HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
November 02, 2007

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

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2007

or

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

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 þ Accelerated filer o Non-accelerated filer o

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

Yes o No þ

As of October 31, 2007, 91,331,674 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, 2007 (Unaudited)	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 50,436	$ 206,264
Short-term investments		285,395
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $1,717 and $982, respectively	371,028	287,875
Unbilled revenue	36,697	82,834
Other current assets	155,052	61,532
Total current assets	613,213	923,900
Property and equipment	3,443,815	2,721,362
Less accumulated depreciation	(691,973)	(508,904)
	2,751,842	2,212,458
Other assets:		
Equity investments	212,975	213,362
Goodwill, net	835,073	822,556
Other assets, net	132,937	117,911
	$ 4,546,040	$ 4,290,187
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 261,569	$ 240,067
Accrued liabilities	269,289	199,650
Income tax payable	33,079	147,772
Current maturities of long-term debt	25,978	25,887
Total current liabilities	589,915	613,376
Long-term debt	1,444,649	1,454,469
Deferred income taxes	488,634	436,544
Decommissioning liabilities	149,602	138,905
Other long-term liabilities	6,770	6,143
Total liabilities	2,679,570	2,649,437

Commitments and contingencies		
Minority interest	80,091	59,802
Convertible preferred stock	55,000	55,000
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 91,319 and 90,628 shares issued, respectively	749,227	745,928
Retained earnings	949,134	752,784
Accumulated other comprehensive income	33,018	27,236
Total shareholders equity	1,731,379	1,525,948
	$ 4,546,040	$ 4,290,187

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,	
	2007	**2006**
Net revenues:		
Contracting services	$ 318,752	$ 229,392
Oil and gas	141,821	145,032
	460,573	374,424
Cost of sales:		
Contracting services	196,027	143,517
Oil and gas	98,228	100,437
	294,255	243,954
Gross profit	166,318	130,470
Gain on sale of assets, net	20,701	2,287
Selling and administrative expenses	42,146	30,309
Income from operations	144,873	102,448
Equity in earnings of investments	7,889	1,897
Net interest expense and other	13,467	15,103
Income before income taxes	139,295	89,242
Provision for income taxes	45,327	31,409
Minority interest	10,195	
Net income	83,773	57,833
Preferred stock dividends	945	804
Net income applicable to common shareholders	$ 82,828	$ 57,029
Earnings per common share:		
Basic	$ 0.92	$ 0.62
Diluted	$ 0.88	$ 0.60
Weighted average common shares outstanding:		
Basic	90,111	91,531

Diluted	95,649	96,918

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, 2007	Nine Months Ended September 30, 2006
Net revenues:		
Contracting services	$ 852,332	$ 664,630
Oil and gas	414,870	306,455
	1,267,202	971,085
Cost of sales:		
Contracting services	556,546	408,919
Oil and gas	266,958	197,738
	823,504	606,657
Gross profit	443,698	364,428
Gain on sale of assets, net	26,385	2,570
Selling and administrative expenses	106,134	78,751
Income from operations	363,949	288,247
Equity in earnings of investments, net of impairment charge	9,245	12,653
Net interest expense and other	40,765	20,543
Income before income taxes	332,429	280,357
Provision for income taxes	111,711	96,387
Minority interest	21,533	
Net income	199,185	183,970
Preferred stock dividends	2,835	2,413
Net income applicable to common shareholders	$ 196,350	$ 181,557
Earnings per common share:		
Basic	$ 2.18	$ 2.20
Diluted	$ 2.07	$ 2.09
Weighted average common shares outstanding:		
Basic	90,051	82,706

Diluted	96,087	88,209

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, 2007	Nine Months Ended September 30, 2006
Cash flows from operating activities:		
Net income	$ 199,185	$ 183,970
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	229,870	131,451
Asset impairment charge	904	
Dry hole expense	166	37,615
Equity in earnings of investments, net of distributions		(5,490)
Equity in losses of OTSL, inclusive of impairment charge	10,841	655
Amortization of deferred financing costs	2,315	1,582
Stock compensation expense	11,014	6,250
Deferred income taxes	48,159	64,561
Gain on sale of assets	(26,386)	(2,570)
Excess tax benefit from stock-based compensation	(28)	(7,842)
Minority interest	21,533	
Changes in operating assets and liabilities:		
Accounts receivable, net	(36,029)	(442)
Other current assets	(38,074)	5,361
Accounts payable and accrued liabilities	17,741	(25,105)
Income taxes payable	(115,556)	(24,970)
Other noncurrent, net	(45,127)	(23,440)
Net cash provided by operating activities	280,528	341,586
Cash flows from investing activities:		
Capital expenditures	(684,653)	(253,386)
Acquisition of businesses, net of cash acquired	(10,202)	(872,707)
Investments in equity investments	(16,132)	(23,092)
Distributions from equity investments, net of equity in earnings of investments	6,363	
Sale of short-term investments, net	285,395	
Increase in restricted cash	(834)	(21,404)
Proceeds from sales of property	4,343	31,827
Net cash used in investing activities	(415,720)	(1,138,762)
Cash flows from financing activities:		
Repayment of Senior Credit Facilities	(6,300)	835,000
Repayment of Cal Dive International, Inc. revolving credit facility	(84,000)	
Borrowings under revolving credit facilities	86,000	
Repayment of MARAD borrowings	(3,823)	(3,641)
Deferred financing costs	(231)	(11,143)

Capital lease payments	(1,882)	(2,184)
Preferred stock dividends paid	(2,835)	(2,668)
Repurchase of common stock	(9,821)	(266)
Excess tax benefit from stock-based compensation	28	7,842
Exercise of stock options, net	957	8,775
Net cash (used in) provided by financing activities	(21,907)	831,715
Effect of exchange rate changes on cash and cash equivalents	1,271	2,166
Net increase (decrease) in cash and cash equivalents	(155,828)	36,705
Cash and cash equivalents:		
Balance, beginning of year	206,264	91,080
Balance, end of period	$ 50,436	$ 127,785

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 Basis of Presentation

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 condensed consolidated financial statements are unaudited, 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 Annual Report on Form 10-K for the year ended December 31, 2006, as amended by our Form 10-K/A for the year ended December 31, 2006 filed on June 18, 2007 (2006 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. Operating results for the period ended September 30, 2007 are not necessarily indicative of the results that may be expected for the year ending December 31, 2007. Our balance sheet as of December 31, 2006 included herein has been derived from the audited balance sheet as of December 31, 2006 included in our 2006 Form 10-K. These condensed consolidated financial statements should be read in conjunction with the annual consolidated financial statements and notes thereto included in our 2006 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.

Note 2 Company Overview

We are an international offshore energy company that provides development solutions and other key services (contracting services operations) to the open market as well as to our own reservoirs (oil and gas operations). Our oil and gas business is a prospect generating, exploration, development and production company. By employing our own key services and methodologies in our reservoirs, we seek to lower finding and development costs relative to industry norms.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing the economics from marginal fields. Those life of field services are organized in five disciplines: reservoir and well tech services, drilling, production facilities, construction and well operations. We have disaggregated our contracting services operations into three reportable segments in accordance with Statement of Financial Accounting Standard No. 131 *Disclosures about Segments of an Enterprise and Related Information* (SFAS No. 131): Contracting Services (which currently includes services such as deepwater pipelay, well operations, robotics and reservoir and well tech services), Shelf Contracting, and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, the North Sea and the Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. Our Shelf Contracting segment, consists of our majority-owned subsidiary, Cal Dive International, Inc. (Cal Dive or CDI), including its 40% interest in Offshore Technology Solutions Limited (OTSL). For information related to the impairment of OTSL, see Note 9 Equity Investments. In December 2006, Cal Dive completed an initial public offering of 22,173,000 shares of its stock. See Note 4 Initial Public Offering of Cal Dive International, Inc. below.

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Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization and to achieve better returns than are likely to be generated through pure service contracting. Over the last 15 years we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed, and in July 2006 the properties of Remington Oil and Gas Corporation (Remington), an exploration, development and production company. 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.

Note 3 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. As of September 30, 2007 and December 31, 2006, we had $34.5 million and $33.7 million, respectively, of restricted cash included in other assets, net, all of which was related to funds required to be escrowed to cover decommissioning liabilities associated with the South Marsh Island 130 (SMI 130) acquisition in 2002 by our Oil and Gas segment. We have fully satisfied the escrow requirement as of September 30, 2007. We may use the restricted cash for decommissioning the related field.

The following table provides supplemental cash flow information for the nine months ended September 30, 2007 and 2006 (in thousands):

	Nine Months Ended September 30,	
	2007	**2006**
Interest paid (net of capitalized interest)	$ 43,096	$ 9,666
Income taxes paid	$179,107	$56,794

Non-cash investing activities for the nine months ended September 30, 2007 and 2006 included $25.8 million and $71.5 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 4 Initial Public Offering of Cal Dive International, Inc.

In December 2006, we contributed the assets of our Shelf Contracting segment into Cal Dive, our then wholly owned subsidiary. Cal Dive subsequently sold 22,173,000 shares of its common stock in an initial public offering and distributed the net proceeds of $264.4 million to us as a dividend. In connection with the offering, CDI also entered into a $250 million revolving credit facility. In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. For additional information related to the Cal Dive credit facility, see Note 10 Long-Term Debt below. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million, as a result of these transactions in 2006. CDI used the remaining proceeds for general corporate purposes.

In connection with the offering, together with CDI shares issued to CDI employees since the offering, our ownership of CDI decreased to approximately 73% as of September 30, 2007 and December 31, 2006. Subject to market conditions, we may sell additional shares of Cal Dive common stock in the future.

Further, in conjunction with the offering, the tax basis of certain of CDI s tangible and intangible assets was increased to fair value. The increased tax basis should result in additional tax deductions available to CDI over a period of two to five years. Under a Tax Matters Agreement between us and CDI, for a period of ten years from the closing of CDI s initial public offering, to the extent CDI generates taxable income sufficient to realize the additional tax deductions, CDI will be required to pay us 90% of the amount of tax savings actually realized from the step-up of the basis of certain assets. As of September 30, 2007 and December 31, 2006, we have a receivable from CDI of approximately $7.5 million and $11.3 million, respectively, related to the Tax Matters Agreement. For additional information related to the Tax Matters Agreement, see our 2006 Form 10-K.

