted in a deferral or cancellation of portions of our contracted backlog and have decreased current opportunities for contracts for work in the Gulf of Mexico and may continue to affect future opportunities for work in the Gulf of Mexico. Furthermore, the continuing delays in the permitting process and any subsequent related developments in the Gulf of Mexico could require us to pursue relocation of our vessels located in the Gulf of Mexico to international locations, such as the North Sea, West Africa, Southeast Asia, Brazil and Mexico.

Although we are still feeling the effects of a relatively fragile global economy and are experiencing the consequences of the additional regulatory requirements resulting from the aftermath of the oil spill in the Gulf of Mexico, 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 requires the need for continual replenishment of oil and gas production; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing global offshore activity, particularly in deepwater; and (6) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an ownership stake.

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.

Helix Fast Response System

We developed the Helix Fast Response System ("HFRS") as a culmination of our experience as a responder in the Gulf oil spill response and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Gulf oil spill response and containment efforts and are presently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available for a two-year term to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS solution be deployed in connection with a well control incident. The retainer fee associated with HFRS was effective April 1, 2011 and is a component of our Production Facilities business segment. A total of 38 permits have been granted to CGA participants for deepwater drilling operations identifying the HFRS to fulfill the BOERME requirement to have a spill response and containment resource included in the submitted permit applications.

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RESULTS OF OPERATIONS

We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our third business segment, Oil and Gas, represents our operations within that industry. 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 finding and developing offshore reservoirs and maximizing production economics. Our Contracting Services segment includes operations such as subsea construction, deepwater pipelay, well operations and robotics. 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. Our Production Facilities business includes our investments in Deepwater Gateway and Independence Hub as well as our majority ownership of the HP I. Our Production Facilities segment also includes the HFRS retainer fee (see "Helix Fast Response System" above). As of September 30, 2011, our Contracting Services operations had backlog of approximately $425.3 million, including $198.8 million for the remainder of 2011 and $207.0 million for 2012. Backlog for the HP I totaled $57.7 million at September 30, 2011, including $8.4 million for the remainder of 2011 and $33.3 million for 2012. At December 31, 2010, our contracting services operations backlog totaled approximately $267.3 million, including $218.8 million for 2011. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services and Production Facilities businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

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

Impairments

In the third quarter of 2011, we recorded a total of $2.4 million of impairment charges primarily related to revisions in cost estimates for reclamation activities ongoing at two of our Gulf of Mexico oil and gas properties. During the three-month period ended June 30, 2011, we recorded impairment charges totaling $22.7 million, including $4.1 million for our only United Kingdom oil and gas property, and for six of our Gulf of Mexico oil and gas properties. These impairment charges primarily reflect a premature end of these fields' production life either through actual depletion or capital allocation decisions affecting our third party operated fields. We did not have any impairment of our properties in the either the first or third quarters of 2011. Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. See Note 4 for more information regarding our impairment charges.

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Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as one that purports to measure historical or future performance, financial position, or cash flows, but excludes amounts that would not be so adjusted in the most comparable measures under generally accepted accounting principles (GAAP). We measure our operating performance based on EBITDAX, a non-GAAP financial measure, that is commonly used in the oil and natural gas industry but is not a recognized accounting term under GAAP. We use EBITDAX to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required under our debt covenants. We believe our measure of EBITDAX provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and make it easier to compare our results to other companies that have different financing, capital and tax structures.

We define EBITDAX as income (loss) from continuing operations plus income taxes, net interest expense and other, depreciation, depletion and amortization expense and exploration expenses. We separately disclose our non cash oil and gas property impairment charges, which, if not material, would be reflected as a component of our depreciation, depletion and amortization expense. Because such impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non cash impairment charges related to goodwill are also added back if applicable.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Income (loss), including noncontrolling interests	$ 46,826	$ 26,947	$115,570	$ (75,128)
Adjustments:				
Income tax provision (benefit)	23,465	17,965	49,186	(41,962)
Net interest expense and other	34,828	21,407	81,182	64,826

Depreciation, depletion and amortization expense	72,370	76,462	239,540	222,730
Asset impairment charges	2,357	897	25,078	171,871
Exploration expenses	1,548	442	9,833	1,780
EBITDAX	181,394	144,120	520,389	344,117
Adjustments:				
Non-controlling interest Kommandor LLC	(1,035)	(1,035)	(3,076)	(2,840)
Discontinued operations	—	—	—	(15)
(Gain) loss on sales of assets		(13)	(747)	(6,246)
Asset retirement costs	(2,357)	(897)	(13,505)	(897)
ADJUSTED EBITDAX	$ 178,002	$ 142,175	$ 503,061	$ 334,119

