HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
August 05, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2009

or

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

Commission File Number 001-32936

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [ ] No [ ]

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

Large accelerated filer	Non-accelerated filer

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

As of July 31, 2009, 103,422,642 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	June 30, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 261,930	$ 223,613
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $273 and $5,905, respectively	215,116	427,856
Unbilled revenue	14,052	42,889
Costs in excess of billing	37,121	74,361
Other current assets	123,325	172,089
Current assets of discontinued operations	—	19,215
Total current assets	651,544	960,023
Property and equipment	4,160,962	4,742,051
Less — accumulated depreciation	(1,337,746)	(1,323,608)
	2,823,216	3,418,443
Other assets:		
Equity investments	393,405	196,660
Goodwill	77,515	366,218
Other assets, net	79,682	125,722
	$ 4,025,362	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 165,342	$ 344,807
Accrued liabilities	224,318	231,679
Income taxes payable	77,914	—
Current maturities of long-term debt	13,730	93,540
Current liabilities of discontinued operations	—	2,772
Total current liabilities	481,304	672,798
Long-term debt	1,348,713	1,933,686
Deferred income taxes	513,248	615,504
Decommissioning liabilities	181,096	194,665
Other long-term liabilities	8,981	81,637
Total liabilities	2,533,342	3,498,290
Convertible preferred stock	25,000	55,000

Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 98,333 and 91,972 shares issued, respectively	895,305	806,905
Retained earnings	571,609	417,940
Accumulated other comprehensive loss	(20,575)	(33,696)
Total controlling interest shareholders' equity	1,446,339	1,191,149
Noncontrolling interests	20,681	322,627
Total equity	1,467,020	1,513,776
	$ 4,025,362	$ 5,067,066

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

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
Net revenues:		
Contracting services	$ 404,647	$ 335,969
Oil and gas	89,992	194,161
	494,639	530,130
Cost of sales:		
Contracting services	312,502	245,241
Oil and gas	46,381	95,811
	358,883	341,052
Gross profit	135,756	189,078
Gain on oil and gas derivative commodity contracts	4,121	—
Gain on sale of assets, net	1,319	18,803
Selling and administrative expenses	(39,372)	(42,246)
Income from operations	101,824	165,635
Equity in earnings of investments	6,264	6,155
Gain on sale of Cal Dive common stock	59,442	—
Net interest expense and other	(7,468)	(20,615)
Income before income taxes	160,062	151,175
Provision for income taxes	(56,809)	(54,773)
Income from continuing operations	103,253	96,402
Income from discontinued operations, net of tax	9,836	1,205
Net income, including noncontrolling interests	113,089	97,607
Net income applicable to noncontrolling interests	(12,620)	(7,076)
Net income applicable to Helix	100,469	90,531
Preferred stock dividends	(250)	(880)
Net income applicable to Helix common shareholders	$ 100,219	$ 89,651
Basic earnings per share of common stock:		
Continuing operations	$ 0.92	$ 0.97
Discontinued operations	0.10	0.01
Net income per common share	$ 1.02	$ 0.98
Diluted earnings per share of common stock:		
Continuing operations	$ 0.85	$ 0.92

Discontinued operations	0.09	0.01
Net income per common share	$ 0.94	$ 0.93
Weighted average common shares outstanding:		
Basic	96,936	90,519
Diluted	105,995	95,718

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

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net revenues:		
Contracting services	$ 815,441	$ 606,687
Oil and gas	250,173	365,212
	1,065,614	971,899
Cost of sales:		
Contracting services	638,200	458,755
Oil and gas	130,448	205,483
	768,648	664,238
Gross profit	296,966	307,661
Gain on oil and gas derivative commodity contracts	78,730	—
Gain on sale of assets, net	1,773	79,916
Selling and administrative expenses	(80,725)	(88,414)
Income from operations	296,744	299,163
Equity in earnings of investments	13,767	16,971
Gain on sale of Cal Dive common stock	59,442	—
Net interest expense and other	(29,663)	(48,616)
Income before income taxes	340,290	267,518
Provision for income taxes	(121,728)	(97,473)
Income from continuing operations	218,562	170,045
Income from discontinued operations, net of tax	7,282	1,764
Net income, including noncontrolling interests	225,844	171,809
Net income applicable to noncontrolling interests	(18,173)	(7,313)
Net income applicable to Helix	207,671	164,496
Preferred stock dividends	(563)	(1,761)
Preferred stock beneficial conversion charges	(53,439)	—
Net income applicable to Helix common shareholders	$ 153,669	$ 162,735
Basic earnings per share of common stock:		
Continuing operations	$ 1.50	$ 1.75
Discontinued operations	0.08	0.02
Net income per common share	$ 1.58	$ 1.77

Diluted earnings per share of common stock:		
Continuing operations	$ 1.37	$ 1.68
Discontinued operations	0.07	0.02
Net income per common share	$ 1.44	$ 1.70
Weighted average common shares outstanding:		
Basic	96,077	90,511
Diluted	106,000	95,492

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

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash flows from operating activities:		
Net income, including noncontrolling interests	$ 225,844	$ 171,809
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities —		
Depreciation, depletion and amortization	157,289	170,361
Asset impairment charge and dry hole expense	63,499	17,028
Equity in (earnings) losses of investments, net of distributions	(3,697)	2,390
Amortization of deferred financing costs	2,903	2,720
Income from discontinued operations	(7,282)	(1,764)
Stock compensation expense	7,188	13,552
Amortization of debt discount	3,876	3,632
Deferred income taxes	19,917	(24,205)
Excess tax benefit from stock-based compensation	754	(2,567)
Gain on sale of assets	(1,773)	(79,916)
Unrealized gain on derivative contracts	(24,667)	—
Gain on sale of investment in Cal Dive common stock	(59,442)	—
Changes in operating assets and liabilities:		
Accounts receivable, net	(14,231)	15,164
Other current assets	15,704	3,349
Margin deposits	—	(73,200)
Income tax payable	124,531	107,083
Accounts payable and accrued liabilities	9,220	(73,863)
Other noncurrent, net	(90,640)	(61,867)
Cash provided by operating activities	428,993	189,706
Cash provided by (used in) discontinued operations	(6,121)	623
Net cash provided by operating activities	422,872	190,329
Cash flows from investing activities:		
	(238,402)	(554,730)

Capital expenditures		
Investments in equity investments	(454)	(708)
Distributions from equity investments, net	3,253	9,118
Increase in restricted cash	(15)	(400)
Proceeds from the sale of Cal Dive common stock	196,656	—
Reduction in cash from deconsolidation of Cal Dive	(112,995)	—
Proceeds from sales of properties	23,238	229,243
Cash used in investing activities	(128,719)	(317,477)
Cash provided by (used in) discontinued operations	20,874	(70)
Net cash used in investing activities	(107,845)	(317,547)

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash flows from financing activities:		
Repayment of Helix Term Notes	(2,163)	(2,163)
Borrowings on Helix Revolver	—	541,500
Repayments on Helix Revolver	(349,500)	(444,500)
Repayment of MARAD borrowings	(2,081)	(1,982)
Borrowings on CDI Revolver	100,000	32,500
Repayments on CDI Revolver	—	(23,000)
Repayments on CDI Term Notes	(20,000)	(40,000)
Deferred financing costs	(28)	(1,709)
Preferred stock dividends paid	(500)	(1,761)
Repurchase of common stock	(753)	(3,223)
Excess tax benefit from stock-based compensation	(754)	2,567
Exercise of stock options, net	—	2,138
Net cash provided by (used in) financing activities	(275,779)	60,367
Effect of exchange rate changes on cash and cash equivalents	(931)	444
Net increase (decrease) in cash and cash equivalents	38,317	(66,407)
Cash and cash equivalents:		
Balance, beginning of year	223,613	89,555
Balance, end of period	$ 261,930	$ 23,148

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 subsidiaries. On June 10, 2009, our ownership in Cal Dive International Inc. ("Cal Dive" or "CDI") was reduced to less than 50%. Accordingly, we ceased consolidating CDI as of that date and now account for our remaining approximate 26% interest under the equity method of accounting (Notes 3 and 4). 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, 2008 ("2008 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 periods ended June 30, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009. Our balance sheet as of December 31, 2008 included herein has been derived from the audited balance sheet as of December 31, 2008 included in our 2008 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 2008 Form 10-K.

Certain reclassifications were made to previously reported amounts in the condensed consolidated financial statements and notes thereto to make them consistent with the current presentation format, including the adoption of certain recent accounting pronouncements that require retrospective application (Note 3) and the presentation of a former business unit as discontinued operations (Note 2). We have conducted our subsequent events review through August 5, 2009, the date of our financial statements were filed with the Securities and Exchange Commission.

Note 2 – Company Overview

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

Contracting Services Operations
We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By "marginal", we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our "life of field" services are

segregated into four disciplines: construction, well operations, drilling, and production facilities. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board (“FASB”)

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Statement No. 131 Disclosures about Segments of an Enterprise and Related Information ("SFAS No. 131"): Contracting Services, Shelf Contracting and Production Facilities. Our Contracting Services business includes subsea construction, well operations, robotics and drilling. Our Shelf Contracting business represents the assets of CDI, of which we currently own approximately 26% (Note 4). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway"), Independence Hub, LLC ("Independence Hub") and Kommandor LLC ("Kommandor"). In April 2009, Kommandor LLC completed the initial conversion of the Helix Producer I ("HP I") vessel. The vessel is currently undergoing further modification to install top side production facilities. The completed vessel is expected to be ready for service in the first half of 2010, and is currently scheduled to be deployed to our deepwater Phoenix oil and gas field that is being developed in parallel with the planned delivery of the HP I.

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 of our contracting services business and to achieve incremental returns to our contracting services. Since 1992, we have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Discontinued Operations

On April 27, 2009, we sold Helix Energy Limited ("HEL"), our former reservoir technology consulting business, to a subsidiary of Baker Hughes Incorporated for $25 million. As a result of the sale of HEL, which entity's operations were conducted by its wholly owned subsidiary, Helix RDS Limited ("Helix RDS"), we have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements. HEL and Helix RDS were previously components of our Contracting Services segment. We recognized an $8.8 million gain on the sale of HEL. The operating results of HEL and Helix RDS were immaterial to our results for all periods presented.

Economic Outlook

The economic downturn and weakness in the equity and credit capital markets continue to lead to increased uncertainty regarding the outlook of the global economy. This uncertainty, coupled with the negative near-term outlook for global demand for oil and natural gas, resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. A decline in oil and gas prices negatively impacts our operating results and cash flows. Our stock price also significantly declined over the second half of 2008. The declines in our stock price and the prices of oil and natural gas were considered in association with our required annual impairment assessment of goodwill and properties at year end 2008, which resulted in significant impairment charges (see Note 2 of our 2008 Form 10-K). Our stock price decreased further in the first quarter of 2009 resulting in our assessment of our goodwill amounts as of March 31, 2009; however, no further impairments were required. Our stock price increased in the second quarter of 2009 and no assessment of goodwill was performed at June 30, 2009; however, we are required to continue to monitor our remaining $77.5 million of goodwill as of June 30, 2009, all of which is attributed to our Contracting Services segment.