Note 5 Acquisition of Remington Oil and Gas Corporation

On July 1, 2006, we acquired 100% of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrated in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash and stock and the assumption of $357.8 million of liabilities. The merger consideration was 0.436 shares of Helix common stock and $27.00 in cash for each share of Remington common stock. On July 1, 2006, we issued 13,032,528 shares of our common stock to Remington stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.6 million) through borrowings under a credit agreement (see Note 10 Long-Term Debt below).

The Remington acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The final valuation of net assets was completed in June 2007 with no material changes to our preliminary valuation. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 154,408
Property and equipment	863,935
Goodwill	711,656
Other intangible assets[1]	6,800
Total assets acquired	$ 1,736,799
Current liabilities	$ 131,881
Deferred income taxes	204,096
Decommissioning liabilities (including current portion)	20,044
Other non-current liabilities	1,800
Total liabilities assumed	$ 357,821
Net assets acquired	$ 1,378,978

(1) The intangible asset is related to a favorable drilling rig contract and to several non-compete agreements between the Company and

certain members of senior management. The fair value of the drilling rig contract was $5.0 million, with $5.0 million reclassified into property and equipment for drilling of certain successful exploratory wells in the nine months ended September 30, 2007. The fair value of the non-compete agreements was $1.8 million, which is being amortized over the term of the agreements (three years) on a straight-line basis.

Note 6 Oil and Gas Properties

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

As of September 30, 2007, we capitalized approximately $27.4 million of exploratory drilling costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged

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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 provides a detail of our capitalized exploratory project costs at September 30, 2007 and December 31, 2006 (in thousands):

	September 30, 2007	December 31, 2006
Noonan[(1)]	$	$ 27,824
Huey	11,556	11,378
Castleton (part of Gunnison)	7,075	7,070
South Marsh Island 123 #1	5,626	
Other	3,166	3,711
Total	$ 27,423	$ 49,983

(1) Wells have been completed.

As of September 30, 2007, all of these exploratory well costs had been capitalized for a period of one year or less, except for Huey and Castleton. We are not the operator of Castleton.

The following table reflects net changes in suspended exploratory well costs during the nine months ended September 30, 2007 (in thousands):

	2007
Beginning balance at January 1	$ 49,983
Additions pending the determination of proved reserves	210,780
Reclassifications to proved properties	(233,174)
Charged to dry hole expense	(166)
Ending balance at September 30	$ 27,423

Further, the following table details the components of exploration expense for the three and nine months ended September 30, 2007 and 2006 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Delay rental	$ 547	$ 509	$ 2,185	$ 799
Geological and geophysical costs	879	2,142	3,293	2,881
Dry hole expense	50	16,869	166	37,615
Total exploration expense	$ 1,476	$ 19,520	$ 5,644	$ 41,295

We agreed to participate in the drilling of an exploratory well (Tulane prospect) that was drilled in the first quarter of 2006. This prospect targeted reserves in deeper sands within the same trapping fault system of a currently producing well. In March 2006, mechanical difficulties were experienced in the drilling of this well, and after further review, the well was plugged and abandoned. Approximately $21.7 million related to this well was charged to earnings during the nine months ended September 30, 2006. Further, in the third quarter of 2006, we expensed approximately $15.9 million of exploratory drilling costs related to two deep shelf properties (acquired in the Remington acquisition which were in process prior to July 1, 2006) in which we determined commercial quantities of hydrocarbons were not discovered.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale.

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On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. (Sojitz), a wholly owned subsidiary of Sojitz Corporation, for a cash payment of $40 million and the proportionate recovery of all past and future capital expenditures related to the re-development of the fields, excluding the conversion of the *Helix Producer I*, which we plan to use as a redeployable floating production unit (FPU). Proceeds from the sale were collected in October 2007 ($51.2 million) and were included in other current assets at September 30, 2007. Sojitz will also pay its proportionate share of the operating costs including fees payable for the use of the FPU. A gain of approximately $18.8 million was recorded as of September 30, 2007 and the remaining gain was deferred due to potential contingencies in the sale agreement with Sojitz. In October 2007, we amended the agreement with Sojitz, which amendment eliminated these contingencies.

Note 7 Other Acquisitions

In October 2006, we acquired a 58% interest in Seatrac Pty Ltd. (Seatrac) for total consideration of approximately $12.7 million (including $180,000 of transaction costs), with approximately $9.1 million paid to existing Seatrac shareholders and $3.4 million for subscription of new Seatrac shares. We renamed this entity Well Ops SEA Pty Ltd. Seatrac is a subsea well intervention and engineering services company located in Perth, Australia. Under the terms of the purchase agreement, we had an option to purchase the remaining 42% of the entity for approximately $10.1 million. On July 1, 2007, we exercised this option and now own 100% of the entity. This purchase was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair value, with the excess being recorded as goodwill. The following table summarizes the preliminary estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash and cash equivalents	$ 2,631
Other current assets	4,279
Property and equipment	9,571
Goodwill	13,684
Total assets acquired	30,165
Accounts payable and accrued liabilities	(5,077)
Net assets acquired	$ 25,088

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to the identification and valuation of potential intangible assets and valuation of certain equipment. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. Any future change in the value of net assets will be offset by a corresponding increase or decrease in goodwill.

Note 8 Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
Other receivables	$ 4,571	$ 3,882
Prepaid insurance	25,167	17,320
Other prepaids	33,806	9,174
Current deferred tax assets	7,164	3,706
Insurance claims to be reimbursed	8,890	3,627

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	September 30, 2007	December 31, 2006
Hedging assets		5,202
Gas imbalance	7,045	4,739
Spare parts inventory	6,431	3,660
Current notes receivable		1,500
Other receivable (see Note 6)	51,217	
Other	10,761	8,722
	$ 155,052	$ 61,532

Other assets, net, consisted of the following as of September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
Restricted cash	$ 34,510	$ 33,676
Deferred drydock expenses, net	41,904	26,405
Deferred financing costs	26,678	28,257
Intangible assets with definite lives, net	14,276	20,783
Intangible asset with indefinite life	7,234	6,922
Other	8,335	1,868
	$ 132,937	$ 117,911

Accrued liabilities consisted of the following as of September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
Accrued payroll and related benefits	$ 41,405	$ 42,381
Royalties payable	80,599	67,822
Current decommissioning liability	29,869	28,766
Unearned revenue	31,179	13,223
Accrued interest	12,250	15,579
Deposit (see Note 6)	21,000	
Other	52,987	31,879
	$ 269,289	$ 199,650

Note 9 Equity Investments

As of September 30, 2007, we have the following material investments that are accounted for under the equity method of accounting:

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (Enterprise), formed Deepwater Gateway, L.L.C. (Deepwater Gateway) (each with a 50% interest) to design, construct, install, own and operate a tension leg platform (TLP) production hub primarily for Anadarko Petroleum Corporation s *Marco Polo* field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $113.6 million and $119.3 million as of September 30, 2007 and December 31, 2006, respectively, and was included in our Production Facilities segment.

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, LLC (Independence), an affiliate of Enterprise. Independence owns the Independence Hub platform located in Mississippi Canyon block 920 in a water depth of 8,000 feet. The platform reached mechanical completion in May 2007. As a result, our performance guaranty related to Independence terminated in May 2007 with no further obligations. First production began in July 2007. Our investment in Independence was $95.3 million and $82.7 million as of September 30, 2007 and December 31, 2006, respectively (including capitalized interest of $6.5 million and $5.5

million at September 30, 2007 and December 31, 2006, respectively), and was included in our Production Facilities segment.

OTSL. In July 2005, we acquired a 40% minority interest in OTSL, now held through CDI, in exchange for our dynamically positioned dive support vessel, the *Witch Queen*. OTSL provides marine construction services to the oil and gas industry in and around Trinidad and Tobago. During the second quarter 2007, CDI determined that there was an other than temporary impairment in OTSL at June 30, 2007 and the full value of CDI s investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $11.8 million in the second quarter of 2007.

Note 10 Long-Term Debt

Senior Credit Facilities

On July 3, 2006, we entered into a Credit Agreement (the Credit Agreement) with Bank of America, N.A., as administrative agent and as lender, together with the other lenders (collectively, the Lenders). Under the Credit Agreement, we borrowed $835 million in a term loan (the Term Loan) and may borrow up to $300 million (the Revolving Loans) under a revolving credit facility (the Revolving Credit Facility). In addition, the Revolving Credit Facility may be used for issuances of letters of credit up to an aggregate outstanding amount of $50 million. The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition. At September 30, 2007 and December 31, 2006, $826.6 million and $832.9 million, respectively, of the Term Loan was outstanding.

The Term Loan matures on July 1, 2013 and is subject to scheduled principal payments of $2.1 million quarterly. The Revolving Loans mature on July 1, 2011. We may elect to prepay amounts outstanding under the Term Loan without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. We had $86 million outstanding under the Revolving Loans at September 30, 2007. The Credit Agreement includes terms, conditions and covenants that we consider customary for this type of facility. As of September 30, 2007, we were in compliance with these terms, conditions and covenants.

The Term Loan currently bears interest at the one-, three- or six-month LIBOR at our election plus a 2.00% margin. Our average interest rate on the Term Loan for the three and nine months ended September 30, 2007 was approximately 7.4% and 7.3%, respectively, including the effects of our interest rate swaps (see below). The Revolving Loans bear interest based on one-, three- or six-month LIBOR at our election plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement.

As the rates for the Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we entered into various interest rate swaps with various financial institutions in an aggregate amount equal to $200 million of notional value effective as of October 3, 2006. The objective of the hedges is to eliminate the variability of cash flows in the interest payments for up to $200 million of our Term Loan. Changes in the cash flows of the interest rate swap are expected to exactly offset the changes in cash flows (i.e., changes in interest rate payments) attributable to fluctuations in LIBOR on up to $200 million of our Term Loan. These hedges are designated as cash flow hedges and qualify for hedge accounting. Under the swaps we receive interest based on three-month LIBOR and pay interest quarterly at an average annual fixed rate of 5.131% which began in October 2006.

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Cal Dive International, Inc. Revolving Credit Facility

In November 2006, CDI entered into a five-year $250 million revolving credit facility with certain financial institutions. The loans mature in November 2011. Loans under this facility are non-recourse to Helix. Loans under the revolving credit facility currently bear interest at the LIBOR rate plus a margin ranging from 0.625% to 1.75%. CDI s interest rate on the credit facility for the three and nine months ended September 30, 2007 was approximately 6.1%.