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Comparison of Three Months Ended September 30, 2011 and 2010

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$229,967	$238,531	$ (8,564)
Production Facilities	19,986	74,458	(54,472)
Oil and Gas	159,218	95,566	63,652
Intercompany elimination	(36,675)	(15,886)	(20,789)
	$372,496	$392,669	$ (20,173)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 55,799	$ 42,149	$ 13,650
Production Facilities	11,072	44,616	(33,544)
Oil and Gas	56,631	1,083	55,548
Corporate	(679)	(1,010)	331
Intercompany elimination	(528)	(286)	(242)
	$122,295	$ 86,552	$ 35,743
Gross Margin –			
Contracting Services	24%	18%	6 pts
Production Facilities	55%	60%	(5)pts
Oil and Gas	36%	1%	35pts
Total company	33%	22%	11pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/86%	8/97%	
Well operations	3/99%	4/83%	
ROVs	46/67%	46/68%	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.
(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the three-month periods ended September 30, 2011 and 2010 were as follows (in thousands):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease)

Contracting Services	$ 25,410	$ 15,886	$ 9,524
Production Facilities	11,265	—	11,265
	$ 36,675	$ 15,886	$ 20,789

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Intercompany segment profit during the three-month periods ended September 30, 2011 and 2010 was as follows (in thousands):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease)
Contracting Services	$ 606	$ 330	$ 276
Production Facilities	(78)	(44)	(34)
	$ 528	$ 286	$ 242

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	1,343	751	592
Oil sales revenue (in thousands)	$ 135,590	$ 55,314	$ 80,276
Average oil sales price per Bbl (excluding hedges)	$ 103.20	$ 74.68	$ 28.52
Average realized oil price per Bbl (including hedges)	$ 100.93	$ 73.63	$ 27.30
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 20,506		
Change in production volume (in thousands)	59,770		
Total increase in oil sales revenue (in thousands)	$ 80,276		
Gas production volume (MMcf)	3,617	5,875	(2,258)
Gas sales revenue (in thousands)	$ 22,244	$ 36,039	$ (13,795)
Average gas sales price per mcf (excluding hedges)	$ 5.66	$ 4.74	$ 0.92
Average realized gas price per mcf (including hedges)	$ 6.15	$ 6.13	$ 0.02
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 92		
Change in production volume (in thousands)	(13,887)		
Total decrease in gas sales revenue (in thousands)	$ (13,795)		

Total production (MMcfe)	11,678	10,383	1,295
Price per Mcfe	$ 13.52	$ 8.80	$ 4.72
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 157,834	$ 91,352	$ 66,482
Other revenues(1)	1,384	4,214	(2,830)
	$ 159,218	$ 95,566	$ 63,652

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

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

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	Three Months Ended September 30,			
	2011		2010	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 38,022	$ 3.26	$ 27,406	$ 2.64
Workover	3,737	0.32	3,701	0.36
Transportation	1,816	0.15	1,889	0.18
Repairs and maintenance	2,369	0.20	2,646	0.25
Overhead and company labor	2,709	0.23	1,992	0.19
	$ 48,653	$ 4.16	$ 37,634	$ 3.62
Depletion expense	$ 46,008	$ 3.94	$ 50,677	$ 4.88
Abandonment	671	0.06	150	0.01
Accretion expense	3,622	0.31	3,743	0.36
Net hurricane costs (reimbursements)	(272)	(0.02)	940	0.09
Impairment	2,357	0.20	897	0.09
	52,386	4.49	56,407	5.43
Total	$ 101,039	$ 8.65	$ 94,041	$ 9.05

(1) Excludes exploration expense of $1.5 million and $0.4 million for the three-month periods ended September 30, 2011 and 2010, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. Our Contracting Services revenues decreased 4% for the three-month period ended September 30, 2011 compared to the same period in 2010 reflecting decreased subsea construction activity in the Gulf of Mexico, primarily attributable to delays in permitting of projects since the Gulf oil spill in April 2010. Overall utilization levels for subsea construction assets were negatively impacted for the third quarter of 2011 as the Caesar continued its capital upgrades at a U.S. shipyard until mid-October 2011. The Caesar has mobilized to Mexico for an accommodations project. Our ROV utilization rate remained substantially unchanged on the same number of units. The decrease in our utilization rates for our pipelay and robotics support vessels primarily reflects the lower number of projects with approved permits in the Gulf of Mexico region. Demand for our well intervention vessels remains strong in both the Gulf of Mexico and North Sea regions with near full utilization during the third quarter of 2011. Our third quarter 2010 revenues included amounts earned by the contracting of the Q4000, the Express and the HP I to assist in the Gulf oil spill response and containment efforts.