Our Contracting Services segment may also be negatively impacted by low commodity prices as some of our customers, primarily oil and gas companies, have recently announced their intention to reduce capital spending. We forecast weaker demand for our contracting services for the remainder of 2009. With respect to our oil and gas operations, we hedged the price risk for a significant portion of our anticipated oil and gas production for 2009 when we entered into commodity hedges during 2008. These hedge contracts enable us to minimize our near-term cash flow risks related to declining commodity prices. As of August 5, 2009, the prices for these contracts are significantly higher than the forward market prices for both crude oil and natural gas over the remainder of 2009. In March 2009, we entered into additional derivative contracts for a portion of our forecasted 2010 natural gas production. In the

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second quarter of 2009, we entered into additional hedge contracts in the form of financial costless collars for a portion of our 2010 forecasted natural gas and crude oil production, and in July 2009 we entered into financial swap contracts for a portion of our 2010 oil production. See Note 19 for additional information regarding our oil and gas hedge contracts.

Note 3 – Recent Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and adopted this standard for all other assets and liabilities on January 1, 2009. The adoption of SFAS No. 157 had no material impact on our results of operations, financial condition and liquidity.

SFAS No. 157, among other things, defines fair value, establishes a consistent framework for measuring fair value and expands disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. SFAS No. 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. SFAS No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

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

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted in SFAS No. 157. The valuation techniques are as follows:

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at June 30, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	–	$ 38,631	–	$ 38,631	(c)
Foreign currency forwards	–	3,938	–	3,938	(c)
Liabilities:					
Gas swaps and collars	–	10,676	–	10,676	(c)

Interest rate swaps	–		4,213	–		4,213	(c)
Total	–	$	27,680	–	$	27,680	

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On June 30, 2009, we adopted FASB Staff Position (FSP) No. FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, (FSP FAS 157-4). FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with SFAS 157 when the volume and level of activity for the asset or liability have significantly decreased and includes guidance for identifying circumstances that indicate a transaction is not orderly. This guidance is necessary to maintain the overall objective of fair value measurements, which is that fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. The adoption of FSP FAS 157-4 had no impact on our results of operations, cash flows and financial condition.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. We adopted SFAS No. 160 on January 1, 2009, which is required to be adopted prospectively, except the following provisions must be adopted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recasting consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Effective January 1, 2009, in accordance with SFAS No. 160, we changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See Note 4 for disclosure of stock sales transactions that ultimately resulted in our loss of control of CDI.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 requires entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows or financial condition. See Note 19 below for additional disclosure regarding our derivative instruments.

In May 2008, the FASB issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). We adopted the FSP APB 14-1 effective January 1, 2009. FSP APB 14-1 requires retrospective application for all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). FSP APB 14-1 requires 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 is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This FSP changed the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

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Upon adoption of FSP APB 14-1, we recorded a discount of $60.2 million related to our Convertible Senior Notes. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012).

The following table sets forth the effect of retrospective application of FSP APB 14-1 and FSP EITF 03-06-1 Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities (Note 12) and discontinued operations on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

	Three Months Ended June 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 18,668	$ 20,615
Provision for Income taxes	55,925	54,773
Net income from continuing operations	98,858	96,402
Earnings per common share from continuing operations – Basic	$ 1.00	$ 0.97
Earnings per common share from continuing operations – Diluted	0.96	0.92

	Six Months Ended June 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 44,714	$ 48,616
Provision for Income taxes	99,557	97,473
Net income from continuing operations	174,311	170,045
Earnings per common share from continuing operations - Basic	$ 1.83	$ 1.75
Earnings per common share from continuing operations – Diluted	1.75	1.68

On June 30, 2009, we adopted Statement of Financial Accounting Standards No. 165, Subsequent Events (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, SFAS 165 sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of SFAS 165 had no impact on the our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

Note 4 – Reduction in Ownership of Cal Dive

At December 31, 2008 we owned approximately 57.2% of Cal Dive. As previously noted in Notes 1, 2 and 3, in the first half of 2009 we engaged in a number of transactions to sell a portion of our remaining ownership in Cal Dive by selling shares of Cal Dive common stock held by us. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. Because we retained control of CDI immediately after the transaction, the loss of approximately $2.9 million on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet.

On June 10, 2009, we sold 20 million shares of Cal Dive held by us pursuant to a secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $161.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 28%. On June 18, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive shares held by us pursuant to their overallotment option under the terms of the Offering. We received approximately $21.0 million of proceeds, net of underwriting fees, from such sale and our ownership of Cal Dive was reduced to our current approximate 26%. Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain on sale of Cal Dive common stock" in the accompanying condensed consolidated statement of operations. The $59.4 million amount included an approximate $27.1 million gain associated with the re-measurement of our remaining 26% ownership interest in Cal Dive at its fair value on June 10, 2009, the date of deconsolidation. Since we no longer hold a controlling interest in Cal Dive, we no longer consolidate Cal Dive effective June 10, 2009, and prospectively we will be accounting for our remaining ownership interest in Cal Dive under the equity method of accounting until we no longer have significant influence on Cal Dive's future business decisions.

Note 5 – Insurance Matters

In September 2008, we sustained damage to certain of our facilities resulting from Hurricane Ike. All of our segments were affected by the hurricane; however, the oil and gas segment suffered the substantial majority of our aggregate damages. While we sustained damage to our own production facilities from Hurricane Ike, the larger issue in terms of our production recovery involved damage to third party pipelines and onshore processing facilities. The timing of the repairs of these facilities was not subject to our control and some of these third party facilities remain out of service as of August 5, 2009. Our insurance policy, which covered all of our operated and non-operated producing and non-producing properties, was subject to an approximate $6 million of aggregate deductibles. We met our aggregate deductible in September 2008. We record our hurricane-related repair costs as incurred in our oil and gas cost of sales. We record insurance reimbursements when the realization of the claim for recovery of a loss is deemed probable.

In June 2009, we reached a settlement with the underwriters of our insurance policies related to damages from Hurricane Ike. Insurance proceeds received in the second quarter of 2009 totaled $102.6 million. Previously, we had received approximately $25.6 million of reimbursements under previously submitted Ike-related insurance claims. In the second quarter of 2009, we recorded a $43.0 million net reduction in our cost of sales in the accompanying condensed consolidated statements of operations representing the amount our insurance recoveries exceeded our costs during the second quarter of 2009. The cost reduction reflects the net proceeds of $102.6 million partially offset by $8.1 million of hurricane-related expenses incurred in the second quarter of 2009 and $51.5 million of hurricane related impairment charges, including $43.8 million of additional estimated asset retirement costs ("ARO") resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a "total loss" following the storm. We anticipate that over the remainder of 2009 we will incur approximately $5 million of additional hurricane- related repair expenses and the substantial majority of the asset retirement costs associated with our total loss properties. We are essentially complete with our hurricane repairs related to our Contracting Services and Shelf Contracting operations.

The following table summarizes the claims and reimbursements by segment that affected our costs of sales accounts under various insurance claims resulting from damages sustained by Hurricane Ike, primarily those claims and reimbursement recently settled under our energy insurance policy (in thousands):

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	Second Quarter 2009	Six Months Ended June 30, 2009	Since Inception in September 2008
Oil and gas:			
Hurricane repair costs	$ 7,427	$ 20,163	$ 42,714
ARO liability adjustments	43,812	43,812	48,065
Hurricane-related impairments	7,699	7,699	37,585
Insurance recoveries	(97,747)	(100,874)	(118,415)
Net (reimbursements) costs	$ (38,809)	$ (29,200)	$ 9,949
Contracting services:			
Hurricane repair costs	$ 317	$ 776	$ 6,026
Insurance recoveries	(2,249)	(2,726)	(4,863)
Net (reimbursements) costs	(1,932)	(1,950)	1,163
Shelf Contracting:			
Hurricane repair costs	383	610	4,547
Insurance recoveries	(2,611)	(2,611)	(4,945)
Net (reimbursements) costs	(2,228)	(2,001)	(398)
Totals:			
Hurricane repair costs	8,127	21,549	53,287
ARO liability adjustments	43,812	43,812	48,065
Hurricane-related impairments	7,699	7,699	37,585
Insurance recoveries	(102,607)	(106,211)	(128,223)
Net (reimbursements) costs	$ (42,969)	$ (33,151)	$ 10,714

After considerable negotiations we renewed our energy and marine insurance for the period July 1, 2009 to June 30, 2010. However, this insurance renewal did not include wind storm coverage as the premium and deductibles would have been relatively substantial for the underlying coverage provided. In order to mitigate potential loss to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a weather derivative (Catastrophic Bonds). The Catastrophic Bonds provide for payments of negotiated amounts should the eye of a Category 3 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The cost of these Catastrophic Bonds totaled approximately $13 million and the premium will be amortized over the next twelve months.

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Note 6 – Details of Certain Accounts (in thousands)

Other Current Assets consisted of the following as of June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
Other receivables	$ 18,100	$ 22,977
Prepaid insurance	2,486	18,327
Other prepaids	13,621	23,956
Inventory	28,826	32,195
Current deferred tax assets	5,152	3,978
Hedging assets	40,604	26,800
Income tax receivable	—	23,485
Gas imbalance	6,460	7,550
Other	8,076	12,821
	$ 123,325	$ 172,089

Other Assets, Net, consisted of the following as of June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
Restricted cash	$ 35,417	$ 35,402
Deposits	356	1,890
Deferred drydock expenses, net	10,266	38,620
Deferred financing costs	26,715	33,431
Intangible assets with definite lives, net	888	7,600
Other	6,040	8,779
	$ 79,682	$ 125,722

Accrued Liabilities consisted of the following as of June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
Accrued payroll and related benefits	$ 23,591	$ 46,224
Royalties payable	9,659	10,265
Current decommissioning liability	92,055	31,116
Unearned revenue	7,221	9,353
Billings in excess of costs	8,332	13,256
Accrued interest	29,306	34,299
Deposit	25,542	25,542

Hedge liability	6,792	7,687
Other	21,820	53,937
	$ 224,318	$ 231,679

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Note 7 – Convertible Preferred Stock

In January 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible stock (Series A-1 Cumulative Convertible Stock, par value $0.01 per share) convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd. ("Fletcher"). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27 per share. Pursuant to the agreement governing the preferred stock (the "Fletcher Agreement"), Fletcher was entitled to convert its investment in the preferred shares at any time, or redeem its investment in the preferred shares at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all its shares of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms of this redemption, which was recorded as a reduction to our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares delivered over the original 1,964,058 shares that were contractually required to be issued upon conversion but was limited to the $29.3 million of net proceeds we received from the issuance of the Series A-2 Cumulative Convertible Preferred Stock.

The Fletcher Agreement provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price ($2.767), then our right to pay dividends in our common stock is extinguished, and we are required to deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to Fletcher under the Fletcher Agreement. On February 25, 2009, the volume weighted average price of our common stock was below the minimum price, and on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. As a result of the reset of the conversion price, Fletcher would receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock, and which would result in additional beneficial conversion charges in our statement of operations. Under the existing terms of our Senior Credit Facilities (Note 9) we are not permitted to deliver cash to the holder upon a conversion of the Convertible Preferred Stock.