The CDI credit agreement and the other documents entered into in connection with this credit facility include terms, conditions and covenants that are customary for this type of facility. At September 30, 2007, CDI was in compliance with these terms, conditions and covenants.

At September 30, 2007 and December 31, 2006, CDI had outstanding debt of $117 million and $201 million, respectively, under this credit facility. CDI expects to use the remaining availability under the revolving credit facility for working capital and other general corporate purposes. We do not have access to any unused portion of CDI s revolving credit facility.

Convertible Senior Notes

On March 30, 2005, we issued $300 million of our 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 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 balance sheet. During the third quarter of 2007, no conversion triggers were met.

Approximately 1.2 million shares and 1.7 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three and nine months ended September 30, 2007, respectively, and approximately 1.2 million shares and 1.3 million shares were included in such calculation for the three and nine months ended September 30, 2006, respectively, because our average share price for the respective periods was above the conversion price of approximately $32.14 per share. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued on conversion. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770.

MARAD Debt

At September 30, 2007 and December 31, 2006, $127.5 million and $131.3 million was outstanding on our long-term financing for construction of the *Q4000.* This U.S. government guaranteed financing (MARAD Debt) is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration. The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the *Q4000,* with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 30, 2007, we were in compliance with these covenants and restrictions.

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In September 2005, we entered into an interest rate swap agreement with a bank. The swap was designated as a cash flow hedge of a forecasted transaction in anticipation of the refinancing of the MARAD Debt from floating-rate debt to fixed-rate debt that closed on September 30, 2005. The interest rate swap agreement totaled an aggregate notional amount of $134.9 million with a fixed interest rate of 4.695%. On September 30, 2005, we terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain was deferred and is being amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Other

In connection with the acquisition of Helix Energy Limited, we issued a two-year note payable to the former owners totaling approximately £3.1 million, or approximately $5.6 million, on November 3, 2005 (the balance was approximately $6.4 million and $6.2 million at September 30, 2007 and at December 31, 2006, respectively). The note bears interest at a LIBOR based floating rate with interest payments due quarterly beginning January 1, 2006. The note is due on November 5, 2007.

Deferred financing costs of $26.7 million and $28.3 million are included in other assets, net as of September 30, 2007 and December 31, 2006, respectively, and are being amortized over the life of the respective loan agreements.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of September 30, 2007 were as follows (in thousands):

	Term Loan	Revolving Loans	CDI Revolving Credit Facility	Convertible Senior Notes	MARAD Debt	Loan Notes[(1)]	Capital Leases	Total
Less than one year	$ 8,400	$	$	$	$ 4,014	$ 11,422	$ 2,142	$ 25,978
One to two years	8,400				4,214			12,614
Two to three years	8,400				4,424			12,824
Three to four years	8,400	86,000			4,645			99,045
Four to five years	8,400		117,000		4,877			130,277
Over five years	784,600			300,000	105,289			1,189,889
Long-term debt	826,600	86,000	117,000	300,000	127,463	11,422	2,142	1,470,627
Current maturities	(8,400)				(4,014)	(11,422)	(2,142)	(25,978)
Long-term debt, less current maturities	$ 818,200	$ 86,000	$ 117,000	$ 300,000	$ 123,449	$	$	$ 1,444,649

(1) Includes $5 million of loan amounts

provided by Kommandor RØMØ, a member in Kommandor LLC of which we own 50%, to Kommandor LLC as of September 30, 2007. The loan is expected to be repaid at the completion of the initial conversion, which is forecasted to be in the first quarter of 2008. As such, the entire loan amount is classified as current.

We had unsecured letters of credit outstanding at September 30, 2007 totaling approximately $34.9 million. These letters of credit primarily guarantee various contract bidding, contractual performance and insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three and nine months ended September 30, 2007 and 2006 (in thousands):

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Interest expense	$ 24,010	$ 20,352	$ 70,257	$ 29,950
Interest income	(1,107)	(2,602)	(7,682)	(4,065)
Capitalized interest	(8,935)	(2,603)	(20,734)	(5,014)
Interest expense, net	$ 13,968	$ 15,147	$ 41,841	$ 20,871

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The carrying amount and estimated fair value of our debt instruments, including current maturities as of September 30, 2007 and December 31, 2006 were as follows (amount in thousands):

	September 30, 2007		December 31, 2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan(1)	$826,600	$810,068	$832,900	$834,462
Revolving Credit Facility(2)	86,000	86,000		
Cal Dive Revolving Credit Facility(2)	117,000	117,000	201,000	201,000
Convertible Senior Notes(1)	300,000	451,800	300,000	378,780
MARAD Debt(3)	127,463	121,256	131,286	126,691
Loan Notes(4)	11,422	11,422	11,146	11,146

(1) The fair values of these instruments were based on quoted market prices as of September 30, 2007 and December 31, 2006, as applicable.

(2) The carrying values of these revolving credit facilities approximate fair value as of September 30, 2007 and December 31, 2006.

(3) The fair value of the MARAD debt was determined by a third-party valuation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government-guaranteed obligations in the marketplace with similar terms.

(4) The carrying value of the loan notes approximates fair value as the maturity dates of these loans are less than one year.

Note 11 Income Taxes

The effective tax rate for the three and nine months ended September 30, 2007 was 33% and 34%, respectively. The effective tax rate for the three and nine months ended September 30, 2006 was 35% and 34%, respectively. The effective tax rate for the third quarter of 2007 decreased as a result of the benefit derived from the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production and the effect of lower tax rates in certain foreign jurisdictions. The effective tax rate for the nine months ended September 30, 2007 was impacted by non-cash equity losses and the related impairment charge in connection with CDI s investment in OTSL for which minimal tax benefit was recorded and a $2.0 million nondeductible accrual by CDI for a cash settlement to be paid for a civil claim by the Department of Justice related to the consent decree CDI entered into in connection with the Acergy US Inc. (Acergy) and Torch Offshore, Inc. (Torch) acquisitions in 2005. This increase was partially offset by lower effective tax rates in foreign jurisdictions.

We adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48) on January 1, 2007. The impact of the adoption of FIN 48 was immaterial on our financial position, results of operations and cash flows. We record tax related interest in interest expense and tax penalties in operating expenses as allowed under FIN 48. As of September 30, 2007, we had no material unrecognized tax benefits and no material interest or penalties were recognized.

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2002, 2003, 2004, 2005 and 2006 remain subject to examination by the U.S. Internal Revenue Service (IRS). In addition, as we acquired Remington on July 1, 2006, we are exposed to any tax uncertainties related to Remington. For Remington, the tax periods ending December 31, 2003, 2004, 2005, and June 30, 2006, remain subject to examination by the IRS. The 2004 and 2005 tax returns for Remington are currently under examination by the IRS. The 2004 tax return includes the utilization of a net operating loss generated prior to 1999. As of September 30, 2007, the IRS has not issued any proposed adjustments for the years under examination.

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Note 12 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 include the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign currency exchange rate exposure, as well as non-derivative forward sale contracts to reduce commodity price risk on future sales of hydrocarbons. All derivatives are reflected in our balance sheet at fair value unless otherwise noted.

Commodity Hedges

We have entered into various cash flow hedging costless collar contracts to stabilize cash flows relating to a portion of our expected oil and gas production. All of these qualify for hedge accounting. The aggregate fair value of the hedge instruments was a net (liability) asset of $(1.5) million and $5.2 million as of September 30, 2007 and December 31, 2006, respectively. We recorded unrealized losses of approximately $782,000 and $4.4 million, net of tax benefit of $421,000 and $2.4 million, respectively, during the three and nine months ended September 30, 2007, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective. For the three and nine months ended September 30, 2006, we recorded $8.6 million and $11.0 million, respectively, of unrealized gains, net of tax expense of $4.6 million and $5.9 million, respectively. During the three and nine months ended September 30, 2007, we reclassified approximately $3.2 and $5.5 million of gains, respectively, from other comprehensive income to net revenues upon the sale of the related oil and gas production. For the three and nine months ended September 30, 2006, we reclassified approximately $614,000 and $6.9 million, respectively, of gains from other comprehensive income to net revenues.

As of September 30, 2007, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 840 MBbl of oil and 11,250 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
October 2007 - December 2007	Collar	100 MBbl	$50.00 $68.28
January 2008 - December 2008	Collar	45 MBbl	$56.57 $76.51
October 2007 - December 2009	Forward Sale(1)	90 MBbl	$71.90
Natural Gas:			
October 2007 - December 2007	Collar	1,200,000 MMBtu	$7.50 $10.37
January 2008 - December 2008	Collar	637,500 MMBtu	$7.32 $10.87
October 2007 - December 2009	Forward Sale(1)	1,240,096 MMBtu	$8.26

(1) We have not entered into any natural gas or oil forward sales contracts subsequent to September 30, 2007. Hedge accounting does not apply to these contracts as these contracts qualify as normal

purchases and
sales
transactions.

We have not entered into any hedge instruments subsequent to September 30, 2007. Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

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Interest Rate Hedge

As the rates for our Term Loan are subject to market influences and will vary over the term of the loan, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of the interest payments for our Term Loan. The interest rate swaps were effective October 3, 2006. These interest rate swaps qualify for hedge accounting. See -Note 10 - Long-Term Debt above for a detailed discussion of our Term Loan. The aggregate fair value of the hedge instruments was a net liability of $2.1 million and $531,000 as of September 30, 2007 and December 31, 2006, respectively. For the three and nine months ended September 30, 2007, we recorded unrealized losses of approximately $1.8 million and $859,000, respectively, net of tax expense of $749,000 and $563,000, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective.

Foreign Currency Hedge

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. In December 2006, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we hedged 11.0 million at an exchange rate of 1.3326 to be settled in December 2007. In August 2007, we entered into a 14.0 million foreign currency forward contract at an exchange rate of 1.3595 to be settled in May 2008. The aggregate fair value of the hedge instruments that were still outstanding as of such date was a net asset (liability) of $2.1 million and $(184,000) as of September 30, 2007 and December 31, 2006, respectively. For the three and nine months ended September 30, 2007, we recorded unrealized gains of approximately $829,000 and $1.4 million, respectively, net of tax expense of $525,000 and $791,000, respectively, in accumulated other comprehensive income, a component of shareholders equity.