Oil and Gas revenues increased 67% during the three-month period ended September 30, 2011 as compared to the same period in 2010. The increase in revenues reflects increased oil production and higher oil prices. Our production was 1.3 billion cubic feet of natural gas equivalent (Bcfe) more in the third quarter of 2011 as compared to the same period in 2010, primarily reflecting oil production from our Phoenix field at Green Canyon Blocks 236, 237, 238 and 282 which commenced production in October 2010, offset in part by lower natural gas production, most notably from our Bushwood field. Our production was adversely affected during the third quarter of 2011 as the Phoenix field was shut in for a portion of July due to scheduled downtime of a third party pipeline servicing the Phoenix field and the fields in the vicinity. Additionally, a substantial amount of our production was affected by Tropical Storm Lee in early September 2011. Our net production rate through October 23, 2011 approximated 128 MMcfe/d as compared to an approximate average of 127 MMcfe/d for the three-month period ended September 30, 2011.

Our Production Facilities revenues reflect the HP I being placed in service in June 2010, following the final installation of its production processing facility upgrades and receipt of its certification by U.S. Coast Guard. The HP I was initially used in the Gulf oil spill response and containment efforts where it remained until October 2010 at which time it moved to our Phoenix field in which we own a 70% working interest. The HP I continues to be utilized in the Phoenix field, where it is expected to remain until at least 2013. Our revenues also include the quarterly retainer fee associated with the HFRS.

Gross Profit. Our Contracting Services gross profit increased by 32% in the three-month period ended September 30, 2011 as compared to the same period last year. This increase primarily reflected improved well intervention vessel utilization, partially offset by the weak subsea construction industry conditions in the Gulf of Mexico region, which contributed significantly to our lower pipelay and robotics support vessel and ROV utilization rates. Our gross profit margin in the third quarter of 2010 benefitted

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from the Express and Q4000 being on hire in the Gulf oil spill response and containment efforts while it was adversely affected by $20.5 million of losses related to two projects, including the initial pipelay project performed by the Caesar.

Oil and Gas gross profit increased by $55.5 million for the three-month period ended September 30, 2011 as compared to the same period in 2010, which was primarily attributable to increased oil production and higher oil price realizations. The increase in our production is primarily related to the commencement of production from our Phoenix field in October 2010.

Our gross profit for Production Facilities decreased for the three-month period ended September 30, 2011, as compared to same period in 2010, reflecting the current deployment of the HP I in the Phoenix field, which is owned 70% by us, as compared to the vessel's third party utilization in the Gulf oil spill response and containment efforts in the third quarter of 2010. Our gross profit for the three-month period ended September 30, 2011 also benefitted from the quarterly HFRS retainer fee.

Selling, General and Administrative Expenses. Selling, general and administrative expenses of $22.1 million for the third quarter of 2011 were $4.5 million lower than the $26.6 million incurred in the same prior year period. The decrease reflects implementation of certain cost savings initiatives and lower long term incentive costs (Note 11).

Equity in Earnings of Investments. Equity in earnings of investments decreased by $1.3 million during the three-month period ended September 30, 2011 as compared to the same prior year period. This decrease was primarily due to lower throughput at both Deepwater Gateway and Independence Hub, reflecting lower production for the fields serviced by the respective facilities, including the disruptions caused by Tropical Storm Lee in early September 2011. Our equity earnings also reflect lower contribution from our Clough Helix JV in Australia as work in China was slightly less profitable in third quarter of 2011 than in same period last year due to weather disruptions.

Net Interest Expense. Our net interest expense was $24.1 million in third quarter 2011 as compared to $25.5 million in the same prior year period. Gross interest expense of $25.2 million during the three-month period ended September 30, 2011 was less than the $25.8 million incurred in the comparable 2010 period reflecting repayments on our Term Loan and the early extinguishment of $75.0 of our Senior Unsecured Notes. Our interest expense for the three-month period ended September 30, 2011 also included $0.9 million of charges to accelerate the amortization of a pro rata portion of the deferred financing costs associated with the early extinguishment of a portion of our Senior Unsecured Notes (Note 7). Interest income totaled $0.6 million for the three-month period ended September 30, 2011, as compared with $0.3 million in the same prior year period, reflecting our higher cash balances.