In connection with the reset of the conversion price of the Series A-1 Cumulative Convertible Preferred Stock to $2.767, we were required to recognize a $24.1 million charge to reflect the value associated with the additional 7,368,388 shares that will be required to be delivered upon any future conversion(s) over the 1,666,668 shares that were to be delivered under the original contractual terms. This $24.1 million charge was recorded as a beneficial conversion charge reducing our net income applicable to common shareholders. Similar to the beneficial conversion charge associated with the redemption of Series A-2 Cumulative Convertible Preferred Stock, the beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock is limited to the $24.1 million of net proceeds received upon its issuance.

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At June 30, 2009, we had $25 million of convertible preferred stock outstanding. The convertible preferred stock maintains its mezzanine presentation below liabilities but is not included as component of shareholders' equity, because we may, under certain instances, be required to settle any future conversions in cash. On July 23, 2009, Fletcher provided a notice of conversion informing us of its election to convert 15,000 shares of the Series A-1 Cumulative Convertible Preferred Stock into 5,421,033 shares of our common stock. We also paid the accrued and unpaid dividends associated with these shares in cash, the amount of which was immaterial at the time of the conversion notice. On July 27, 2009, the conversion was completed. Following the closing of this conversion, 10,000 shares of Series A-1 Cumulative Convertible Preferred Stock remain outstanding, representing $10 million of stated value, which are convertible into 3,614,023 shares of our common stock.

The common shares issuable in connection with this convertible preferred stock outstanding are included in our diluted earnings per share computations using the "if converted" method based on the applicable conversion price of $2.767 per share, meaning that for almost all future reporting periods in which we have positive earnings and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the applicable number of our shares (9,035,056 shares at June 30, 2009 and 3,614,023 shares in future periods as discussed above) will be included in our diluted shares outstanding amount.

Note 8 – 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.

Litigation and Claims

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were 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 royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded 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 order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable. We appealed this order on the same basis as the previous orders.

Other operators in the Deep Water 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, including ours. 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 filed a notice of appeal of that decision on December 21, 2007. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. The plaintiff petitioned the appellate court for rehearing; however, that petition was denied on April 14, 2009. The plaintiff has petitioned the United States Supreme Court for a writ of certiorari for the Supreme Court to review the Fifth Circuit Court's decision. There is no certainty that the Supreme Court will accept the case.

As a result of this dispute, we had been recording reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006, 2007 and 2008) plus interest at 5% for our portion of the Gunnison related MMS claim. The result of accruing these reserves since 2005 had reduced our oil and gas revenues. Following the decision of the United States Court of Appeals for the Fifth Circuit Court, we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues in the first quarter of 2009. Effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this disputed net revenue interest and are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

Property Sales

In the first quarter of 2009, we sold our interest in East Cameron Block 316 for gross proceeds of approximately $18 million. We recorded an approximate $0.7 million gain from the sale of East Cameron Block 316 which was partially offset by the loss on the sale of the remaining 10% of our interest in the Bass Lite field at Atwater Block 426 in January 2009. In the second quarter we sold three fields for gross proceeds of $0.8 million and resulting in an aggregate gain of $1.2 million, including transfer of the respective field's asset retirement obligations.

In March and April 2008, we sold an aggregate 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million (of which $30.5 million was recognized in second quarter 2008).

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, Oklahoma, New Mexico and Wyoming ("Onshore Properties") to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

Exploration and Other

As of June 30, 2009, we capitalized approximately $2.9 million of costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

Further, the following table details the components of exploration expense for the three and six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,	Six Months Ended June 30,

	2009	2008	2009	2008
Delay rental and geological and geophysical costs	$ 1,061	$ 1,438	$ 1,533	$ 3,378
Dry hole expense	422	36	426	(16)
Total exploration expense	$ 1,483	$ 1,474	$ 1,959	$ 3,362

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In the second quarter of 2009, we recorded an aggregate of approximately $63.1 million of impairment charges, which are reflected as a reduction to our cost of sales. These charges primarily reflect the approximate $51.5 million of impairment-related charges recorded to properties that were severely damaged by Hurricane Ike (Note 4). Separately, we also recorded $11.5 million of impairment charges to reduce the asset carrying value of four fields following reductions in their estimated proved reserves as evaluated at June 30, 2009.

In January 2008, the development well on Devil's Island (Garden Banks Block 344) was determined to be unsuccessful and in the first half of 2008, we recorded an impairment charge of $14.6 million that is included as a component of oil and gas cost of sales in the accompanying condensed statement of operations.

Note 9 – 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 June 30, 2009 and December 31, 2008, our restricted cash totaled $35.4 million and is included in other assets, net. All of our restricted cash relates to funds required to be escrowed to cover the future decommissioning liabilities associated with the South Marsh Island 130, which we acquired in 2002. We have fully satisfied the escrow requirements under this agreement and may use the restricted cash for future decommissioning of the related field.

The following table provides supplemental cash flow information for the six months ended June 30, 2009 and 2008 (in thousands):

	Six Months Ended June 30,	
	2009	2008
Interest paid, net of capitalized interest(1)	$ 35,367	$ 13,174
Income taxes paid	$ 20,442	$ 15,480

Non-cash investing activities for the six months ended June 30, 2009 included $50.0 million of accruals for capital expenditures. Non-cash investing activities for the six months ended June 30, 2008 totaled $19.5 million. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

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Note 10 – Equity Investments

As of June 30, 2009, we have the following material investments, both of which are included within our Production Facilities segment and 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 $104.3 million and $106.3 million as of June 30, 2009 and December 31, 2008, respectively (including capitalized interest of $1.6 million at June 30, 2009 and December 31, 2008, respectively). Distributions from Deepwater Gateway, net to our interest, totaled $3.5 million in the first half of 2009.

· 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. First production began in July 2007. Our investment in Independence was $88.8 million and $90.2 million as of June 30, 2009 and December 31, 2008, respectively (including capitalized interest of $5.7 million and $5.9 million at June 30, 2009 and December 31, 2008, respectively). Distributions from Independence, net to our interest, totaled $13.2 million in the first half of 2009.

Also included within our Production Facilities segment is our investment in Kommandor LLC, the results of which we consolidate in our financial statements. As previously disclosed in Note 4, in June 2009 we sold shares of Cal Dive common stock representing approximately 50% of our 51% ownership of Cal Dive. Accordingly on June 10, 2009 we deconsolidated Cal Dive from our financial statements and effective June 11, 2009, our remaining ownership interest in Cal Dive is accounted for using the equity method. Our investment in Cal Dive was $200.3 million at June 30, 2009.

Note 11 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of June 30, 2009 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes	MARAD Debt	Other(1)	Total
Less than one year	$ 4,326	$	$	$	$ 4,318	$ 5,086	$ 13,730
One to two years	4,326				4,533		8,859
Two to three years	4,326				4,760		9,086
Three to four years	4,326				4,997		9,323
Four to five years	399,625				5,247		404,872
Over five years			550,000	300,000	97,513		947,513
Total debt	416,929		550,000	300,000	121,368	5,086	1,393,383

Current maturities	(4,326)				(4,318)	(5,086)	(13,730)
Long-term debt, less current maturities	$412,603	$	$ 550,000	$ 300,000	$ 117,050	$	$1,379,653
Unamortized debt discount (2)				(30,940)			(30,940)
Long-term debt	$412,603	$	$ 550,000	$ 269,060	$ 117,050	$	$1,348,713

(1) Reflects $5 million loan provided by Kommandor RØMØ to Kommandor LLC.

(2) Reflects debt discount resulting from adoption of APB 14-1 on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

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We had unsecured letters of credit outstanding at June 30, 2009 totaling approximately $12.2 million. These letters of credit primarily guarantee various contract bids, contractual performance, insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three and six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Interest expense	$ 27,612	$ 31,617	$ 57,463	$ 68,424
Interest income	(98)	(556)	(362)	(1,556)
Capitalized interest	(11,870)	(9,602)	(19,490)	(20,573)
Interest expense, net	$ 15,644	$ 21,459	$ 37,611	$ 46,295

Included below is a summary of certain components of our indebtedness. At June 30, 2009 and December 31, 2008, we were in compliance with all debt covenants. For additional information regarding our debt see Note 11 of our 2008 Form 10-K.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Cal Dive I -Title XI, Inc. and our foreign subsidiaries are not guarantors. CDI and its subsidiaries were not guarantors of the Senior Unsecured Notes prior to deconsolidation of CDI in June 2009 (Note 4). We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our senior secured credit facilities (see below).

Senior Credit Facilities

In July 2006, we entered into a credit agreement (the "Senior Credit Facilities") under which we borrowed $835 million in a term loan (the "Term Loan") and were initially able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition (see Note 4 of our 2008 Form 10-K). This facility was subsequently amended in November 2007, and as part of that amendment, an accordion feature was added that allows for increases in the Revolving Credit Facility up to an additional $150 million, subject to availability of borrowing capacity provided by new or existing lenders. In May 2008, we completed a $120 million increase in the Revolving Credit Facility utilizing this accordion feature. Total borrowing capacity under the Revolving Credit Facility now totals $420 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit.

The Term Loan matures on July 1, 2013 and is subject to quarterly scheduled principal payments. As a result of a $400 million prepayment made in December 2007, the quarterly scheduled principal payment was reduced from $2.1 million to $1.1 million. The Revolving Loans mature on July 1, 2011. We had no amounts drawn on the Revolving Credit Facility at June 30, 2009 and our availability under the Facility totaled $407.8 million net of $12.2 million of unsecured letters of credit issued.

The Term Loan currently bears interest either at the one-, three- or six-month LIBOR at our current election plus a 2.00% margin. Our average interest rate on the Term Loan for the six months ended June 30, 2009 and 2008 was approximately 3.1% and 5.7%, respectively, including the effects of our interest rate swaps (see below). The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our current election plus a margin ranging from 1.00% to 2.25%

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on LIBOR loans or 0% to 1.25% on Base Rate loans. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement. Our average interest rate on the Revolving Loans for the six months ended June 30, 2009 was approximately 3.4%.

Convertible Senior Notes

In March 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 (March 2025) under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. During the first half of 2009, no conversion triggers were met. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012 (see Note 11 of our 2008 Form 10-K). As a result of adopting FSP APB 14-1 (Note 3), the effective interest is 6.6%.

Approximately 1,199,000 shares and 965,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three month and six months ended June 30, 2008, respectively, because our average share price for the period was above the conversion price of approximately $32.14 per share. Our average share price was below the $32.14 per share conversion price for the three and six month periods ended June 30, 2009 and as a result there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes in those respective periods. 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 Convertible Senior Notes are convertible into a maximum 13,303,770 shares of our common stock.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments 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 Senior Unsecured Notes, amended Senior Credit Facilities, Convertible Senior Notes and 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 June 30, 2009, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

Other

Deferred financing costs of $26.7 million and $33.4 million are included in other assets, net as of June 30, 2009 and December 31, 2008, respectively, and are being amortized over the life of the respective loan agreements.