Note 13 Comprehensive Income

The components of total comprehensive income for the three and nine months ended September 30, 2007 and 2006 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Net income	$ 83,773	$ 57,833	$ 199,185	$ 183,970
Foreign currency translation gain	4,775	1,273	9,491	10,279
Unrealized gain (loss) on hedges, net	(1,618)	8,552	(3,709)	10,994
Total comprehensive income	$ 86,930	$ 67,658	$ 204,967	$ 205,243

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

	September 30, 2007	December 31, 2006
Cumulative foreign currency translation adjustment	$ 34,071	$ 24,580
Unrealized gain (loss) on hedges, net	(1,053)	2,656
Accumulated other comprehensive income	$ 33,018	$ 27,236

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Note 14 Earnings Per Share

Basic earnings per share (EPS) 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 computation of basic and diluted EPS amounts for the three and nine months ended September 30, 2007 and 2006 were as follows (in thousands):

		Three Months Ended September 30, 2007		Three Months Ended September 30, 2006	
		Income	Shares	Income	Shares
Earnings applicable per common share	Basic	$ 82,828	90,111	$ 57,029	91,531
Effect of dilutive securities:					
Stock options			368		386
Restricted shares			293		150
Employee stock purchase plan			2		4
Convertible Senior Notes			1,244		1,217
Convertible preferred stock		945	3,631	804	3,630
Earnings applicable per common share	Diluted	$ 83,773	95,649	$ 57,833	96,918

		Nine Months Ended September 30, 2007		Nine Months Ended September 30, 2006	
		Income	Shares	Income	Shares
Earnings applicable per common share	Basic	$ 196,350	90,051	$ 181,557	82,706
Effect of dilutive securities:					
Stock options			386		445
Restricted shares			292		132
Employee stock purchase plan			4		12
Convertible Senior Notes			1,723		1,284
Convertible preferred stock		2,835	3,631	2,413	3,630
Earnings applicable per common share	Diluted	$ 199,185	96,087	$ 183,970	88,209

There were no antidilutive stock options in the three and nine months ended September 30, 2007 and 2006 as the option strike price was below the average market price for the applicable periods. Net income for the diluted EPS calculation for the three and nine months ended September 30, 2007 and 2006 was adjusted to add back the preferred stock dividends as if the convertible preferred stock were converted into 3.6 million shares of common stock.

Note 15 Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the 1995 Incentive Plan), the 2005 Long-Term Incentive Plan, as amended (the 2005 Incentive Plan) and the 1998 Employee Stock Purchase Plan, as amended (the ESPP). In addition, CDI has a stock-based compensation plan, the 2006 Long-Term Incentive Plan (the CDI Incentive Plan) and an Employee Stock Purchase Plan (the CDI ESPP) available only to the employees of CDI and its subsidiaries.

We began accounting for our stock-based compensation plans under the fair value method beginning January 1, 2006. We continue to use the Black-Scholes option pricing model for valuing stock options and recognize compensation cost for our share-based payments on a straight-line basis over the applicable vesting period. During the nine months ended September 30, 2007, we granted 687,907 shares of restricted shares to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 Incentive Plan.

The average market value of the restricted shares was $31.56 per share, or $21.7 million, at the date of grant. As a result of the increase in the number of restricted stock recipients, for 2007 restricted share grants to executives and selected management employees at the grant date we estimated that 8% may be forfeited. No forfeitures were estimated for outstanding unvested options and restricted shares granted prior to January 1, 2007 as historical forfeitures have been immaterial. There were no stock option grants in the nine months ended September 30, 2007 and 2006.

For the three and nine months ended September 30, 2007, $259,000 and $789,000, respectively, was recognized as compensation expense related to stock options. Future compensation cost associated with unvested options at September 30, 2007 was approximately $1.0 million. The weighted average vesting period related to unvested stock options at September 30, 2007 was approximately one year. For the three and nine months ended September 30, 2007, $2.8 million and $8.7 million, respectively, was recognized as compensation expense related to restricted shares (of which $536,000 and $1.6 million, respectively, of expense was related to the CDI Incentive Plan). For the three and nine months ended September 30, 2006, $1.6 million and $4.1 million, respectively, was recognized as compensation expense related to restricted shares. Future compensation cost associated with unvested restricted shares at September 30, 2007 was approximately $36.8 million, of which $7.2 million is related to the CDI Incentive Plan. The weighted average vesting period related to unvested restricted shares of our common stock at September 30, 2007 was approximately 3.8 years.

Employee Stock Purchase Plan

Effective May 12, 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six-month period. The purchase price is equal to 85% of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to the lesser of 10% of an employee s base salary or $25,000 of our stock value. In January and July 2007, we issued 109,754 and 113,230 shares, respectively, of our common stock to our employees under the ESPP, which increased the number of shares of our outstanding common stock. We subsequently repurchased approximately the same number of shares of our common stock in the open market at $29.94 and $40.00 per share in January and July 2007, respectively, and reduced the number of shares of our outstanding common stock. During the three and nine months ended September 30, 2006, 97,598 and 79,878 shares of common stock were purchased in the open market at a share price of $33.12 and $23.11, respectively. For the three and nine months ended September 30, 2007, we recognized $553,000 and $1.5 million, respectively, of compensation expense related to stock purchased under the ESPP and the CDI ESPP (of which $300,000 of expense was related to the CDI ESPP that became effective third quarter 2007). For the three and nine months ended September 30, 2006, we recognized $490,000 and $1.1 million of compensation expense related to stock purchased under the ESPP.

Note 16 Business Segment Information (in thousands)

Our operations are conducted through two lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Production Facilities, and Oil and Gas. The Contracting Services segment includes services such as deepwater pipelay, well operations, robotics and reservoir and well tech services. The Shelf Contracting segment consists of assets deployed primarily for diving-related activities and shallow water construction. See Note 4 Initial Public Offering of Cal Dive International, Inc. for a discussion of the initial public offering of CDI common stock. All material intercompany transactions among the segments have been eliminated in our consolidated results of operations.

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. The majority of our Production Facilities segment is accounted for under the equity method of accounting. Our investment in Kommandor LLC, a Delaware limited liability company, was consolidated in accordance with FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN 46) and is included in our Production Facilities segment.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Revenues -				
Contracting Services	$ 192,331	$ 122,842	$ 484,767	$ 336,464
Shelf Contracting	176,928	128,364	461,412	372,918
Oil and Gas	141,821	145,032	414,870	306,455
Intercompany elimination	(50,507)	(21,814)	(93,847)	(44,752)
Total	$ 460,573	$ 374,424	$ 1,267,202	$ 971,085
Income from operations -				
Contracting Services	$ 43,697	$ 24,763	$ 98,779	$ 63,956
Shelf Contracting	56,993	48,082	141,438	143,999
Production Facilities equity investments(1)	(182)	(250)	(514)	(903)
Oil and Gas	51,443	35,860	139,345	88,200
Intercompany elimination	(7,078)	(6,007)	(15,099)	(7,005)
Total	$ 144,873	$ 102,448	$ 363,949	$ 288,247
Equity in losses of OTSL, inclusive of impairment	$	$ (3,237)	$ (10,841)	$ (587)
Equity in earnings of equity investments excluding OTSL	$ 7,889	$ 5,134	$ 20,086	$ 13,240

(1) Included selling and administrative expense of Production Facilities incurred by us. See equity in earnings of equity investments excluding OTSL for earnings contribution.

	September 30, 2007	December 31, 2006
Identifiable Assets -		
Contracting Services	$ 1,114,737	$ 1,313,206

Shelf Contracting	486,252	452,153
Production Facilities	319,069	242,113
Oil and Gas	2,625,982	2,282,715
Total	$ 4,546,040	$ 4,290,187

Intercompany segment revenues during the three and nine months ended September 30, 2007 and 2006 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Contracting Services	$ 31,487	$ 12,581	$ 62,984	$ 30,773
Shelf Contracting	19,020	9,233	30,863	13,979
Total	$ 50,507	$ 21,814	$ 93,847	$ 44,752

Intercompany segment profits (which related primarily to intercompany capital projects) during the three and nine months ended September 30, 2007 and 2006 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Contracting Services	$ 865	$ 1,909	$ 3,540	$ 2,157
Shelf Contracting	6,213	4,098	11,559	4,848
Total	$ 7,078	$ 6,007	$ 15,099	$ 7,005

During the three and nine months ended September 30, 2007, we derived $74.2 million and $171.5 million, respectively, of our revenues from our operations in the United Kingdom, utilizing $290.4

million of our total assets in this region. During the three and nine months ended September 30, 2006, we derived $50.9 million and $113.2 million, respectively, of our revenues from our operations in the United Kingdom, utilizing $208.1 million of our total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

Note 17 Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corporation (Kerr-McGee). Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or OKCD) in exchange for a revenue interest that is an overriding royalty interest of 25% of our 20% working interest. The investors of OKCD include certain current and former members of Helix senior management. Production began in December 2003. Payments to OKCD from us totaled $5.2 million and $16.9 million in the three and nine months ended September 30, 2007, respectively, and $8.8 million and $28.2 million in the three and nine months ended September 30, 2006.

Note 18 Commitments and Contingencies

Commitments

We are converting the *Caesar* (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to be approximately $135 million, of which approximately $68.2 million had been incurred, with an additional $41.8 million committed, at September 30, 2007. In addition, we will upgrade the *Q4000* to include drilling capability by adding a modular-based drilling system, and will also perform thruster modifications and other significant upgrades on the vessel. The total cost for all of these activities is estimated to be approximately $110.0 million, of which approximately $53.5 million had been incurred, with an additional $29.8 million committed, at September 30, 2007.

We are also constructing a $183 million multi-service dynamically positioned dive support/well intervention vessel (*Well Enhancer*) that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. We expect the *Well Enhancer* to join our fleet in 2008. At September 30, 2007, we had incurred approximately $56.8 million, with an additional $85.5 million committed to this project.