Other Income (Expense). The $14.8 million variance in other expense for the three-month period ended September 30, 2011 compared with the same prior year period primarily reflects foreign exchange fluctuations in our non U.S. dollar functional currencies and foreign exchange currency contracts. During the third quarter of 2011 the strengthening of the U.S. dollar against other global currencies resulted in our recording foreign exchange losses totaling $8.3 million as compared to recording foreign exchange gains of $3.1 million in third quarter of 2010. We had $0.4 million of losses on our foreign exchange forward contracts in the third quarter of 2011 compared to gains of $1.1 million in the third quarter of 2010 (Note 16). Separately, during the third quarter of 2011 we repurchased approximately $75 million of our Senior Unsecured Notes (Note 7). The $2.4 million premium we paid to early extinguish those notes was charged to other expense.

Provision for Income Taxes. We recorded income taxes expense of $23.5 million in the third quarter of 2011, as compared to $18.0 million in the same prior year period. The variance primarily reflects increased profitability in the current year period. The effective tax rate for the third quarter of 2011 was 33.4% as compared to 40.0% for the third quarter of 2010 reflecting the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions.

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Comparison of Nine Months Ended September 30, 2011 and 2010

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 532,857	$ 595,048	$ (62,191)
Production Facilities	56,101	97,169	(41,068)
Oil and Gas	500,535	288,867	211,668
Intercompany elimination	(87,071)	(87,583)	512
	$1,002,422	$ 893,501	$ 108,921
Gross profit (loss) (in thousands) –			
Contracting Services	$ 104,360	$ 130,104	$ (25,744)
Production Facilities	29,278	57,715	(28,437)
Oil and Gas	168,724	(149,036)	317,760
Corporate	(2,336)	(2,471)	135
Intercompany elimination	(457)	(18,722)	18,265
	$ 299,569	$ 17,590	$ 281,979
Gross Margin –			
Contracting Services	20%	22%	(2)pts
Production Facilities	52%	59%	(7)pts
Oil and Gas	34%	(52)%	86pts
Total company	30%	2%	28pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/70%	8/84%	
Well operations	3/88%	4/81%	
ROVs	46/57%	46/63%	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.
(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the nine-month periods ended September 30, 2011 and 2010 were as follows (in thousands):

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Increase/ (Decrease)

Contracting Services	$ 52,574	$ 84,053	$ (31,479)
Production Facilities	34,497	3,530	30,967
	$ 87,071	$ 87,583	$ (512)

Intercompany segment profit during the nine-month periods ended September 30, 2011 and 2010 was as follows (in thousands):

	Nine Months Ended September 30, 2011	2010	Increase/ (Decrease)
Contracting Services	$ 645	$ 15,473	$ (14,828)
Production Facilities	(188)	3,249	(3,437)
	$ 457	$ 18,722	$ (18,265)

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	4,275	2,196	2,079
Oil sales revenue (in thousands)	$416,500	$159,688	$ 256,812
Average oil sales price per Bbl (excluding hedges)	$ 103.69	$ 75.24	$ 28.45
Average realized oil price per Bbl (including hedges)	$ 97.43	$ 72.71	$ 24.72
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 54,280		
Change in production volume (in thousands)	202,532		
Total increase in oil sales revenue (in thousands)	$256,812		
Gas production volume (MMcf)	13,094	20,365	(7,271)
Gas sales revenue (in thousands)	$ 78,527	$121,814	$ (43,287)
Average gas sales price per mcf (excluding hedges)	$ 5.44	$ 4.83	$ 0.61
Average realized gas price per mcf (including hedges)	$ 6.00	$ 5.98	$ 0.02
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 317		
Change in production volume (in thousands)	(43,604)		
Total decrease in gas sales revenue (in thousands)	$ (43,287)		
Total production (MMcfe)	38,743	33,541	5,202
Price per Mcfe	$ 12.78	$ 8.39	$ 4.39
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$495,027	$281,502	$ 213,525
Other revenues(1)	5,508	7,365	(1,857)
	$500,535	$288,867	$ 211,668