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Note 12 – Income Taxes

The effective tax rate for the three month and six month periods ended June 30, 2009 was 35.5% and 35.8%, respectively, compared with 36.2% and 36.4% for the three month and six month periods ended June 30, 2008, respectively. The effective tax rates for 2009 decreased as a result of the deconsolidation of CDI and not having any nondeductible goodwill as we did in the same prior year period. This decrease in the rate was partially offset by the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production.

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

Note 13 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three and six month periods ended June 30, 2009 and 2008 were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income, including noncontrolling interests	$ 113,089	$ 97,607	$ 225,844	$ 171,809
Other comprehensive income (loss), net of tax				
Foreign currency translation gain	30,650	1,586	27,032	2,393
Unrealized loss on hedges, net	(8,873)	(3,857)	(13,338)	(6,304)
Total other comprehensive income (loss)	21,777	(2,271)	13,694	(3,911)
Less: Other comprehensive loss applicable to noncontrolling interest	(12,333)	(7,226)	(17,880)	(7,464)
Total other comprehensive income (loss) applicable to Helix	$ 9,444	$ (9,497)	$ (4,186)	$ (11,375)

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

	June 30, 2009	December 31, 2008
Cumulative foreign currency translation adjustment	$ (15,935)	$ (42,874)
Unrealized gain (loss) on hedges, net	(4,640)	9,178
Accumulated other comprehensive loss	$ (20,575)	$ (33,696)

Note 14 – Earnings Per Share

On January 1, 2009, we adopted FSP No. EITF 03-06-1, “Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities.” We have shares of restricted stock issued and outstanding, some of which remain subject to certain vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under FSP 03-06-1, the undistributed earnings for each period are allocated based on the contractual participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Under FSP 03-06-1, we are required to compute EPS amounts under the two class method. We have revised the prior periods EPS amounts to reflect the current year adoption of FSP 03-06-1 (see table below).

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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 month and six month periods ended June 30, 2009 and 2008 are as follows (in thousands):

	Three Months Ended June 30, 2009		Three Months Ended June 30, 2008	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$100,219		$ 89,651	
Less: Undistributed net income allocable to participating securities	(1,526)		(1,171)	
Undistributed net income applicable to common shareholders	98,693		88,480	
(Income) loss from discontinued operations	(9,836)		(1,205)	
Add: Undistributed net income from discontinued operations allocable to participating securities	150		16	
Income per common share – continuing operations	$ 89,007	96,936	$ 87,291	90,519

	Three Months Ended June 30, 2009		Three Months Ended June 30, 2008	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share –continuing operations – Basic	$ 89,007	96,936	$ 87,291	90,519
Effect of dilutive securities:				
Stock options		24		369
Undistributed earnings reallocated to participating securities	116		62	
Convertible Senior Notes				1,199
Convertible preferred stock	250	9,035	880	3,631
Income per common share continuing operations	89,373		88,233	
Income (loss) per common share discontinued operations	9,836		1,205	
Net income (loss) per common share	$ 99,209	105,995	$ 89,438	95,718

	Six Months Ended June 30, 2009		Six Months Ended June 30, 2008	
	Income	Shares	Income	Shares
Basic:				
Net income applicable to common shareholders	$153,669		$162,735	
Less: Undistributed net income allocable to participating securities	(2,305)		(2,194)	
Undistributed net income applicable to common shareholders	151,364		160,541	
(Income) loss from discontinued operations	(7,282)		(1,764)	
Add: Undiscounted net income from discontinued operations allocable to participating securities	109		24	
Income per common share – continuing operations	$144,191	96,077	$158,801	90,511

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	Six Months Ended June 30, 2009		Six Months Ended June 30, 2008	
	Income	Shares	Income	Shares
Diluted:				
Net income per common share – continuing operations – Basic	$ 144,191	96,077	$ 158,801	90,511
Effect of dilutive securities:				
Stock options				385
Undistributed earnings reallocated to participating securities	203		111	
Convertible Senior Notes				965
Convertible preferred stock	563	9,923	1,761	3,631
Income per common share continuing operations	144,957		160,673	
Income (loss) per common share discontinued operations	7,282		1,764	
Net income (loss) per common share	$ 152,239	106,000	$ 162,437	95,492

There were no dilutive stock options for the six month period ended June 30, 2009 as the option strike price was below the average market price for the period ($7.50 per share). The cumulative $53.4 million of beneficial conversion charges that were realized and recorded during the first quarter of 2009 following the transaction affecting our convertible preferred stock (Note 7) are not included as an addition to adjust earnings applicable to common stock for our diluted earnings per share calculation.

The following table compares EPS as originally reported and EPS under the two-class method, pursuant to FSP EITF 03-6-1, to quantify the per common share impact of the new standard on total net income applicable to Helix common shareholders' for the three and six months ended June 30, 2008.

	Three Months	Six Months
Basic, as previously reported	$ 1.00	$ 1.83
Basic, impact of adoption of APB 14-1	(0.01)	(0.03)
Basic, restated for adoption of APB 14-1	0.99	1.80
Impact of FSP EITF 03-06-1 on basic EPS	(0.01)	(0.03)
Basic, under FSP EITF 03-06-1	0.98	1.77
Diluted, as previously reported	0.96	1.75
Diluted, impact of adoption of APB 14-1	(0.02)	(0.03)
Diluted, restated for adoption of APB 14-1	0.94	1.72
Impact of FSP EITF 03-06-1 on diluted EPS	(0.01)	(0.02)
Diluted, under FSP EITF 03-06-1	$ 0.93	$ 1.70

Note 15 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the “1995 Incentive Plan”) and the 2005 Long-Term Incentive Plan, as amended (the “2005 Incentive Plan”). As of June 30, 2009, there were approximately 1.8 million shares available for grant under our 2005 Incentive Plan.

During the first half of 2009, we made the following restricted share or restricted stock unit grants to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 incentive plan:

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Date of Grant	Type	Shares	Market Value Per Share	Vesting Period
January 2, 2009	(1)	343,368	$ 7.24	20% per year over five years
January 2, 2009	(2)	26,506	7.24	20% per year over five years
January 2, 2009	(1)	10,617	7.24	100% on January 2, 2011
February 26, 2009	(1)	141,975	2.70	20% per year over five years
April 1, 2009	(1)	4,195	5.14	100% on January 2, 2011
May 13, 2009	(1)	10,974	10.57	20% per year over five years

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three month and six month periods ended June 30, 2009 and 2008.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. All of our remaining stock options outstanding have fully vested and as such, there was no stock compensation expense related to them during the three months ended June 30, 2009. For the six month period ended June 30, 2009 approximately $0.1 million was recognized as compensation expense related to unvested stock options. For the three and six month periods ended June 30, 2009, $2.3 million and $4.6 million, respectively, was recognized as compensation expense related to unvested restricted shares. For the three and six month periods ended June 30, 2008, $0.3 million and $0.9 million, respectively, was recognized as compensation expense related to stock options (of which $0.1 million and $0.6 million for the three and six month periods ended June 30, 2008, respectively, was related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers). For the three and six month periods ended June 30, 2008, $4.5 million and $11.5 million, respectively, was recognized as compensation expense related to restricted shares and restricted stock units (of which $0.5 million and $3.6 million, respectively, was related to the accelerated vesting of restricted shares per the separation agreements between the Company and two of our former executive officers).

Stock Purchase Plan

In June 2009, we announced that we intend to purchase up to 1.5 million shares of our common stock as permitted under our principal credit facility. Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity grants made pursuant to our stock-based compensation plans. We may continue to make repurchases pursuant to this authority from time to time as additional equity grants are made under our stock based compensation plans based upon prevailing market conditions and other factors. All repurchases may be commenced or suspended at any time at the discretion of management. As of the time of this filing, we have repurchased a total of 396,431 shares of our common stock for $4.3 million (42,500 shares for $0.4 million as of June 30, 2009). We have retired all the shares we repurchased.

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Note 16 – Business Segment Information (in thousands)

Our operations are conducted through the following lines of business: contracting services and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 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. Contracting Services operations include subsea construction, well operations, robotics and drilling. Shelf Contracting operations consist of CDI, of which the assets are deployed primarily for diving-related activities and shallow water construction. On June 10, 2009, we ceased consolidating CDI when our remaining ownership interest decreased to 28% following the sale of a portion of CDI common stock held by us (Note 4). We continue to disclose the results of Shelf Contracting business as a segment up to and through June 10, 2009. All material intercompany transactions between the segments have been eliminated.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues				
Contracting Services	$ 239,476	$ 217,943	$ 470,331	$ 392,661
Shelf Contracting (1)	197,656	171,970	404,709	316,541
Oil and Gas	89,992	194,161	250,173	365,212
Production Facilities	5,472	—	5,472	—
Intercompany elimination	(37,957)	(53,944)	(65,071)	(102,515)
Total	$ 494,639	$ 530,130	$ 1,065,614	$ 971,899
Income from operations				
Contracting Services	$ 23,383	$ 36,312	$ 52,612	$ 56,493
Shelf Contracting (1)	38,145	29,498	59,077	37,046
Oil and Gas	42,945	104,202	188,128	214,119
Production Facilities equity investments(2)	(1,018)	(156)	(1,152)	(294)
Intercompany elimination	(1,631)	(4,221)	(1,921)	(8,201)
Total	$ 101,824	$ 165,635	$ 296,744	$ 299,163
Equity in earnings of equity investments	$ 6,264	$ 6,155	$ 13,767	$ 16,971

(1) Includes operations of Cal Dive through June 10, 2009 prior to its deconsolidation (Note 4).

(2) Includes selling and administrative expense of Production Facilities incurred by us. See equity in earnings of equity investments for earnings contribution.

	June 30, 2009	December 31, 2008

Identifiable Assets		
Contracting Services (1)	$ 1,926,411	$ 1,572,618
Shelf Contracting	—	1,309,608
Oil and Gas	1,631,525	1,708,428
Production Facilities	467,426	457,197
Discontinued operations	—	19,215
Total	$ 4,025,362	$ 5,067,066

(1) Includes our remaining investment in Cal Dive which totaled $200.3 million at June 30, 2009.

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Intercompany segment revenues during the three and six months ended June 30, 2009 and 2008 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Contracting Services	$ 28,951	$ 42,674	$ 52,854	$ 84,894
Shelf Contracting	4,654	11,270	7,865	17,621
Production Facilities	4,352	—	4,352	—
Total	$ 37,957	$ 53,944	$ 65,071	$ 102,515

Intercompany segment profits during the three and six months periods ended June 30, 2009 and 2008 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Contracting Services	$ 1,551	$ 2,959	$ 1,447	$ 5,822
Shelf Contracting	109	1,262	503	2,379
Production Facilities	(29)	—	(29)	—
Total	$ 1,631	$ 4,221	$ 1,921	$ 8,201

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. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 76% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees. Production began in December 2003. Payments to OKCD from us totaled $2.6 million and $5.4 million in the three and six months ended June 30, 2009, respectively, and $5.7 million and $11.2 million in the three and six months ended June 30, 2008, respectively.