Further, we, along with Kommandor RØMØ, a Danish corporation, formed a joint venture called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the *Helix Producer I* (the Vessel). Our share of the cost of the ferry and the conversion is approximately $60 million which will be funded through equity contributions and project financing. Helix has agreed to provide all interim construction financing to the joint venture on terms that would equal an arms length financing transaction. Total borrowings will be approximately $45 million, and will be repaid with the proceeds of the permanent financing facility described below. Upon completion of the conversion, scheduled for early 2008, we will charter the Vessel from Kommandor LLC, and will install, at 100% our cost, processing facilities and a disconnectable fluid transfer system (DTS) on the Vessel for use on our Phoenix field. The cost of these additional facilities is approximately $110 million. Kommandor LLC qualified as a variable interest entity under FIN 46. We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of September 30, 2007 in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

On June 19, 2007, Kommandor LLC entered into a term loan agreement (Loan Agreement) with Nordea Bank Norge ASA. Pursuant to the Loan Agreement, the lenders will make available to Kommandor up to $45.0 million pursuant to a secured term loan facility. Kommandor will use all amounts borrowed under the facility to repay its existing subordinated indebtedness for the long-term financing of the Vessel and to fund expenses and fees related to the conversion of such Vessel to operate as a floating production unit. Kommandor expects this borrowing to occur in the first quarter of 2008 upon the delivery of the Vessel after its conversion, and at such time, in accordance with the provisions of FIN 46, the entire obligation will be included in our consolidated balance sheet. The funding of the amount set forth in the draw request is subject to certain customary conditions.

Our projected capital expenditures on certain projects have increased as compared to the initially budgeted amounts due primarily to the weakening of the U.S. dollar with respect to foreign denominated contracts, scope changes and escalating costs for certain materials and services due to increasing demand. In addition, as of September 30, 2007, we have also committed approximately $28.6 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Contingencies

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.

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service (MMS) that the price thresholds for both oil and gas were exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 (DWRRA), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. Our only leases affected by this order are the Gunnison leases. On May 2, 2006, the MMS issued an order that superseded and replaced the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both MMS orders. Other operators in the deepwater Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases such as ours. We do not anticipate that the MMS director will issue decisions in our or the other companies administrative appeals until the Kerr-McGee litigation has been resolved in a final decision. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government could appeal the decision. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed from the Gunnison leases), plus interest at 5%, for our portion of the *Gunnison* related MMS claim. The total reserved amount at September 30, 2007 and December 31, 2006 was approximately $51.8 million and $42.6 million, respectively. At this time, it is not anticipated that any penalties would be assessed if we are unsuccessful in our appeal.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular reporting period, we believe that the outcome of all such matters and proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Note 19 Recently Issued Accounting Principles

In September 2006, the FASB issued Statement of Financial Accounting Standard No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with U.S. generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

Note 20 Pending Transaction

On June 11, 2007, CDI and Horizon Offshore, Inc. (Horizon) announced that they had entered into an agreement under which CDI will acquire Horizon in a transaction valued at approximately $650.0 million, including approximately $22.0 million of Horizon s net debt as of March 31, 2007. Under the terms of the agreement, Horizon stockholders will receive a combination of 0.625 shares of CDI common stock and $9.25 in cash for each share of Horizon common stock outstanding, or an estimated total of 20.4 million CDI shares and $302.5 million in cash. The boards of directors of CDI and Horizon unanimously approved the transaction. Closing of the transaction is subject to regulatory approvals and other customary conditions, as well as Horizon stockholder approval, and is expected to occur in the fourth quarter of 2007. In limited circumstances, if Horizon fails to close the transaction, it must pay CDI a termination fee of $18.9 million. The cash portion of the transaction will be funded through a $675.0 million commitment from a bank, consisting of a $375.0 million senior secured term loan and a $300.0 million senior secured revolving credit facility, each of which is non-recourse to Helix. On September 28, 2007, CDI and Horizon each received a request for additional information from the Antitrust Division of the U.S. Department of Justice. The request was issued under the notification requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and has the effect of extending the waiting period for a period of 30 calendar days from the date of the parties substantial compliance with the request. Both parties intend to continue to work cooperatively to respond to the request and obtain termination of the waiting period as soon as practicable.

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 certain statements that are, or may be deemed to be, forward-looking statements within the meaning of 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, other than statements of historical facts, included herein or incorporated herein by reference are forward-looking statements. Included among forward-looking statements are, among other things:

- statements related to the volatility in commodity prices for oil and gas and in the supply of and demand for oil and gas or the ability to replace oil and gas reserves;

- 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 property or well;

- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;

- statements relating to the construction or acquisition of vessels or equipment and our proposed acquisition of any producing property or well prospect, including statements concerning the engagement of any engineering, procurement and construction contractor and any anticipated costs related thereto;

- statements that our proposed vessels, when completed, will have certain characteristics or the effectiveness of such characteristics;

- statements regarding projections of revenues, gross margin, expenses, earnings or losses or other financial items;

statements regarding our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which are subject to change;

statements regarding any SEC or other governmental or regulatory inquiry or investigation;

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statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;

statements regarding anticipated developments, industry trends, performance or industry ranking relating to our services or any statements related to the underlying assumptions related to any projection or forward-looking statement;

statements related to environmental risks, drilling and operating risks, or exploration and development risks and any statements related to the ability of the company to retain key members of its senior management and key employees;

statements regarding general economic or political conditions, whether internationally, nationally or in the regional and local market areas in which we are doing business; and

any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, estimate, expect, forecast, plan, project, propose, strategy, predict, envision, continue, may, potential, achieve, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those described under the heading Risk Factors in our 2006 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.

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. There have been no material changes or developments in authoritative accounting pronouncements or in our evaluation of the accounting estimates and the underlying assumptions or methodologies that we believe would change the Critical Accounting Policies and Estimates as disclosed in our 2006 Form 10-K.

Recently Issued Accounting Principles

In September 2006, the FASB issued SFAS No. 157. This statement defines fair value, establishes a framework for measuring fair value in accordance with U.S. generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

In February 2007, the FASB issued SFAS No. 159, which allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

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Proposed Accounting Principle

In August 2007, the FASB proposed FASB Staff Position (FSP) APB 14-a, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)*. The proposed FSP would require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The proposed change in accounting treatment would be effective for fiscal years beginning after December 15, 2007, and applied retrospectively to prior periods. If adopted, this FSP would change the accounting treatment for our Convertible Senior Notes. This new accounting treatment could impact our results of operations and result in an increase to non-cash interest expense beginning in 2008 for financial statements covering past and future periods. We are currently evaluating the potential impact of this issue on our consolidated financial statements in the event that this pronouncement is adopted by the FASB.

RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services operations and oil and gas operations.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing the economics from marginal fields. Those life of field services are organized in five disciplines: reservoir and well tech services, drilling, production facilities, construction and well operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services (which currently includes services such as deepwater pipelay, well operations, robotics and reservoir and well tech services), Shelf Contracting, and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, the North Sea and the Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. The Shelf Contracting segment consists of assets deployed primarily for diving-related activities and shallow water construction. See Note 4 Initial Public Offering of Cal Dive International, Inc. for a discussion of the initial public offering of CDI common stock (which falls within the Shelf Contracting segment).

Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization and to achieve better returns than are likely to be generated through pure service contracting. Over the last 15 years we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed, and in July 2006 the properties of Remington Oil and Gas Corporation (Remington), an exploration, development and production company. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

Comparison of Three Months Ended September 30, 2007 and 2006

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

	Three Months Ended September 30, 2007	2006	Increase/ (Decrease)
Revenues (in thousands) -			
Contracting Services	$ 192,331	$ 122,842	$ 69,489
Shelf Contracting	176,928	128,364	48,564
Oil and Gas	141,821	145,032	(3,211)
Intercompany elimination	(50,507)	(21,814)	(28,693)
	$ 460,573	$ 374,424	$ 86,149
Gross profit (in thousands) -			
Contracting Services	$ 59,864	$ 34,144	$ 25,720
Shelf Contracting	69,939	57,738	12,201
Oil and Gas	43,593	44,595	(1,002)
Intercompany elimination	(7,078)	(6,007)	(1,071)
	$ 166,318	$ 130,470	$ 35,848
Gross Margin -			
Contracting Services	31%	28%	3 pts
Shelf Contracting	40%	45%	(5) pts
Oil and Gas	31%	31%	pts
Total company	36%	35%	1 pt
Number of vessels[(1)]/ Utilization[(2)] -			
Contracting Services:			
Pipelay	2/97%	3/66%	
Well operations	2/83%	2/86%	
ROVs	44/86%	32/85%	
Shelf Contracting	25/74%	25/83%	

(1) Represents number of vessels as of the end 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 months ended September 30, 2007 and 2006 were as follows (in thousands):

	Three Months Ended September 30,		**Increase/**
	2007	**2006**	**(Decrease)**
Contracting Services	$ 31,487	$ 12,581	$ 18,906
Shelf Contracting	19,020	9,233	9,787
	$ 50,507	$ 21,814	$ 28,693

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Intercompany segment profit (which related primarily to intercompany capital projects) during the three months ended September 30, 2007 and 2006 was as follows (in thousands):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Increase/ (Decrease)
Contracting Services	$ 865	$ 1,909	$ (1,044)
Shelf Contracting	6,213	4,098	2,115
	$ 7,078	$ 6,007	$ 1,071

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented (price volume analysis relates to U.S. operations only):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Increase/ (Decrease)
Oil and Gas information-			
Oil production volume (MBbls)	853	1,185	(332)
Oil sales revenue (in thousands)	$ 61,137	$ 74,147	$ (13,010)
Average oil sales price per Bbl (excluding hedges)	$ 74.38	$ 63.56	$ 10.82
Average realized oil price per Bbl (including hedges)	$ 71.63	$ 62.55	$ 9.08
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 10,761		
Change in production volume (in thousands)	(23,771)		
Total increase in oil sales revenue (in thousands)	$ (13,010)		
Gas production volume (MMcf)	10,508	9,447	1,061
Gas sales revenue (in thousands)	$ 73,958	$ 69,941	$ 4,017
Average gas sales price per mcf (excluding hedges)	$ 6.51	$ 7.21	$ (0.70)
Average realized gas price per mcf (including hedges)	$ 7.04	$ 7.40	$ (0.36)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (3,450)		
Change in production volume (in thousands)	7,467		
Total increase in gas sales revenue (in thousands)	$ 4,017		
Total production (MMcfe)	15,629	16,560	(931)
Price per Mcfe	$ 8.64	$ 8.70	$ (0.06)
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 135,095	$ 144,088	$ (8,993)
Miscellaneous revenues[(1)]	6,726	944	5,782
	$ 141,821	$ 145,032	$ (3,211)

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment (U.S. operations only) 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 (in thousands) converted to Mcfe at a ratio of one barrel of oil to six Mcf:

	Three Months Ended September 30,			
	2007		2006	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses[1]:				
Direct operating expenses[2]	$ 25,803	$ 1.65	$ 22,851	$ 1.38
Repairs and maintenance	5,184	0.33	9,188	0.55
Other[3]	11,638	0.74	240	0.01
Total	$ 42,625	$ 2.72	$ 32,279	$ 1.94
Depletion expense	$ 50,747	$ 3.25	$ 46,301	$ 2.80
Accretion expense	$ 2,733	$ 0.17	$ 2,409	$ 0.15

(1) Excludes exploration expense of $1.5 million and $19.5 million for the three months ended September 30, 2007 and 2006, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Includes plug and abandonment overruns in 2007 related to hurricanes *Katrina* and *Rita* totaling $12.5 million, partially offset by $865,000 of insurance recoveries.