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

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

	Nine Months Ended September 30,			
	2011		2010	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 98,072	$ 2.53	$ 57,728	$ 1.72
Workover	8,541	0.22	18,818	0.56
Transportation	5,618	0.14	4,218	0.13
Repairs and maintenance	7,616	0.20	6,179	0.18
Overhead and company labor	9,322	0.24	5,465	0.16
	$ 129,169	$ 3.33	$ 92,408	$ 2.75
Depletion expense	$ 160,247	$ 4.14	$ 154,283	$ 4.60
Abandonment	1,056	0.03	1,316	0.04
Accretion expense	11,252	0.29	11,686	0.35
Net hurricane costs (reimbursements)	(4,824)	(0.13)	4,559	0.14
Impairment	25,078	0.65	171,871	5.12
	192,809	4.98	343,715	10.25
Total	$ 321,978	$ 8.31	$ 436,123	$ 13.00

(1) Excludes exploration expense of $9.8 million and $1.8 million for the nine-months periods ended September 30, 2011 and 2010, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

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Revenues. Our Contracting Services revenues decreased 10% for the nine-month period ended September 30, 2011 compared to the same period in 2010 reflecting the decreased subsea construction activity in the Gulf of Mexico, primarily attributable to delays in permitting of projects since the Gulf oil spill in April 2010 as well as the decreased amount of internal vessel utilization to develop our oil and gas properties in 2011. As previously noted our Q4000, Express and HP I vessels were involved in the Gulf oil spill response and containment efforts in the second and third quarters of 2010.

Oil and Gas revenues increased 73% during the nine-month period ended September 30, 2011, as compared to the same period in 2010, reflecting increased oil production and higher oil prices. Our production increased by 5.2 Bcfe for the nine-month period ended September 30, 2011, as compared to the same period in 2010. Our production for the nine-month period ended September 30, 2011 benefited from oil production from our Phoenix field that commenced production in October 2010, which was partially offset by decreased natural gas production from our Bushwood field.

Our Production Facilities revenues increased for the nine-month period ended September 30, 2011 reflecting full utilization of the HP I at the Phoenix field, which is owned 70% by us, in 2011, as compared to it being utilized by a third party in the Gulf oil spill response and containment efforts from June 2010 to October 2010. Our revenues also include the quarterly retainer fees related to the HFRS, which commenced April 1, 2011.

Gross Profit. For the nine-month period ended September 30, 2011, our Contracting Services gross profit decreased by 20% as compared to the same period last year primarily reflecting the weak subsea construction industry conditions in the Gulf of Mexico, which contributed significantly to our lower pipelay and robotics support vessel and ROV utilization rates. Our contracting services rates in 2010 benefitted from our increased scope of internal work related to our oil and gas properties as well as the Express being contracted to service the Gulf oil spill response and containment efforts.

The Oil and Gas gross profit increase of $317.8 million for the nine-month period ended September 30, 2011, as compared to the same period in 2010, was due primarily to increased oil production and higher oil price realizations. The increase in our production is primarily related to the commencement of production from our Phoenix field in October 2010. Our oil and gas gross profit was adversely affected by impairment charges totaling $25.1 million for the nine-month period ended September 30, 2011 and $171.9 million for the nine-month period ended September 30, 2010, including $159.9 million in the second quarter of 2010. See Note 4 for additional disclosure regarding our impairment charges covering the periods covered by this Quarterly Report on Form 10-Q.

The decrease in our Production Facilities gross profit in the nine-month period ended September 30, 2011, as compared to the same period in 2010, reflects full utilization of the HP I in 2011 at the Phoenix field, which is owned 70% by us, as opposed to four months of third party utilization at the Gulf oil spill response and containment efforts in the nine-month period ended September 30, 2010.

Gain on Sale or Purchase of Assets, Net. The gain for the nine-month period ended September 30, 2010 was primarily associated with the acquisition of the remaining 50% working interest related to the Camelot field in the United Kingdom (Note 4).

Selling, General and Administrative Expenses. Selling, general and administrative expenses of $70.8 million for the nine-month period ended September 30, 2011 were $20.9 million lower than the $91.7 million incurred in the same prior year period. The decrease primarily reflects the $17.5 million related to our settlement of litigation claims in Australia in 2010 (Note 14).

Equity in Earnings of Investments. Equity in earnings of investments increased by $3.5 million during the nine-month period ended September 30, 2011, as compared to the same prior year period. This increase was mostly due to the

Clough Helix JV having equity earnings of $1.4 million in 2011 associated with project work in China while in the 2010 period the joint venture incurred $5.0 million of losses related primarily to start-up costs (Note 6). Our equity in earnings also reflects lower throughput at Deepwater Gateway and Independence Hub reflecting lower production from the fields that are serviced by the respective facilities, including the disruptions caused by Tropical Storm Lee in early September 2011.