In June 2009, our Chief Executive Officer, Owen Kratz, purchased 23,000 shares of Cal Dive common stock at $8.50 per share (aggregate consideration of $195,500) under the terms of a secondary offering of shares of Cal Dive held by us (Note 4).

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 range between $210 million and $230 million, of which approximately $168 million had been incurred, with an additional $2.7 million committed, at June 30, 2009. The Caesar is expected to join our fleet in late 2009.

We are also constructing the Well Enhancer, a multi-service dynamically positioned dive support/well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. Total construction cost for the Well Enhancer is expected to range between $200 million to $220 million. We expect the Well Enhancer to join our fleet and commence work in the third quarter of 2009. At June 30, 2009, we had incurred approximately $195 million, with an additional $4.5 million committed to this project.

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Further, we, along with Kommandor Rømø, a Danish corporation, formed Kommandor LLC, a joint venture, to convert a ferry vessel into a floating production unit named the Helix Producer I. The total cost of the ferry and the conversion is estimated to range between $160 million and $170 million. We have provided $97.5 million in construction financing through June 30, 2009 to the joint venture on terms consistent with an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by Helix through equity contributions. Under the terms of the operating agreement for the joint venture, if Kommandor Rømø elects not to make further contributions to the joint venture, the ownership interests in the joint venture will be adjusted based on the relative contributions of each member (including guarantees of indebtedness) to the total of all contributions and project financing guarantees.

Upon completion of the initial conversion, which occurred in April 2009, we chartered the Helix Producer I from Kommandor LLC, and plan to install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for use on our Phoenix oil and gas field. The cost of these additional facilities is estimated to range between $180 million and $190 million and the work is expected to be completed in the first half of 2010. As of June 30, 2009, approximately $220 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $1.0 million committed. The total estimated cost of the vessel, initial conversion and the additional facilities will range approximately between $340 million and $360 million. Kommandor LLC qualified as a variable interest entity under FIN 46(R). We determined that we were the primary beneficiary of Kommandor LLC and have consolidated its financial results in the accompanying consolidated financial statements. The operating results of Kommandor LLC are included within our Production Facilities segment. Kommandor LLC was a development stage enterprise since its formation in October 2006 until the completion of its initial conversion, which occurred in April 2009. Kommandor LLC is no longer a development stage enterprise.

In addition, as of June 30, 2009, we had also committed approximately $74.7 million in additional capital expenditures for exploration, development, and abandonment 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.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 “Accounting for Performance of Construction-Type and Certain Production-Type Contracts”. Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we have a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed by a third party and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We have paid $7.2 million of the $15.8 million estimated damages related to this terminated contact. We will continue to monitor our exposure under this contract until the job and all related disputes have been finalized.

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In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any exposure under the contract. Over the remainder of 2009, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUS") (approximately $21.8 million US dollars at June 30, 2009) and for liquidated damages at approximately $5 million AUS (approximately $4.0 million US dollars at June 30, 2009). At June 30, 2009, we have a $8.8 million AUS (approximately $7.1 million US dollars at June 30, 2009) claim against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work.

See Note 8 for information updating the litigation involving certain disputed royalty payments, which were recognized as oil and gas revenues in the first half of 2009.

Note 19 – Derivative Instruments and Hedging Activities

We are currently exposed to market risk in three major areas: commodity prices, interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign exchange currency fluctuations. All derivatives are reflected in our balance sheet at fair value unless otherwise noted, and do not contain credit-risk related or other contingent features that could cause accelerated payments when our derivative liabilities are in net liability positions.

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

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and the methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately if it is probable the forecasted transaction will not occur. If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in accumulated other comprehensive income are amortized to earnings over the remaining period of the original forecasted transaction.

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Commodity Price Risks

We manage commodity price risks through various financial costless collars and swap instruments and forward sales contracts that require physical delivery. We utilize these instruments to stabilize cash flows relating to a portion of our expected oil and gas production. Our costless collars and swap contracts were designated as hedges and initially qualified for hedge accounting. However, due to disruptions in our natural gas production as a result of damage caused by the hurricanes in third quarter 2008, all of our 2009 natural gas derivative contracts no longer qualify for hedge accounting and were effectively marked to market effective March 31, 2009. The costless collars and swap contracts for a portion of our 2010 forecasted oil and natural gas production were designated as cash flow hedges and currently qualify for hedge accounting. Our natural gas forward sales contracts were not within the scope of SFAS No. 133 as they qualified for the normal purchases and sales scope exception. However, due to disruptions in our production as a result of damages caused by the hurricanes mentioned above, they no longer qualify for the scope exception. Our oil forward sales contracts still qualify for the normal purchase and sales exemption under SFAS 133. As a result, future changes in the fair value of these instruments are now recorded through earnings as a component of our income from operations in the period the changes occur.

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

As of June 30, 2009, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling 2,100 MBbl of oil and 34,671 Mmcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
July 2009 — December 2009	Forward Sales(2)	150 MBbl	$71.79
January 2010 — December 2010	Collar(1)	100 MBbl	$62.50-$80.73
Natural Gas:			(per Mcf)
July 2009 — December 2009	Collar(3)	558.3 Mmcf	$7.00 — $7.90
July 2009 — December 2009	Forward Sales(4)	1,387.6 Mmcf	$8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$5.80
January 2010 — December 2010	Collar(1)	1,003.8 Mmcf	$6.00 — $6.70

(1) Designated as cash flow hedges, still deemed effective and qualifies for hedge accounting.
(2) Qualified for scope exemption as normal purchase and sale contract.
(3) Designated as cash flow hedges, deemed ineffective and subsequent changes in fair value are now being marked-to-market through earnings each period.
(4) No longer qualify for normal purchase and sale exemption and are now being marked-to-market through earnings each period.

Subsequent to June 30, 2009, we entered into three cash flow hedging swap agreements. The first contract covers 150 MBbl total at a price of $73.05 per barrel for the period from January to December 2010. The second contract covers 60 MBbl total at a price of $71.82 per barrel for the period from January to June 2010. The third contract covers 90 MBbl total at a price of $74.07 per barrel for the period July to December 2010.

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

Variable Interest Rate Risks

As the interest rates for some of our long-term debt are subject to market influences and will vary over the term of the debt, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our variable interest rate debt. As of June 30, 2009, we have entered into interest rate swaps to stabilize cash flows relating to $200 million of our Term Loan. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled “net interest expense and other”. Our interest rate swaps are effective.

Foreign Currency Exchange Risks

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

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of June 30, 2009 and December 31, 2008. As required by SFAS No. 161, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. As a result, the amounts below may not agree with the amounts presented on our condensed consolidated balance sheet and the fair value information presented for our derivative instruments (Note 3).

Derivatives designated as hedging instruments under SFAS No. 133 (in thousands):

	As of June 30, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil costless collars	Other current assets	$ —	Other current assets	$ 6,449
Gas costless collars	Other current assets	2,352	Other current assets	6,652
Oil swap contracts	Other current assets	—	Other current assets	1,019
Gas swap contracts	Other current assets	—	Other current assets	1,537
Foreign exchange forwards	Other current assets	—	Other current assets	506
		$ 2,352		$ 16,163

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	As of June 30, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Oil costless collars	Accrued liabilities	$ 2,462	Accrued liabilities	$ —
Gas swap contracts	Accrued liabilities	119	Accrued liabilities	—
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	240
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	1,378
Oil costless collars	Other long-term liabilities	3,082	Other long-term liabilities	—
Gas costless collars	Other long-term liabilities	1,116	Other long-term liabilities	—
Gas swap contracts	Other long-term liabilities	3,897	Other long-term liabilities	—
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	347
		$ 10,676		$ 1,965

Derivatives that are not currently designated as hedging instruments under SFAS No. 133 (in thousands):

	As of June 30, 2009		As of December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Gas costless collars	Other current assets	8,023	Other current assets	6,652
Gas forward sales contracts	Other current assets	28,256	Other current assets	3,987
Foreign exchange forwards	Other current assets	1,973	Other current assets	—
Foreign exchange forwards	Other assets, net	1,965	Other assets, net	—
		$ 40,217		$ 10,639
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	1,205
Interest rate swaps	Accrued liabilities	4,213	Accrued liabilities	6,242
		$ 4,213		$ 7,447

The following tables present the impact that derivative instruments designated as cash flow hedges had on our condensed consolidated statement of operations for the three and six months ended June 30, 2009 and 2008 (in thousands):

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2009(1)	2008	2009(1)	2008
Oil costless collars	$ (10,864)	$ (2,482)	$ (11,993)	$ (863)
Gas costless collars	1,236	648	1,236	(6,421)
Oil swap contracts	—	(8,290)	(1,019)	(8,290)
Gas swap contracts	(5,243)	—	(8,007)	—
Foreign exchange forwards	46	(11)	75	1,782
Interest rate swaps	25	3,361	(33)	2,363
	$ (14,800)	$ 6,774	$ (19,741)	$ (11,429)

(1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings within the next 12 months, except for amounts related to our foreign exchange forwards.

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	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Oil costless collars	Oil and gas revenue	$ 3,137	$ (9,050)	$ 6,429	$ (13,451)
Gas costless collars	Oil and gas revenue	3,138	(6,017)	4,791	(5,608)
Oil swap contracts	Oil and gas revenue	—	—	1,687	—
Gas swap contracts	Oil and gas revenue	—	—	2,954	—
Foreign exchange forwards	Cost of sales	—	93	—	93
Interest rate swaps	Net interest expense and other	(631)	(321)	(1,285)	(1,107)
		$ 5,644	$ (15,295)	$ 14,576	$ (20,073)

	Location of Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Foreign exchange forwards	Net interest expense and other	$ —	$ (1)	$ —	$ 1
Interest rate swaps	Net interest expense and other	—	6	—	(55)
		$ —	$ 5	$ —	$ (54)

The following tables present the impact that derivative instruments not designated as hedges had on our condensed consolidated income statement for the three and six months ended June 30, 2009 and 2008 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended June 30, 2009	2008	Six Months Ended June 30, 2009	2008
Gas costless collars	Gain on oil and gas derivative contracts	$ 2,496	$ —	$ 20,383	$ —
Gas forward sales contracts	Gain on oil and gas derivative contracts	1,626	—	58,347	—
Foreign exchange forwards	Net interest expense and other	4,497	14	5,143	14
Interest rate swaps	Net interest expense and other	(283)	—	(295)	(2,726)
		$ 8,336	$ 14	$ 83,578	$ (2,712)