Results of operations for our Oil and Gas segment in the United Kingdom were immaterial for the three months ended September 30, 2007 and 2006.

Revenues. During the three months ended September 30, 2007, our revenues increased by 23% as compared to the same period in 2006. Contracting Services revenues increased primarily due to the following:

improved contract pricing for the pipelay, well operations and remotely operated vehicle (ROV) divisions due to continually improving market conditions; and

significantly increased revenues related to our ROV division for ROV support work and trenching projects in third quarter 2007.

Shelf Contracting revenues increased primarily as a result of the initial deployment of certain assets we acquired through the Acergy, Torch and Fraser Diving International Limited (Fraser) acquisitions that came into service subsequent to first quarter 2006. These increases were partially offset by a decrease in revenues from four point and utility vessels due to lower utilization.

Oil and Gas revenues decreased 2% during the three months ended September 30, 2007 as compared to the same period in 2006. The decrease was primarily due to weather-related delays. The increase in gas revenues was attributable to higher gas production, partially offset by lower gas prices realized in the third quarter of 2007 as compared to the same prior year period.

Gross Profit. Gross profit in the third quarter of 2007 increased 27% as compared to the same period in 2006. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the pipelay, well operations and ROV divisions. The gross profit increase in third quarter 2007 as compared to the same prior year period for Shelf Contracting was due to the initial deployment of certain assets we acquired through the Acergy and Fraser Diving acquisitions subsequent to the second quarter of 2006. Shelf Contracting gross margin decrease in third quarter 2007 as compared to third quarter 2006 was due to certain lower margin contracts in the international markets and increased depreciation and amortization related to deferred drydock costs on newly deployed vessels and other vessel upgrades.

The Oil and Gas gross profit decrease of $1.0 million in third quarter 2007 as compared to the same period in 2006 was primarily due to lower oil production and a decrease in gas prices, as discussed above. Further, in the third quarter of 2007, the Oil and Gas segment incurred approximately $12.5 million of plug and abandonment overruns related to hurricanes *Katrina* and *Rita*, partially offset by insurance recoveries of $865,000. In third quarter 2006, we incurred exploration expense of $19.5 million which included dry hole cost of approximately $15.9 million related to two deep shelf properties (acquired in the Remington acquisition) in which we determined commercial quantities of hydrocarbons were not discovered.

Gain on Sale of Assets, Net. Gain on sale of assets, net, increased by $18.4 million during the three months ended September 30, 2007 as compared to the same prior year period. This increase was primarily related to a gain of $18.8 million for the sale of a working interest to Sojitz. On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz for a cash payment of $40 million. The remaining gain was deferred due to potential contingencies in the sales agreement with Sojitz. In October 2007, we amended the agreement with Sojitz, which amendment eliminated these contingencies. We expect to record the remaining gain of $21 million in the fourth quarter 2007.

Selling and Administrative Expenses. Selling and administrative expenses of $42.1 million for the third quarter of 2007 were $11.8 million higher than the $30.3 million incurred in the same prior year period. The increase was due primarily to higher overhead to support our growth and increased incentive compensation accruals. Selling and administrative expenses increased slightly to 9% of revenues in the three months ended September 30, 2007 as compared to 8% in the same prior year period.

Equity in Earnings of Investments. Equity in earnings of investments increased by $6.0 million during the three months ended September 30, 2007 as compared to the same prior year period. This increase was partially due to a $2.6 million increase in equity in earnings related to our 20% investment in Independence Hub which began production during the third quarter. The remaining increase was attributable to our investment in Deepwater Gateway. Included in the third quarter 2006 earnings was an equity loss of $3.2 million from CDI s 40% minority ownership interest in OTSL. As of June 30, 2007, the carrying value of CDI s investment in OTSL was reduced to zero as a result of a non-cash asset impairment charge.

Net Interest Expense and Other. We reported net interest and other expense of $13.5 million in third quarter 2007 as compared to $15.1 million in the prior year. Gross interest expense of $24.0 million during the three months ended September 30, 2007 was higher than the $20.4 million incurred in 2006 as a result of our Term Loan and Revolving Loans, which closed in July 2006, and CDI s revolving credit facility, which closed in December 2006. Offsetting the increase in interest expense was $8.9 million of capitalized interest and $1.1 million of interest income in the third quarter of 2007, compared with $2.6 million of capitalized interest and $2.6 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $45.3 million in the third quarter of 2007 as compared to $31.4 million in the same prior year period. The increase was primarily due to increased profitability. The effective tax rate of 33% for third quarter 2007 was lower than the 35% for third quarter 2006. The effective tax rate for the third quarter of 2007 decreased as a result of the benefit derived from the Internal Revenue Code section 199 manufacturing deduction primarily related to oil and gas properties and the effect of lower tax rates in foreign jurisdictions.

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Comparison of Nine Months Ended September 30, 2007 and 2006

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

	Nine Months Ended September 30, 2007	2006	Increase/ (Decrease)
Revenues (in thousands) -			
Contracting Services	$ 484,767	$ 336,464	$ 148,303
Shelf Contracting	461,412	372,918	88,494
Oil and Gas	414,870	306,455	108,415
Intercompany elimination	(93,847)	(44,752)	(49,095)
	$ 1,267,202	$ 971,085	$ 296,117
Gross profit (in thousands) -			
Contracting Services	$ 137,429	$ 93,829	$ 43,600
Shelf Contracting	173,456	168,887	4,569
Oil and Gas	147,912	108,717	39,195
Intercompany elimination	(15,099)	(7,005)	(8,094)
	$ 443,698	$ 364,428	$ 79,270
Gross Margin -			
Contracting Services	28%	28%	pts
Shelf Contracting	38%	45%	(7) pts
Oil and Gas	36%	35%	1 pt
Total company	35%	38%	(3) pts
Number of vessels(1)/ Utilization(2) -			
Contracting Services:			
Pipelay	2/87%	3/84%	
Well operations	2/81%	2/80%	
ROVs	44/81%	32/81%	
Shelf Contracting	25/69%	25/84%	

(1) Represents number of vessels as of the end 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 months ended September 30, 2007 and 2006 were as follows (in thousands):

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Increase/ (Decrease)
Contracting Services	$ 62,984	$ 30,773	$ 32,211
Shelf Contracting	30,863	13,979	16,884
	$ 93,847	$ 44,752	$ 49,095

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Intercompany segment profit (which related primarily to intercompany capital projects) during the nine months ended September 30, 2007 and 2006 was as follows (in thousands):

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Increase/ (Decrease)
Contracting Services	$ 3,540	$ 2,157	$ 1,383
Shelf Contracting	11,559	4,848	6,711
	$ 15,099	$ 7,005	$ 8,094

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented (price volume analysis relates to U.S. operations only):

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Increase/ (Decrease)
Oil and Gas information-			
Oil production volume (MBbls)	2,750	2,382	368
Oil sales revenue (in thousands)	$ 173,619	$ 148,426	$ 25,193
Average oil sales price per Bbl (excluding hedges)	$ 64.06	$ 63.27	$ 0.79
Average realized oil price per Bbl (including hedges)	$ 63.13	$ 62.31	$ 0.82
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 1,953		
Change in production volume (in thousands)	23,240		
Total increase in oil sales revenue (in thousands)	$ 25,193		
Gas production volume (MMcf)	30,499	19,200	11,299
Gas sales revenue (in thousands)	$ 231,126	$ 155,246	$ 75,880
Average gas sales price per mcf (excluding hedges)	$ 7.32	$ 7.61	$ (0.29)
Average realized gas price per mcf (including hedges)	$ 7.58	$ 8.09	$ (0.51)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (9,749)		
Change in production volume (in thousands)	85,629		
Total increase in gas sales revenue (in thousands)	$ 75,880		
Total production (MMcfe)	47,000	33,492	13,508
Price per Mcfe	$ 8.61	$ 9.07	$ (0.46)
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 405,381	$ 303,672	$ 101,709
Miscellaneous revenues(1)	9,489	2,783	6,706
	$ 414,870	$ 306,455	$ 108,415

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment (U.S. operations only) 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 (in thousands) converted to Mcfe at a ratio of one barrel of oil to six Mcf:

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	Nine Months Ended September 30, 2007		2006	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 70,712	$ 1.50	$ 44,362	$ 1.32
Repairs and maintenance	15,875	0.34	22,999	0.69
Impairment expense	904	0.02		
Other(3)	15,717	0.33	712	0.02
Total	$ 103,208	$ 2.19	$ 68,073	$ 2.03
Depletion expense	$ 146,186	$ 3.11	$ 82,296	$ 2.46
Accretion expense	$ 7,827	$ 0.17	$ 6,145	$ 0.18

(1) Excludes exploration expense of $5.6 million and $41.3 million for the nine months ended September 30, 2007 and 2006, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Includes plug and abandonment overruns in 2007 related to hurricanes *Katrina* and *Rita* totaling $18.5 million, partially offset by $2.8 million of insurance

recoveries.

Results of operations for our Oil and Gas segment in the United Kingdom were immaterial for the nine months ended September 30, 2007 and 2006.

Revenues. During the nine months ended September 30, 2007, our revenues increased by 30% as compared to the same period in 2006. Contracting Services revenues increased primarily due to improved contract pricing for the pipelay, well operations and ROV divisions. Shelf Contracting revenues increased primarily as a result of the initial deployment of certain assets we acquired through the Torch, Acergy and Fraser acquisitions that came into service subsequent to the first quarter of 2006. These increases were partially offset by two vessels CDI did not operate (one owned and one chartered) in the first nine months of 2007 that were in operation in 2006 and an increased number of out-of-service days for regulatory drydock and vessel upgrades for certain vessels in our Shelf Contracting segment.