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Net Interest Expense. We reported net interest of $73.6 million for the nine-month period ended September 30, 2011, as compared to $61.6 million in the same prior year period. Gross interest expense of $76.0 million during the nine-month period ended September 30, 2011 was higher than the $74.7 million incurred in the same period in 2010 reflecting slightly higher interest rates. Capitalized interest totaled $0.8 million for the nine-month period ended September 30, 2011, as compared with $12.4 million for the same period last year. The decrease in our capitalized interest was primarily attributable to the completion of our major capital projects during the first half of 2010, including our Caesar and HP I vessels which were placed in service in the second quarter of 2010. Interest income totaled $1.6 million for the nine-month period ended September 30, 2011, as compared to $0.7 million for the nine-month period ended September 30, 2010, reflecting the increase in our cash balances.

Other Income (Expense). The $4.4 million variance in other expense for the nine-month period ended September 30, 2011 compared with the same prior year period primarily reflects foreign exchange fluctuations in our non U.S. dollar functional currencies and foreign exchange currency contracts. The strengthening of the U.S. dollar against other global currencies resulted in our recording foreign exchange losses totaling $5.2 million for the nine-month period ended September 30, 2011 as compared to losses of $0.6 million in the nine-month period ended September 30, 2010. We had $0.2 million of losses on our foreign exchange forward contracts for the nine-month period ended September 30, 2011 as compared $2.4 million for the nine-month period ended September 30, 2010 (Note 16). Other expense also includes the $2.4 million premium we paid to early extinguish the portion of the Senior Unsecured Notes we purchased in the third quarter of 2011 (Note 7).

Provision for Income Taxes. We had income tax expense of $49.2 million in the nine-month period ended September 30, 2011, as compared to income tax benefit of $42.0 million in the same prior year period. The variance primarily reflects increased profitability in the current year period. The effective tax rate for the nine-month period ending September 30, 2011 was 29.9%, as compared to a benefit rate of 35.8% for the nine-month period ending September 30, 2010 reflecting the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2011	December 31, 2010
	(in thousands)	
Net working capital	$ 432,106	$ 373,057
Long-term debt(1)	1,163,914	1,347,753
Liquidity(2)	932,708	787,296

(1) Long-term debt does not include the current maturities portion of the long-term debt as such amount is included in net working capital. It is also net of unamortized debt discount on our Convertible Senior Notes (Note 7).

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our revolving credit facility.

The carrying amount of our debt, including current maturities as of September 30, 2011 and December 31, 2010 follows:

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	September 30, 2011	December 31, 2010
	(in thousands)	
Term Loan (matures July 2015)(1)	$ 298,500	$ 410,441
Revolving Credit Facility (matures July 2015) (1)		
Convertible Senior Notes (matures March 2025) (2)	288,165	281,472
Senior Unsecured Notes (matures January 2016)	474,960	550,000
MARAD Debt (matures February 2027)	110,166	114,811
Loan Notes		1,208
Total	$ 1,171,791	$ 1,357,932

(1) Represents earliest date debt would mature; see Note 7 for conditions that would provide extension of maturity date.

(2) This amount is net of the unamortized debt discount of $11.8 million and $18.5 million, respectively. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012. Notes may be redeemed by the holders beginning in December 2012 (Note 7).

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

	Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 351,131	$ 241,766
Investing activities	$ (162,820)	$ (160,085)
Financing activities	$ (204,308)	$ (26,621)

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

We remain focused on maintaining a strong balance sheet and adequate liquidity. We may reduce planned capital spending and seek further additional dispositions of our non-core business assets (see "Executive Summary" above). We also have a reasonable basis for estimating our future cash flow supported by our remaining contracting services operations backlog and the significant hedged portion of our estimated oil and gas production through 2013. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility will be sufficient to fund our operations over the foreseeable future. We have no borrowings drawn on our Revolving Credit Facility as of September 30, 2011.

In accordance with our Credit Agreement, Senior Unsecured Notes, Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios (such as collateral coverage, interest coverage and consolidated leverage), and the maintenance of minimum net worth, working capital and debt-to-equity requirements. The Credit Agreement and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences (or at least 60% of the proceeds in certain dispositions of assets).

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Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans. As of September 30, 2011 and December 31, 2010, we were in compliance with all of our debt covenants and restrictions.

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

Our Convertible Senior Notes can be converted prior to stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying condensed consolidated balance sheet. No conversion triggers were met during the three-month and nine-month periods ended September 30, 2011. The holders may redeem the Convertible Senior Notes beginning December 2012 (Note 7 as well as Note 9 of our 2010 Form 10-K).