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Note 20– Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive I-Title XI, Inc. Cal Dive and its subsidiaries were never guarantors of our Senior Unsecured Notes. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries related primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 245,520	$ 2,445	$ 13,965	$ —	$ 261,930
Accounts receivable, net	106,634	79,584	28,898	—	215,116
Unbilled revenue	39,020	—	12,153	—	51,173
Other current assets	50,018	93,815	15,181	(35,689)	123,325
Total current assets	441,192	175,844	70,197	(35,689)	651,544
Intercompany	98,600	142,478	(175,324)	(65,754)	—
Property and equipment, net	182,728	1,930,133	715,688	(5,333)	2,823,216
Other assets:					
Equity investments in unconsolidated affiliates	—	—	393,405	—	393,405
Equity investments in affiliates	2,356,701	29,212	—	(2,385,913)	—
Goodwill, net	—	45,107	32,408	—	77,515
Other assets, net	45,415	39,345	21,300	(26,378)	79,682
	$ 3,124,636	$ 2,362,119	$ 1,057,674	$ (2,519,067)	$ 4,025,362
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 72,416	$ 67,861	$ 25,025	$ 40	$ 165,342
Accrued liabilities	84,432	121,381	18,678	(173)	224,318
Income taxes payable	(27,201)	131,496	(14,800)	(11,581)	77,914
Current maturities of long-term debt	4,326	—	44,762	(35,358)	13,730

Total current liabilities	133,973	320,738	73,665	(47,072)	481,304
Long-term debt	1,231,663	—	117,050	—	1,348,713
Deferred income taxes	168,126	262,572	87,467	(4,917)	513,248
Decommissioning liabilities	—	175,408	5,688	—	181,096
Other long-term liabilities	—	8,084	821	76	8,981
Due to parent	(73,892)	(158,377)	99,377	132,892	—
Total liabilities	1,459,870	608,425	384,068	80,979	2,533,342
Convertible preferred stock	25,000				25,000
Total equity	1,639,766	1,753,694	673,606	(2,600,046)	1,467,020
	$ 3,124,636	$ 2,362,119	$ 1,057,674	$ (2,519,067)	$ 4,025,362

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

	As of December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 148,704	$ 4,983	$ 69,926	$ —	$ 223,613
Accounts receivable, net	125,882	97,300	204,674	—	427,856
Unbilled revenue	43,888	1,080	72,282	—	117,250
Other current assets	120,320	79,202	41,031	(68,464)	172,089
Current assets of discontinued operations	—	—	19,215	—	19,215
Total current assets	438,794	182,565	407,128	(68,464)	960,023
Intercompany	78,395	100,662	(101,813)	(77,244)	—
Property and equipment, net	168,054	2,007,807	1,247,060	(4,478)	3,418,443
Other assets:					
Equity investments in unconsolidated affiliates	—	—	196,660	—	196,660
Equity investments in affiliates	2,331,924	31,374	—	(2,363,298)	—
Goodwill, net	—	45,107	321,111	—	366,218
Other assets, net	48,734	37,967	68,035	(29,014)	125,722
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 99,197	$ 139,074	$ 107,856	$ (1,320)	$ 344,807
Accrued liabilities	87,712	65,090	83,233	(4,356)	231,679
Income taxes payable	(104,487)	82,859	9,149	12,479	—
Current maturities of long-term debt	4,326	—	173,947	(84,733)	93,540
Current liabilities of discontinued operations	—	—	2,772	—	2,772
Total current liabilities	86,748	287,023	376,957	(77,930)	672,798
Long-term debt	1,579,451	—	354,235	—	1,933,686
Deferred income taxes	184,543	242,967	191,773	(3,779)	615,504
Decommissioning liabilities	—	191,260	3,405	—	194,665
	—	73,549	10,706	(2,618)	81,637

Other long-term liabilities					
Due to parent	(100,528)	(3,741)	126,013	(21,744)	—
Total liabilities	1,750,214	791,058	1,063,089	(106,071)	3,498,290
Convertible preferred stock	55,000	—	—	—	55,000
Total equity	1,260,687	1,614,424	1,075,092	(2,436,427)	1,513,776
	$ 3,065,901	$ 2,405,482	$ 2,138,181	$ (2,542,498)	$ 5,067,066

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

	Three Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 93,906	$ 176,474	$ 255,165	$ (30,906)	$ 494,639
Cost of sales	79,650	118,281	190,069	(29,117)	358,883
Gross profit	14,256	58,193	65,096	(1,789)	135,756
Gain on oil and gas derivative commodity contracts	—	4,121	—	—	4,121
Gain on sale of assets, net	—	1,319	—	—	1,319
Selling and administrative expenses	(12,770)	(7,610)	(20,062)	1,070	(39,372)
Income from operations	1,486	56,023	45,034	(719)	101,824
Equity in earnings of unconsolidated affiliates	—	—	6,625	(361)	6,264
Equity in earnings (losses) of affiliates	71,904	1,642	—	(73,546)	—
Gain on sale of Cal Dive common stock	59,442	—	—	—	59,442
Net interest expense and other	(5,490)	(933)	(767)	(278)	(7,468)
Income before income taxes	127,342	56,732	50,892	(74,904)	160,062
Provision for income taxes	(25,571)	(19,276)	(12,441)	479	(56,809)
Income from continuing operations	101,771	37,456	38,451	(74,425)	103,253
Discontinued operations, net of tax	(424)	—	10,260	—	9,836
Net income, including noncontrolling interests	101,347	37,456	48,711	(74,425)	113,089
Net income applicable to noncontrolling interests	—	—	—	(12,620)	(12,620)
Net income applicable to Helix	101,347	37,456	48,711	(87,045)	100,469
Preferred stock dividends	(250)	—	—	—	(250)
Net income applicable to Helix common shareholders	$ 101,097	$ 37,456	$ 48,711	$ (87,045)	$ 100,219

	Three Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated

Net revenues	$ 90,099	$ 246,766	$ 251,377	$ (58,112)	$ 530,130
Cost of sales	84,747	132,756	176,777	(53,228)	341,052
Gross profit	5,352	114,010	74,600	(4,884)	189,078
Gain on oil and gas derivative commodity contracts	—	—	—	—	—
Gain on sale of assets, net	—	18,594	209	—	18,803
Selling and administrative expenses	(6,400)	(14,618)	(22,161)	933	(42,246)
Income from operations	(1,048)	117,986	52,648	(3,951)	165,635
Equity in earnings of unconsolidated affiliates	—	—	6,155	—	6,155
Equity in earnings (losses) of affiliates	101,516	(215)	—	(101,301)	—
Net interest expense and other	(1,808)	(11,205)	(6,970)	(632)	(20,615)
Income before income taxes	98,660	106,566	51,833	(105,884)	151,175
Provision for income taxes	(5,188)	(37,524)	(13,723)	1,662	(54,773)
Income from continuing operations	93,472	69,042	38,110	(104,222)	96,402
Discontinued operations, net of tax	—	—	1,205	—	1,205
Net income, including noncontrolling interests	93,472	69,042	39,315	(104,222)	97,607
Net income applicable to noncontrolling interests	—	—	—	(7,076)	(7,076)
Net income applicable to Helix	93,472	69,042	39,315	(111,298)	90,531
Preferred stock dividends	(880)	—	—	—	(880)
Preferred stock beneficial conversion charges	—	—	—	—	—
Net income applicable to Helix common shareholders	$ 92,592	$ 69,042	$ 39,315	$ (111,298)	$ 89,651

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

	Six Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$189,988	$ 412,731	$ 517,182	$ (54,287)	$ 1,065,614
Cost of sales	142,352	267,825	409,262	(50,791)	768,648
Gross profit	47,636	144,906	107,920	(3,496)	296,966
Gain on oil and gas derivative commodity contracts	—	78,730	—	—	78,730
Gain on sale of assets, net	—	1,773	—	—	1,773
Selling and administrative expenses	(24,630)	(15,880)	(42,574)	2,359	(80,725)
Income from operations	23,006	209,529	65,346	(1,137)	296,744
Equity in earnings of unconsolidated affiliates	—	—	14,128	(361)	13,767
Equity in earnings (losses) of affiliates	180,826	(2,162)	—	(178,664)	—
Gain on sale of Cal Dive common stock	59,442	—	—	—	59,442
Net interest expense and other	(14,609)	(6,115)	(7,952)	(987)	(29,663)
Income before income taxes	248,665	201,252	71,522	(181,149)	340,290
Provision for income taxes	(36,562)	(69,622)	(16,413)	869	(121,728)
Income from continuing operations	212,103	131,630	55,109	(180,280)	218,562
Discontinued operations, net of tax	(2,816)	—	10,098	—	7,282
Net income, including noncontrolling interests	209,287	131,630	65,207	(180,280)	225,844
Net income applicable to noncontrolling interests	—	—	—	(18,173)	(18,173)
Net income applicable to Helix	209,287	131,630	65,207	(198,453)	207,671
Preferred stock dividends	(653)	—	—	—	(653)
Preferred stock beneficial conversion charges	(53,349)	—	—	—	(53,349)
Net income applicable to Helix common shareholders	$155,285	$ 131,630	$ 65,207	$ (198,453)	$ 153,669

	Six Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$174,990	$ 448,462	$ 460,181	$ (111,734)	$ 971,899
Cost of sales	150,861	269,969	345,407	(101,999)	664,238
Gross profit	24,129	178,493	114,774	(9,735)	307,661
Gain on oil and gas derivative commodity contracts	—	—	—	—	—
Gain on sale of assets, net	—	79,707	209		79,916
Selling and administrative expenses	(17,295)	(29,077)	(44,076)	2,034	(88,414)
Income from operations	6,834	229,123	70,907	(7,701)	299,163
Equity in earnings of unconsolidated affiliates	—	—	16,971	—	16,971
Equity in earnings (losses) of affiliates	183,722	5,157	—	(188,879)	—
Net interest expense and other	(10,227)	(24,468)	(15,755)	1,834	(48,616)
Income before income taxes	180,329	209,812	72,123	(194,746)	267,518
Provision for income taxes	(13,122)	(71,048)	(16,477)	3,174	(97,473)
Income from continuing operations	167,207	138,764	55,646	(191,572)	170,045
Discontinued operations, net of tax	—	—	1,764	—	1,764
Net income, including noncontrolling interests	167,207	138,764	57,410	(191,572)	171,809
Net income applicable to noncontrolling interests	—	—	—	(7,313)	(7,313)
Net income applicable to Helix	167,207	138,764	57,410	(198,885)	164,496
Preferred stock dividends	(1,761)	—	—	—	(1,761)
Net income applicable to Helix common shareholders	$165,446	$ 138,764	$ 57,410	$ (198,885)	$ 162,735