Oil and Gas revenues increased 35% during the nine months ended September 30, 2007 as compared to the same period in 2006. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 40% during the nine months ended September 30, 2007 over the same period in 2006 was mainly attributable to properties acquired in connection with the Remington acquisition, which was effective July 1, 2006. The Oil and Gas revenue increase was partially offset by lower gas prices realized in the first nine months of 2007 as compared to the same prior year period.

Gross Profit. Gross profit in the first nine months of 2007 increased 22% as compared to the same period in 2006. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the pipelay, well operations and ROV divisions. The gross profit decrease within Shelf Contracting was primarily attributable to overall lower margins in the international markets, an increased number of out-of-service days as a result of planned drydocks, and increased depreciation and amortization related to deferred drydock costs on newly deployed vessels and other vessel upgrades.

The Oil and Gas gross profit increase in the first nine months of 2007 as compared to the same period in 2006 was primarily due to higher oil and gas production as discussed above. In addition, gross profit and gross margin were higher in the nine months ended September 30, 2007 as compared to 2006 as a result of a decrease in exploration costs from $41.3 million in 2006 to $5.6 million in 2007. Further, we incurred $18.5 million of plug and abandonment overruns related to hurricanes *Katrina* and *Rita*, partially offset by insurance recoveries of $2.8 million in the first nine months of 2007. In the same period of 2006, we incurred inspection and repair costs of $14.9 million attributable to the hurricanes, partially offset by $4.3 million in insurance recoveries. Exploration costs were higher in the first nine months of 2006 primarily as a result of the $37.6 million in dry hole expense related to the Tulane prospect in first

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quarter 2006 ($21.7 million) and two deep shelf properties dry holes (acquired in the Remington acquisition) in third quarter 2006 ($15.9 million). The gross profit increase was partially offset by lower gas prices as discussed above and higher depletion expense in the first nine months of 2007 related to assets acquired in connection with the Remington acquisition.

Gain on Sale of Assets, Net. Gain on sale of assets, net, increased by $23.8 million during the nine months ended September 30, 2007 as compared to the same prior year period. On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz for a cash payment of $40 million and recognized a gain of $18.8 million. The remaining gain was deferred due to potential contingencies in the agreement. In October 2007, we amended the sales agreement with Sojitz, which amendment eliminated these contingencies. We expect to record the remaining gain of $21 million in fourth quarter 2007. We also recognized the following gains in the first nine months of 2007:

Sale of mobile offshore production unit	$2.4 million
Sale of 50% interest in Camelot	$1.6 million
Sale of a saturation system owned by CDI	$1.6 million

Selling and Administrative Expenses. Selling and administrative expenses of $106.1 million for the first nine months of 2007 were $27.3 million higher than the $78.8 million incurred in the same prior year period. The increase was due primarily to higher overhead to support our growth and increased incentive compensation accruals. Further, in June 2007, CDI recorded a $2.0 million charge for an anticipated cash settlement referred to above with the Department of Justice. For both nine-month periods ended September 30, 2007 and 2006, selling and administrative expenses were approximately 8% of revenues.

Equity in Earnings of Investments, Net of Impairment Charge. Equity in earnings of investments decreased by $3.4 million during the nine months ended September 30, 2007 as compared to the same prior year period. This decrease was primarily due to second quarter 2007 equity losses from CDI s 40% investment in OTSL and a related non-cash asset impairment charge together totaling $11.8 million. This decrease was partially offset by a $5.3 million increase in equity in earnings related to our 20% investment in Independence Hub as we reached mechanical completion in March 2007 and began receiving demand fees and tariffs as production began in the third quarter. In addition, equity in earnings of our 50% investment in Deepwater Gateway increased by $1.8 million in the first nine months of 2007 as compared to 2006 due to higher throughput at the *Marco Polo* TLP.

Net Interest Expense and Other. We reported net interest and other expense of $40.8 million in the nine months ended September 30, 2007 as compared to $20.5 million in the prior year. Gross interest expense of $70.3 million during the nine months ended September 30, 2007 was higher than the $30.0 million incurred in 2006 as a result of our Term Loan and Revolving Loans, which closed in July 2006, and CDI s revolving credit facility, which closed in December 2006. Offsetting the increase in interest expense was $20.7 million of capitalized interest and $7.7 million of interest income in the first nine months of 2007, compared with $5.0 million of capitalized interest and $4.1 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $111.7 million in the nine months ended September 30, 2007 as compared to $96.4 million in the same prior year period. The effective tax rate for the nine months ended September 30, 2007 and 2006 was 34%. The effective tax rate for the nine months ended September 30, 2007 was impacted by the non-cash equity losses and the related impairment charge in connection with CDI s investment in OTSL for which minimal tax benefit was recorded and a $2.0 million nondeductible accrual by CDI for a cash settlement to be paid for a civil claim by the Department of Justice related to the consent decree CDI entered into in connection with the Acergy and Torch acquisitions in 2005. This increase was partially offset by positive impact of Internal Revenue Code section 199 manufacturing deductions and lower effective tax rates in 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 (in thousands):

	September 30, 2007	December 31, 2006
Net working capital	$ 23,298	$ 310,524
Long-term debt[1]	1,444,649	1,454,469

(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.

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Net cash provided by (used in):		
Operating activities	$ 280,528	$ 341,586
Investing activities	$ (415,720)	$ (1,138,762)
Financing activities	$ (21,907)	$ 831,715

Our primary cash needs are to fund capital expenditures to allow the growth of our current lines of business and to repay outstanding borrowings and make related interest payments. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

In accordance with the Senior Credit Facilities, Convertible Senior Notes, MARAD Debt and Cal Dive s credit facility, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 30, 2007 and December 31, 2006, we were in compliance with these covenants and restrictions. The Senior Credit Facilities 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 Senior Credit Facilities do, however, permit us to incur unsecured indebtedness, and also permit our domestic subsidiaries to incur project financing indebtedness (such as our MARAD Debt) secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

The Convertible Senior Notes can be converted prior to the 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 balance sheet. During the third quarter of 2007, no conversion triggers were met.

For the remainder of 2007, assuming the current balance of the CDI revolving credit facility remains outstanding, we expect to make approximately $21.2 million of interest payments, excluding the effect of interest rate swaps. In addition, we expect to make preferred dividend payments totaling approximately $950,000 for the remainder of 2007. As of September 30, 2007, we had $182 million of available borrowing capacity under our credit facilities, and CDI had $133 million of available borrowing under its revolving credit facility. We do not have access to any unused portion of CDI s revolving credit facility. See Notes to Condensed Consolidated Financial Statements (Unaudited) Note 10 Long-term Debt for additional information related to our long-term obligations, including our obligations under capital commitments.

Working Capital

Cash flow from operating activities decreased by $61.1 million in the nine months ended September 30, 2007 as compared to the same period in 2006. This decrease was primarily due to net income taxes paid in the first nine months of 2007 of approximately $179.1 million, most of which ($126.6 million) was related to the proceeds received from the CDI initial public offering. In addition, during the first nine months of 2007, we performed approximately $32.8 million of drydock work on our vessels in both our Contracting Services and Shelf Contracting segments. These decreases were partially offset by increases in payables and accruals due primarily to our growth, partially offset by increases in trade accounts receivable also due to significantly higher revenues and by higher profitability, after adjusting for non-cash related costs such as depreciation, deferred taxes, stock compensation expense, equity in losses and impairment of OTSL and minority interest reduction, in the nine months ended September 30, 2007 as compared to the same period in 2006.

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 of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the nine months ended September 30, 2007 and 2006 were as follows (in thousands):

	Nine Months Ended September 30,	
	2007	**2006**
Capital expenditures:		
Contracting Services	$ (182,674)	$ (68,684)
Shelf Contracting	(26,390)	(21,055)
Production Facilities	(68,471)	(340)
Oil and Gas[(1)]	(407,118)	(163,307)
Acquisition of businesses, net of cash acquired:		
Remington Oil and Gas Corporation[(2)]	(136)	(772,047)
Seatrac[(3)]	(10,066)	
Acergy US Inc.		(78,174)
Fraser		(22,486)
Sale of short-term investments	285,395	
Investments in production facilities	(16,132)	(23,092)
Distributions from equity investments, net[(4)]	6,363	
Increase in restricted cash	(834)	(21,404)
Proceeds from sale of properties	4,343	31,827
Cash provided by (used in) investing activities	$ (415,720)	$ (1,138,762)

(1) Included approximately $166,000 and $36.7 million of capital expenditures related to exploratory dry holes in the nine

months ended September 30, 2007 and 2006. For additional information, see Notes to Condensed Consolidated Financial Statements (Unaudited) Note 6.

(2) For additional information related to the Remington acquisition, see Notes to Condensed Consolidated Financial Statements (Unaudited) Note 5.

(3) For additional information related to the Seatrac acquisition, see Notes to Condensed Consolidated Financial Statements (Unaudited) Note 7.

(4) Distributions from equity investments are net of undistributed equity earnings from our equity investments, exclusive of OTSL. Gross distributions from our equity

investments are
detailed below.

On June 11, 2007, CDI and Horizon Offshore, Inc. (Horizon) announced that they had entered into an agreement under which CDI will acquire Horizon in a transaction valued at approximately $650.0 million, including approximately $22.0 million of Horizon s net debt as of March 31, 2007. Under the terms of the agreement, Horizon stockholders will receive a combination of 0.625 shares of CDI common stock and $9.25 in cash for each share of Horizon common stock outstanding, or an estimated total of 20.4 million CDI shares and $302.5 million in cash. The boards of directors of CDI and Horizon unanimously approved the transaction. Closing of the transaction is subject to regulatory approvals and other customary conditions, as well as Horizon stockholder approval, and is expected to occur in the fourth quarter of 2007. In limited circumstances, if Horizon fails to close the transaction, it must pay CDI a termination fee of $18.9 million. The cash portion of the transaction will be funded through a $675.0 million commitment from a bank, consisting of a $375.0 million senior secured term loan and a $300.0 million senior secured revolving credit facility, each of which will non-recourse to Helix. On September 28, 2007, CDI and Horizon each received a request for additional information from the Antitrust Division of the U.S. Department of Justice. The request was issued under the notification requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and has the effect of extending the waiting period for a period of 30 calendar days from the date of the parties substantial compliance with the request. Both parties intend to continue to work cooperatively to respond to the request and obtain termination of the waiting period as soon as practicable.