In June 2011, the Credit Agreement was amended to, among other things, to extend its maturity and increase the availability under our Revolving Credit Facility (Note 7). See Note 9 of our 2010 Form 10-K for additional information related to our long-term debt, including more information regarding other amendments of our Credit Agreement and our requirements and obligations under the debt agreements.

Working Capital

Cash flow from operating activities increased by $109.4 million in the nine-month period ended September 30, 2011 as compared to the same period in 2010. This increase primarily reflects the effect of increased oil production as well as the substantially higher oil prices.

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of dynamically positioned vessels, acquisition of select businesses, improvements to existing vessels, acquisition and development of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the nine-month period ended September 30, 2011 and 2010 were as follows:

	Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Capital expenditures:		
Contracting Services	$ (62,202)	$ (50,663)
Production Facilities(1)	(16,963)	(47,726)
Oil and Gas(1)	(88,684)	(64,523)
Investments in equity investments	(2,699)	(7,768)
Distributions from equity investments, net(2)	3,437	9,876
Sales of shares of Cal Dive common stock	3,588	
Proceeds from the sales of property		852
Decrease (increase) in restricted cash	703	(133)
Cash used in investing activities	$(162,820)	$ (160,085)

(1) Amounts for the nine-month period ended September 30, 2010 are net of insurance recoveries ($7.0 million for Production Facilities and $9.1 million for Oil and Gas). This insurance recovery is related to damages sustained to the Phoenix field in 2005 which we remediated upon our acquisition of the field in 2007.
(2) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments are detailed below.

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Financing Activities

The use of proceeds from our financing activities increased by $177.7 million for the nine-month period ended September 30, 2011 as compared to the same period in the prior year. The increase in financing activities reflects payments made to reduce our debt outstanding during the nine-month period ended September 30, 2011, including the $109.4 million payment on our Term Loan pursuant to the fourth amendment of our Credit Agreement and $77.4 million to early extinguish a portion of our Senior Unsecured Notes. See Note 7 herein for additional information regarding the debt repayments we made in 2011.

Restricted Cash

As of September 30, 2011 and December 31, 2010, we had $34.6 million and $35.3 million of restricted cash, all of which related to the funds contractually required to be escrowed to cover the asset retirement obligations associated with the South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

Equity Investments

Our investment in the Clough Helix JV (Note 6) totaled $9.4 million at September 30, 2011 and $4.9 million at December 31, 2010. Our investment in the Clough Helix JV is in the form of a loan, which is a fixed non-interest bearing with no stated maturity. We received the following distributions from our equity investments during the nine-month periods ended September 30, 2011 and 2010:

	Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Deepwater Gateway	$ 5,700	$ 6,125
Independence Hub	14,180	16,415
Total	$ 19,880	$ 22,540

Outlook

We anticipate capital expenditures for 2011 will total approximately $275 million (exclusive of expenditures related to our asset retirement obligations). Although we are in the preliminary stages of preparing our capital budget for 2012, we expect that a total of five of our subsea construction and well intervention vessels will be required to be sent to regulatory dry dock at some point during the year. The scope and cost of those projects is still being evaluated. We believe internally generated cash flow, cash from potential future sales of our non-core business assets, and borrowing availability under our existing credit facilities will provide the capital necessary to fund our current initiatives over the next twelve-month period.

The following table summarizes our contractual cash obligations as of September 30, 2011 and the scheduled years in which the obligations are contractually due:

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
Convertible Senior Notes(2)	$300,000	$	$	$	$300,000
Senior Unsecured Notes	474,960			474,960	
Term Loan (3)	298,500	3,000	6,000	289,500	
MARAD debt	110,166	4,877	10,496	11,569	83,224
Revolving Credit Facility(4)					
Interest related to long-term debt	436,107	77,600	152,168	98,873	107,466
Drilling and development costs	42,538	42,538			
Property and equipment	17,369	17,369			
Operating leases(5)	69,497	54,428	13,981	1,088	
Total cash obligations	$1,749,137	$199,812	$182,645	$875,990	$490,690

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(1) Excludes unsecured letters of credit outstanding at September 30, 2011 totaling $42.6 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2025 (Notes can be redeemed by us or we may be required to purchase them beginning in December 2012). Notes can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. Upon the occurrence of a triggering event, to the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At September 30, 2011, the conversion trigger was not met.

(3) Our Term Loan will mature no earlier than July 1, 2015 and may extend to July 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7).