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

	Six Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 209,287	$ 131,630	$ 65,207	$ (180,280)	$ 225,844
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	(4,058)	361	(3,697)
Equity in earnings of affiliates	(180,826)	2,162	—	178,664	—
Other adjustments	10,172	132,121	(132,954)	197,507	206,846
Cash provided by (used in) operating activities	38,633	265,913	(71,805)	196,252	428,993
Cash provided by discontinued operations	—	—	(6,121)	—	(6,121)
Net cash provided by (used in) operating activities	38,633	265,913	(77,926)	196,252	422,872
Cash flows from investing activities:					
Capital expenditures	(12,303)	(117,238)	(108,861)	—	(238,402)
Investments in equity investments	—	—	(454)	—	(454)
Distributions from equity investments, net	—	—	3,253	—	3,253
Proceeds from sale of Cal Dive common stock	282,656	—	(112,995)	(86,000)	83,661
Proceeds from sales of property	—	23,238	—	—	23,238
Other	—	(15)	—	—	(15)
Cash provided by (used in) investing activities	270,353	(94,015)	(219,057)	(86,000)	(128,719)
Cash provided by discontinued operations	—	—	20,874	—	20,874
Net cash provided by (used in) investing	270,353	(94,015)	(198,183)	(86,000)	(107,845)

activities					
Cash flows from financing activities:					
Borrowings on revolver	—	—	100,000	—	100,000
Repayments on revolver	(349,500)	—	—	—	(349,500)
Repayments of debt	(2,163)	—	(22,081)	—	(24,244)
Deferred financing costs	(28)	—	—	—	(28)
Preferred stock dividends paid	(500)	—	—		(500)
Repurchase of common stock	(753)	—	(86,000)	86,000	(753)
Excess tax benefit from stock-based compensation	(754)	—	—	—	(754)
Exercise of stock options, net					—
Intercompany financing	141,528	(174,436)	229,160	(196,252)	—
Net cash provided by (used in) financing activities	(212,170)	(174,436)	221,079	(110,252)	(275,779)
Effect of exchange rate changes on cash and cash equivalents	—	—	(931)	—	(931)
Net increase (decrease) in cash and cash equivalents	96,816	(2,538)	(55,961)	—	38,317
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of period	$ 245,520	$ 2,445	$ 13,965	$ —	$ 261,930

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

	Six Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 167,207	$ 138,764	$ 57,410	$ (191,572)	$ 171,809
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	2,304	—	2,304
Equity in earnings of affiliates	(183,722)	(5,157)	—	188,879	—
Other adjustments	77,798	(44,027)	(649)	(17,529)	15,593
Cash provided by (used in) operating activities	61,283	89,580	59,065	(20,222)	189,706
Cash provided by discontinued operations	—	—	623	—	623
Net cash provided by (used in) operating Activities	61,283	89,580	59,688	(20,222)	190,329
Cash flows from investing activities:					
Capital expenditures	(48,121)	(335,468)	(171,141)	—	(554,730)
Investments in equity investments	—	—	(708)	—	(708)
Distributions from equity investments, net	—	—	9,118	—	9,118
Proceeds from sales of property	—	228,483	760	—	229,243
Other	—	(400)	—	—	(400)
Cash provided by (used in) investing activities	(48,121)	(107,385)	(161,971)	—	(317,477)
Cash provided by discontinued operations	—	—	(70)	—	(70)
Net cash used in investing activities	(48,121)	(107,385)	(162,041)	—	(317,547)

Cash flows from financing activities:					
Borrowings on revolver	541,500	—	32,500	—	574,000
Repayments on revolver	(444,500)	—	(23,000)	—	(467,500)
Repayments of debt	(2,163)	—	(41,982)	—	(44,145)
Deferred financing costs	(1,709)	—	—	—	(1,709)
Preferred stock dividends paid	(1,761)	—	—	—	(1,761)
Repurchase of common stock	(3,223)	—	—	—	(3,223)
Excess tax benefit from stock-based compensation	2,567	—	—	—	2,567
Exercise of stock options, net	2,138	—	—	—	2,138
Intercompany financing	(106,681)	19,359	67,100	20,222	—
Net cash provided by (used in) financing activities	(13,832)	19,359	34,618	20,222	60,367
Effect of exchange rate changes on cash and cash equivalents	—	—	444	—	444
Net decrease in cash and cash equivalents	(670)	1,554	(67,291)	—	(66,407)
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439	—	89,555
Balance, end of period	$ 2,837	$ 4,163	$ 16,148	$ —	$ 23,148

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

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

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

- statements regarding our business strategy, including the potential sale of assets and/or other investments in our subsidiaries and facilities, or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed acquisition, exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related 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, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding any Securities and Exchange Commission ("SEC") or other governmental or regulatory inquiry or investigation;
- 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;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

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

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

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those described in Item 1A. “Risk Factors” in our 2008 Form 10-K and any quarterly report on Form 10-Q filed subsequently thereto. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

EXECUTIVE SUMMARY

Our Business

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

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Our Strategy

In December 2008, we announced our intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to:

1) Sell all or a portion of our oil and gas assets;
2) Divest our ownership interests in one or more of our production facilities; and
3) Dispose of our remaining interest in CDI.

The current economic and financial market conditions may affect the timing of any strategic dispositions by us and will require a degree of patience in order to execute any transactions. As a result, we are unable to be specific with respect to a timetable for any disposition, but we continue to focus on reducing debt levels through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals.

Since the announcement of our strategy to monetize certain of our non core business assets, we have:

- Sold two oil and gas properties for $67 million in gross proceeds;
- Sold approximately 13.6 million shares of CDI common stock held by us to CDI for $86 million in January 2009;
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million;
- Sold approximately 1.6 million shares of CDI common stock held by us to CDI for $14 million in June 2009; and
- Sold 22.6 million shares of CDI common stock held by us to third parties in a public secondary offering for approximately $183 million, net of underwriting fees.

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our oil and gas operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors.

Economic Outlook and Industry Influences

The economic downturn and weakness in the equity and credit capital markets continues to lead to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the negative near-term outlook for global demand for oil and gas has resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Prices for oil have increased in the second quarter of 2009 but remain significantly lower than the high prices achieved in second quarter of 2008. A decline in oil and gas prices negatively impacts our operating results and cash flow. Further, our contracting services are negatively impacted by declining commodity prices, which has resulted in some of our customers, primarily oil and gas companies, to recently announce reductions in capital spending. The long-term fundamentals for our business remain generally favorable as the continual effort to replenish oil and gas production should drive demand for our services. In addition, our subsea construction operations primarily support capital projects with long lead times that are less likely to be impacted by temporary economic downturns. We have economically hedged approximately two thirds of our anticipated production for the remainder of 2009 with a combination of forward sale and financial hedge contracts. We have also hedged a substantial portion of our anticipated oil and natural gas production for 2010 through the placement of additional swap and costless collar financial hedge contracts. The prices for these contracts are significantly higher than the prices for both crude oil and natural gas as of June 30, 2009. If the prices for crude oil and natural gas do not increase from current levels, and we have not entered into

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additional forward sale or financial hedge contracts to stabilize our cash flows, our oil and gas revenues may decrease in 2010 and beyond, perhaps significantly, absent offsetting increases in production amounts. For additional information regarding our oil and gas hedge contracts see Note 19.

At June 30, 2009, we had cash on hand of $261.9 million and $407.8 million available for borrowing under our revolving credit facilities. We have reduced our planned capital expenditures for 2009 to include primarily the completion of major vessel construction projects and limited oil and gas expenditures. If we successfully implement the business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Helix Revolving Credit Facility.

Our business is substantially dependent upon the condition of the oil and natural gas industry and, in particular, the willingness of oil and natural gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing views of future oil and natural gas prices, which are influenced by numerous factors, including but not limited to:

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

Global economic conditions have deteriorated significantly over the past year with declines in the oil and gas market accelerating during the fourth quarter of 2008 and continuing in the first quarter of 2009. Oil prices have advanced in the second quarter but natural gas prices still continue to be substantially lower as compared to prices received as recently as the third quarter of 2008. Predicting the timing and sustainability of any recovery in pricing is subjective and highly uncertain. Although we are currently in a recession, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long term increasing world demand for oil and natural gas; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) increasing number of subsea developments. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

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RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, and Production Facilities as well as Oil and Gas. As discussed below, in June 2009 we ceased consolidating our Shelf Contracting Business, which represents the results and operations of Cal Dive, following the sale of a substantial amount of our remaining ownership of Cal Dive (Note 4). Each line item within our condensed consolidated statement of operations for both the three month and six month periods is impacted significantly when compared to the prior year periods as a result of the deconsolidation of the Cal Dive results. Our 2009 consolidated results include Cal Dive's results through June 10, 2009, while we recorded our approximate 26% share of Cal Dive's results for the period June 11, 2009 through June 30, 2009 to equity in earnings of investments as required under the equity method of accounting. We continue to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. Our "life of field" services are organized in four disciplines: construction, well operations, production facilities, and drilling. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and drilling. The Cal Dive assets representing the Shelf Contracting segment are deployed primarily for diving-related activities and shallow water construction. Our Contracting Services business operates primarily in the Gulf of Mexico, the North Sea, Asia/Pacific and Middle East regions, with services that cover the lifecycle of an offshore oil or gas field. As of June 30, 2009, our contracting services operations had backlog of approximately $360 million. We expect that approximately $172 million of our backlog will be completed over the remainder of 2009. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

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

Discontinued Operations

On April 27, 2009, we sold Helix RSD Limited, our former reservoir technology consulting company, to a subsidiary of Baker Hughes Incorporated for $25 million. We have presented the results of Helix RDS as discontinued operations in the accompanying condensed consolidated financial statements (Note 2). Helix RDS was previously a component of our Contracting Services business. We recognized an $8.8 million gain on the sale of Helix RDS. The operating results of Helix RDS were immaterial to all periods presented in this Quarterly Report on Form 10-Q.

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Reduction in Ownership of Cal Dive

At December 31, 2008 we owned 57.2% of Cal Dive. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock held by us to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive and reduced our ownership in Cal Dive to approximately 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet.

On June 10, 2009, we sold 20 million shares of Cal Dive held by us pursuant to an underwritten secondary public offering ("Offering") Proceeds from the Offering totaled approximately $161.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 28%. On June 18, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive shares held by us pursuant to their overallotment option under the terms of the Offering. We received approximately $21.0 million of proceeds, net of underwriting fees, from such sale and our ownership of Cal Dive was reduced to our current approximate 26%. Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain on sale of Cal Dive common stock" in the accompanying condensed consolidated statement of operations. Since we no longer hold a controlling interest in Cal Dive, we no longer consolidate Cal Dive effective June 10, 2009, and prospectively we will be accounting for our remaining 26% ownership interest in Cal Dive under the equity method of accounting until we no longer have significant influence on Cal Dive's future business decisions. For more information regarding the reduction in our ownership in Cal Dive see Notes 1, 2, 3 and 4.

Comparison of Three Month Periods Ended June 30, 2009 and 2008

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$239,476	$217,943	$ 21,533
Shelf Contracting	197,656	171,970	25,686
Oil and Gas	89,992	194,161	(104,169)
Production Facilities	5,472	—	5,472
Intercompany elimination	(37,957)	(53,944)	15,987
	$494,639	$530,130	$ (35,491)
Gross profit (in thousands) –			
Contracting Services	$ 40,712	$ 47,693	$ (6,981)
Shelf Contracting	53,923	47,256	6,667
Oil and Gas (1)	43,611	98,350	(54,739)
Production Facilities	(859)	—	(859)
Intercompany elimination	(1,631)	(4,221)	2,590
	$135,756	$189,078	$ (53,322)
Gross Margin –			

Contracting Services	17%	22%	(5 pts)
Shelf Contracting	27%	27%	—
Oil and Gas	48%	51%	(3 pts)
Total company	27%	36%	(9 pts)

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	Three Months Ended June 30, 2009	2008
Number of vessels(2)/ Utilization(3) –		
Contracting Services:		
Offshore construction vessels	9/88%	8/93%
Well operations	2/98%	2/60%
ROVs	47/72%	42/70%

(1) In the second quarter of 2009 we received a total of $97.7 million of insurance proceeds associated with our oil and gas operations which were offset by $7.4 million of related hurricane repair cost and impairment charges totaling $51.5 million, including $43.8 million to increase the asset retirement obligations associated with properties that were considered a "total loss" following Hurricane Ike in September 2008.
(2) Represents number of vessels (including chartered vessels) as of the end of the period excluding acquired vessels prior to their in-service dates, and vessels taken out of service prior to their disposition.
(3) 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 June 30, 2009 and 2008 were as follows (in thousands):

	Three Months Ended June 30, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 28,951	$ 42,674	$ (13,723)
Shelf Contracting(1)	4,654	11,270	(6,616)
Production Facilities	4,352	—	4,352
	$ 37,957	$ 53,944	$ (15,987)

(1) Excludes the 20 days from June 11, 2009 to June 30, 2009 following the deconsolidation of Cal Dive from our condensed consolidated financial statements.