Short-term Investments

As of September 30, 2007, we did not hold any short-term investments. As of December 31, 2006, we held approximately $285.4 million, respectively, in municipal auction rate securities which have been classified as available-for-sale securities. These instruments were long-term variable rate bonds tied to short-term interest rates that are reset through a Dutch Auction process which occurs every 7 to 35 days. Although these instruments did not meet the definition of cash and cash equivalents, due to the liquid nature of these securities, we used these instruments to fund our working capital as needed.

Restricted Cash

As of September 30, 2007 and December 31, 2006, we had $34.5 million and $33.7 million, respectively, of restricted cash included in other assets, net, in the accompanying condensed consolidated balance sheet, all of which related to the funds required to be escrowed to cover decommissioning liabilities associated with the SMI 130 acquisition in 2002 by our Oil and Gas segment. We have fully satisfied the escrow requirement as of September 30, 2007. We may use the restricted cash for decommissioning the related field.

Equity Investments

We made the following contributions to our equity investments during the nine months ended September 30, 2007 and 2006 (in thousands):

	Nine Months Ended September 30,	
	2007	**2006**
Independence	$ 12,475	$ 23,092
Other	3,656	
Total	$ 16,131	$ 23,092

We received the following distributions from our equity investments during the nine months ended September 30, 2007 and 2006 (in thousands):

	Nine Months Ended September 30,	
	2007	**2006**
Deepwater Gateway	$ 20,500	$ 7,750
Independence	6,000	
OTSL		68
Total	$ 26,500	$ 7,818

During the second quarter of 2007, CDI determined that there was an other than temporary impairment in OTSL at June 30, 2007 and the full value of its investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $11.8 million in the second quarter of 2007.

Oil and Gas Activities

In February 2007, we completed the drilling of an exploratory well in our 100% owned Noonan prospect located in Garden Banks block 506 in the Gulf of Mexico. The Noonan well has been completed and the development plan being screened includes a fast track subsea tie-back to the 100% owned East Cameron block 381 platform located in shallower water. First production is expected to be achieved in the second half of 2008.

In July 2007, we announced that we completed the drilling of an exploratory well in our 100% owned Danny prospect also located in Garden Banks block 506. The well confirmed the presence of high quality oil in a single sand body. The well has been completed and is anticipated that the Danny discovery will be developed in conjunction with the development of the Noonan reservoir. First production from Danny is expected in early 2009. As of September 30, 2007, approximately $156.9 million of capitalized project costs were related to Noonan and Danny.

On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz for a cash payment of $40 million and the proportionate recovery of all past and future capital expenditures related to the re-development of the fields, excluding the conversion of the *Helix Producer I*, which we plan to use as a redeployable floating production unit (FPU). Proceeds from the sale were collected in October 2007 ($51.2 million) and were included in other current assets at September 30, 2007. Sojitz will also pay its proportionate share of the operating costs including fees payable for the use of the FPU. A gain of approximately $18.8 million was recorded as of September 30, 2007 and the remaining gain was deferred due to potential contingencies in the sales agreement with Sojitz. In October 2007, we amended the agreement with Sojitz, which amendment eliminated these contingencies. We expect to record the remaining gain of $21 million in the fourth quarter 2007.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale.

Outlook

We anticipate capital expenditures for the remainder of 2007 will range from $365 million to $415 million. Our projected capital expenditures on certain projects have increased as compared to the initially budgeted amounts due primarily to the weakening of the U.S. dollar with respect to foreign denominated contracts, scope changes and escalating costs for certain materials and services due to increasing demand. We may increase or decrease these plans based on various economic factors. We believe internally generated cash flow and borrowings under our existing credit facilities will provide the necessary capital to fund our 2007 initiatives (excluding the pending Horizon acquisition).

The following table summarizes our contractual cash obligations as of September 30, 2007 and the scheduled years in which the obligations are contractually due (in thousands):

	Total[1]	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes[2]	$ 300,000	$	$	$	$ 300,000
Term Loan	826,600	8,400	16,800	16,800	784,600
MARAD debt	127,463	4,014	8,638	9,522	105,289
Revolving Credit Facility	86,000			86,000	
CDI Revolving Credit Facility	117,000			117,000	
Loan notes	11,422	11,422			
Capital leases	2,142	2,142			
Acquisition of businesses[3]	302,500	302,500			
Drilling and development costs	28,600	28,600			
Property and equipment[4]	226,259	226,259			
Operating leases[5]	140,722	67,270	59,511	6,091	7,850
Other[6]	4,815	4,100	715		
Total cash obligations	$ 2,173,523	$ 654,707	$ 85,664	$ 235,413	$ 1,197,739

(1) Excludes unsecured letters of credit outstanding at September 30, 2007 totaling $34.9 million. These letters of credit primarily guarantee various contract bidding, contractual performance and insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated maturity (see Notes to Condensed

Consolidated Financial Statements (Unaudited) Note 10). If in future quarters the conversion price trigger is met and we do not have long-term financing or commitments available to cover the conversion (or a portion thereof), the portion uncovered would be classified as a current liability in the accompanying balance sheet.

(3) Related to the cash portion of CDI s pending Horizon acquisition. CDI has obtained a commitment for long-term financing to fund the cash portion of the acquisition. See Notes to Condensed Consolidated Financial Statements (Unaudited) Note 20 included herein for detailed discussion of this transaction.

(4)

Costs incurred as of September 30, 2007 and additional property and equipment commitments at September 30, 2007 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Project Cost
Caesar conversion	$ 68,213	$ 41,787	$ 135,000
Q4000 upgrade & modification	53,511	29,812	110,000
Well Enhancer construction	56,820	85,445	183,000
Helix Producer I conversion[a]	69,590	69,215	210,000
Total	$ 248,134	$ 226,259	$ 638,000

(a) Represents 100% of the vessel conversion cost, of which we expect our portion to be approximately $170.0 million.

(5) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2007 were approximately $114.2 million.

(6) Consisted of scheduled payments pursuant to 3-D seismic license

agreements.

Contingencies

In orders from the MMS dated December 2005 and May 2006, we received notice from the MMS that the price thresholds were exceeded for 2004 oil and gas production and for 2003 gas production, and that royalties are due on such production notwithstanding the provisions of the DWRRA. As of September 30, 2007, we have approximately $51.8 million accrued for the related royalties and interest. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government could appeal the decision. See Notes to Condensed Consolidated Financial Statements (Unaudited) Note 18 for a detailed discussion of this contingency.

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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.

Interest Rate Risk. As of September 30, 2007, including the effects of interest rate swaps, approximately 57% of our outstanding debt was based on floating rates. As a result, we are subject to interest rate risk. In September 2006, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. Excluding the portion of our debt for which we have interest rate swaps in place, the interest rate applicable to our remaining variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $2.6 million and $7.7 million in interest expense for the three and nine months ended September 30, 2007, respectively. Interest rate risk was immaterial in the three and nine months ended September 30, 2006 as an immaterial portion of our outstanding debt at such date was based on floating rates.

Commodity Price Risk. As of September 30, 2007, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 840 MBbl of oil and 11,250 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price	
Crude Oil:				
October 2007 - December 2007	Collar	100 MBbl	$50.00	$68.28
January 2008 - December 2008	Collar	45 MBbl	$56.57	$76.51
October 2007 - December 2009	Forward Sale(1)	90 MBbl	$71.90	
Natural Gas:				
October 2007 - December 2007	Collar	1,200,000 MMBtu	$7.50	$10.37
January 2008 - December 2008	Collar	637,500 MMBtu	$7.32	$10.87
October 2007 - December 2009	Forward Sale(1)	1,240,096 MMBtu	$8.26	

(1) We have not entered into any natural gas or oil forward sales contracts subsequent to September 30, 2007. Hedge accounting does not apply to these contracts as these contracts qualify as normal purchases and sales transactions.

We have not entered into any hedge instruments subsequent to September 30, 2007. Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

Foreign Currency Exchange Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. In December 2006, we entered into various foreign currency forward contracts to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we hedged 11.0 million at an exchange rate of 1.3326 to be settled in December 2007. In August 2007, we entered into a 14.0 million foreign currency forward contract at an exchange rate of 1.3595 to be settled in May 2008. The aggregate fair value of the hedge instruments was a net asset (liability) of $2.1 million and $(184,000) as of September 30, 2007 and December 31, 2006, respectively. For the three and nine months ended September 30, 2007, we recorded unrealized gains of approximately $829,000 and $1.4 million, respectively, net of tax expense of $525,000 and $791,000, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective.

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Item 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures*. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended September 30, 2007. 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, 2007 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

See Part I, Item 1, Note 18 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
July 1 to July 31, 2007[(1)]	6,555	$ 39.91		$ N/A
August 1 to August 31, 2007				N/A
September 1 to September 30, 2007[(1)]	27,704	38.54		N/A
	34,259	$ 38.80		$ N/A

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

Item 6. Exhibits

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, Executive Chairman[(1)]

31.2 Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer[(1)]

32.1 Section 1350 Certification of Principal Executive Officer, Owen Kratz, Executive Chairman[(2)]

32.2 Section 1350 Certification of Principal Financial Officer, A. Wade Pursell, Chief Financial Officer[(2)]

99.1	Report of Independent Registered Public Accounting Firm(1)

(1) Filed herewith

(2) Furnished herewith

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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: November 2, 2007	By: **/s/ Owen Kratz** Owen Kratz Executive Chairman
Date: November 2, 2007	By: **/s/ A. Wade Pursell** A. Wade Pursell Executive Vice President and Chief Financial Officer

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OF
HELIX ENERGY SOLUTIONS GROUP, INC.

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, Executive Chairman(1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer(1)
32.1	Section 1350 Certification of Principal Executive Officer, Owen Kratz, Executive Chairman(2)
32.2	Section 1350 Certification of Principal Financial Officer, A. Wade Pursell, Chief Financial Officer(2)
99.1	Report of Independent Registered Public Accounting Firm(1)

(1) Filed herewith

(2) Furnished herewith