(4) Our Revolving Credit Facility will mature no earlier than July 1, 2015 and may extend to January 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7).

(5) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2011 were approximately $61.4 million.

Contingencies

In March 2010, we reached an out of court settlement of a dispute associated with an offshore construction contract in Australia. Pursuant to the terms of this settlement we paid 15 million AUD to resolve all claims between us and the third party. Accordingly, our results for the nine-month period ended September 30, 2010 include approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. These amounts were recorded as selling, general and administrative expenses in the accompanying condensed consolidated statements of operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our 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. Please read the following discussion in conjunction with our "Critical Accounting Policies and Estimates" as disclosed in our 2010 Form 10-K.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

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Commodity Price Risk. As of September 30, 2011, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 4.5 MMBbl of oil and 8.1 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price	
Crude Oil:			(per barrel)	
October 2011 — December 2011	Swap	163.3 MBbl	82.62	
October 2011 — December 2011	Collar	35.3 MBbl	$ 95.00 — $124.59	
October 2011 — December 2011	Collar	50.0 MBbl	$100.00 — $122.80	a
January 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57	
January 2012 — December 2012	Collar	139.0 MBbl	$ 99.42 — $117.59	a
January 2012 — December 2012	Swap	16.0 MBbl	$103.20	a
January 2013 — December 2013	Swap	41.7 MBbl	$ 99.15	a
January 2013 — December 2013	Collar	41.7 MBbl	$ 95.00 — $102.60	a
Natural Gas:			(per Mcf)	
October 2011 — December 2011	Swap	703.3 Mmcf	$4.93	
January 2012 — December 2012	Swap	333.3 Mmcf	$4.70	
January 2012 — December 2012	Collar	166.7 Mmcf	$4.75 — $5.09	

a) The prices quoted in the table above are primarily NYMEX Henry Hub for natural gas or NYMEX West Texas Intermediate for crude oil. As footnoted above these costless collar contracts are priced as Brent crude oil.

All of commodity derivative contracts were designated as cash flow hedges and all remain effective and qualify for hedge accounting as of September 30, 2011 (Note 16).

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 September 30, 2011. 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 September 30, 2011 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.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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, our top 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 certain of the Company's executive officers. On August 17, 2011, a shareholder derivative lawsuit styled Scott Inglebritson v. Owen Kratz, et al was filed in the 61st Judicial District Court of Harris County, Texas, in which the plaintiff makes similar claims as those asserted in the action filed in federal court against the same defendants arising out of the same facts. In both cases, the plaintiff seeks monetary damages and injunctive relief on behalf of the Company. Both cases are in their preliminary stages. On September 28, 2011, the Company received a shareholder demand upon the Helix board of directors that the board take action with respect to certain of the Company's directors' and senior officers' breaches of fiduciary duties of candor, good faith, and loyalty, unjust enrichment, and aiding and abetting from 2010 to the present in connection with the awarding of allegedly excessive and unwarranted 2010 executive compensation. The board of directors is in the process of evaluating said demand.

See Part I, Item 1, Note 14 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum value of shares that may yet be purchased under the program (2)
July 1 to July 31, 2011(1)	257	$16.69		497,412
August 1 to August 31, 2011(1)				497,412
September 1 to September 30, 2011(1)	1,394	16.56		497,412
	1,651	$16.58		497,412

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

(2) Represents amounts of restricted shares issued to certain of our employees in 2011 (Note 11). Under the terms of our stock repurchase program, these grants increase the amount of shares available for repurchase. In

early October 2011, we repurchased all of the available 497,412 shares in open market transactions totaling $6.5 million for an average of $13.07 per share. For additional information regarding our stock repurchase program see Note 14 of the 2010 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: October 26, 2011	By: /s/ Owen Kratz
	Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: October 26, 2011	By: /s/ Anthony Tripodo
	Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
10.1	Amendment No. 4 to Credit Agreement, dated as of June 8, 2011, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer, and the lenders named thereto. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by registrant with Securities and Exchange Commission on June 8, 2011.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter(1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer(1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer(1)
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes – Oxley Act of 2002(2)
99.1	Report of Independent Registered Public Accounting Firm(1)
101.INS	XBRL Instance Document(2)
101.SCH	XBRL Schema Document(2)
101.CAL	XBRL Calculation Linkbase Document(2)
101.LAB	XBRL Label Linkbase Document(2)
101.PRE	XBRL Presentation Linkbase Document(2)
101.DEF	XBRL Definition Linkbase Document(2)

(1) Filed herewith
(2) Furnished herewith