Intercompany segment profit during the three month periods ended June 30, 2009 and 2008 was as follows (in thousands):

	Three Months Ended June 30, 2009	2008	Increase/ (Decrease)
Contracting Services	$ 1,551	$ 2,959	$ (1,408)
Shelf Contracting(1)	109	1,262	(1,153)
Production Facilities	(29)	—	(29)
	$ 1,631	$ 4,221	$ (2,590)

(1) Excludes the 20 days from June 11, 2009 to June 30, 2009 following the deconsolidation of Cal Dive from our condensed consolidated financial statements.

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

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	Three Months Ended June 30, 2009	2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	806	897	(91)
Oil sales revenue (in thousands)	$ 58,264	$ 94,591	$ (36,327)
Average oil sales price per Bbl (excluding hedges)	$ 68.40	$ 115.57	$ (47.17)
Average realized oil price per Bbl (including hedges)	$ 72.29	$ 105.48	$ (33.19)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$(29,763)		
Change in production volume (in thousands)	(6,564)		
Total decrease in oil sales revenue (in thousands)	$(36,327)		
Gas production volume (MMcf)	7,535	9,492	(1,957)
Gas sales revenue (in thousands)	$ 31,737	$ 98,363	$ (66,626)
Average gas sales price per mcf (excluding hedges)	$ 3.80	$ 11.00	$ (7.20)
Average realized gas price per mcf (including hedges recorded as gas sales revenue)	$ 4.21	$ 10.36	$ (6.15)
Average realized gas price per mcf (including hedges recorded as revenues and gain on oil and gas derivative contracts	$ 7.62	$ 10.36	$ (2.74)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$(58,383)		
Change in production volume (in thousands)	(8,243)		
Total decrease in gas sales revenue (in thousands)	$(66,626)		
Total production (MMcfe)	12,371	14,873	(2,502)
Revenue price per Mcfe, including hedges	$ 7.28	$ 12.97	$ (5.69)
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 90,002	$192,954	$ (102,952)
Miscellaneous revenues(1)	(10)	1,207	(1,217)
	$ 89,992	$194,161	$ (104,169)

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

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

	Three Months Ended June 30,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 17,867	$ 1.44	$ 23,995	$ 1.61
Workover (3)	915	0.07	3,964	0.27
Transportation	2,183	0.18	2,184	0.15
Repairs and maintenance	2,402	0.19	5,728	0.39
Overhead and company labor	2,866	0.23	1,134	0.07
Total	$ 26,233	$ 2.11	$ 37,005	$ 2.49
Depletion expense	$ 41,182	$ 3.33	$ 50,951	$ 3.43
Abandonment	786	0.06	2,818	0.19
Accretion expense	4,059	0.33	3,257	0.22
Impairment (4)	11,446	0.93	306	0.02
Net hurricane (reimbursements) costs (5)	(38,809)	(3.14)	-	-

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(1) Excludes exploration expense of $1.5 million for each of the three months ended June 30, 2009 and 2008. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Excludes all hurricane-related cost and charges resulting from Hurricane Ike in September 2008 (see (5) below).

(4) Amount for 2009 period reflects charge to reduce the carrying value of four fields to their estimated net realizable value following reductions in their estimated proved reserves at June 30, 2009.

(5) Represents the amount of net proceeds in excess of previously incurred costs and related impairment charges. In the second quarter we received a total of $97.7 million of insurance proceeds associated with our oil and gas operations which were offset by $7.4 million of related hurricane repair cost and impairment charges totaling $51.5 million, including $43.8 million to increase the asset retirement obligations associated with properties that were considered a total loss following Hurricane Ike in September 2008.

Revenues. During the three months ended June 30, 2009, our total revenues decreased by 7% as compared to the same period in 2008 reflecting reduced oil and gas revenues as discussed below. Contracting Services revenues increased 10% during the three month period ended June 30, 2009 as compared to the same period in 2008. The increase primarily reflects strong performance from our robotics subsidiary as well as increased utilization of the Q4000 that was out of service a significant portion of the first half of 2008. Shelf Contracting revenues increased 15% primarily as a result of new international construction activities and increased demand for repair and salvage work following the hurricanes that affected the Gulf of Mexico in the third quarter of 2008 and higher vessel utilization. This increase in Shelf Contracting occurred despite having 20 less days in the second quarter 2009 period as a result of the deconsolidation of Cal Dive effect June 10, 2009 (see "Reduction of Cal Dive Ownership" above and Note 4).

Oil and Gas revenues decreased by 54% during the three month period ended June 30, 2009 as compared to the same period in 2008. The decrease reflects a significant decrease in both oil and natural gas prices which were approaching historical highs in the second quarter 2008. The decrease in oil revenues was attributable to a 31% decrease in realized oil prices with slightly lower production compared with the same prior year period. The decrease in gas revenues was attributable to a 59% decrease in realized gas prices and a 21% decrease in gas production, which was impacted by repairs being made to certain third party pipelines that were damaged by the hurricanes in 2008. Repairs to a key third party pipeline continue, which when completed would benefit our production as this particular pipeline provides service to our Noonan gas field, where production has been curtailed since it commenced production in January 2009. Further contributing to our decrease in revenues is the fact that our natural gas derivative contracts are being marked to market and they are included in "Gain on oil and gas derivative contracts" in the accompanying condensed consolidated statements of operations rather than revenues as previously reported when such contracts qualified for hedge accounting treatment.

Gross Profit. Gross profit in the second quarter of 2009 decreased $53.3 million as compared to the same period in 2008. This decrease was primarily due to reduced gross profit attributable to our Oil and Gas segment as a result of lower commodity prices realized, as described above.

Further, Contracting Services gross profit decreased 15% and its gross margin decreased by five points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects, a $6.8 million charge to revise our estimated loss associated with a contract that was terminated because of the delay in delivery of the Caesar (Note 18) and the stronger U.S. dollar affecting the translated gross margins of our international operations. Our Contracting Services gross margin benefitted from $1.9 million of insurance proceeds in excess of current period hurricane-related expenditures during the second quarter of 2009 (Note 5).

Shelf Contracting gross profit increased 14% primarily reflecting the increases in services as discussed in revenues above. The Shelf Contracting gross margins remained flat between the comparable second quarter periods.

The Oil and Gas gross profit decreased by 56% in the second quarter of 2009 as compared to the second quarter of 2008. This decrease reflects the significantly lower oil and natural gas prices realized on our sales volumes as well as decreases in our production. Our oil and gas gross profit in the second quarter of 2009 was also affected by insurance proceeds in excess of current period hurricane-related expenditures of $38.8 million (Note 5) and $11.5 million of impairment charges associated with the decreases in the proved reserve estimates of four fields at June 30, 2009.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $1.3 million during the three months ended June 30, 2009. In April 2008, we sold a 10% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron blocks 371 and 381) for a gain of $30.5 million. This gain was partially offset by an $11.9 million loss related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment.

Selling and Administrative Expenses. Selling and administrative expenses of $39.4 million for the second quarter of 2009 were $2.9 million lower than the $42.2 million incurred in the same prior year period. The decrease reflects the deconsolidation of Cal Dive following a reduction of our ownership interest on June 10, 2009, lower stock based compensation which totaled $3.1 million in the second quarter of 2009 compared to $4.8 million in the second quarter of 2008 (including $1.5 million of expense related to the separation agreement with our former Chief Financial Officer, Mr. Pursell, as a result of the termination of his employment with the Company), and the enactment of certain administrative cost saving measures. These decreases were partially offset by Cal Dive recording a $3.4 million allowance for bad debt expense in the second quarter period prior to its deconsolidation from our financial results.

Equity in Earnings of Investments. Equity in earnings of investments increased by $0.1 million during the three month period ended June 30, 2009 as compared to the same prior year period. Our equity in earnings for the three month period ended June 30, 2009 includes $0.9 million related to our approximate 26% ownership interest in Cal Dive that effective June 11, 2009 is accounted for under the equity method accounting. Our equity in earnings related to our 20% investment in Independence Hub increased $2.8 million over the same prior year period. Our equity in earnings from our 50% investment in Deepwater Gateway decreased by $5.7 million over same period in 2008, reflecting reduced throughput at the facility as a result of ongoing hurricane related repairs to infrastructure that have affected production from the fields surrounding the Marco Polo facilities.

Net Interest Expense and Other. We reported net interest and other expense of $7.5 million in the second quarter 2009 as compared to $20.6 million in the same prior year period. Gross interest expense of $27.6 million during the three months ended June 30, 2009 was lower than the $31.6 million incurred in 2008 reflecting lower interest rates and reduced levels of debt, including repayment of all amounts outstanding under our revolving credit facility and deconsolidation of Cal Dive's debt on June 10, 2009. Capitalized interest totaled $11.9 million in the second quarter of 2009 compared with $9.6 million of capitalized interest in the same prior year period. For the three month period ended June 30, 2009 we recorded $4.5 million of unrealized gains associated with mark to market adjustments related to our foreign exchange contracts.

Provision for Income Taxes. Income taxes were $56.8 million in the three months ended June 30, 2009 as compared to $54.8 million in the same prior year period. The increase was primarily due to increased profitability. The effective tax rate of 35.5% for the second quarter of 2009 was lower than the 36.2% rate for the second quarter of 2008. The effective tax rate for the second quarter of 2009 decreased as a result of the deconsolidation of CDI and not having any nondeductible goodwill as we did in the same prior year period. This decrease in the rate was partially offset by the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production.

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Comparison of Six Month Periods Ended June 30, 2009 and 2008

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 470,331	$ 392,661	$ 77,670
Shelf Contracting	404,709	316,541	88,168
Oil and Gas	250,173	365,212	(115,039)
Production Facilities	5,472	—	5,472
Intercompany elimination	(65,071)	(102,515)	37,444
	$1,065,614	$ 971,899	$ 93,715
Gross profit (in thousands) –			
Contracting Services	$ 87,293	$ 84,187	$ 3,106
Shelf Contracting	92,728	71,946	20,782
Oil and Gas	119,725	159,729	(40,004)
Production Facilities	(859)	—	(859)
Intercompany elimination	(1,921)	(8,201)	6,280
	$ 296,966	$ 307,661	$ (10,695)
Gross Margin –			
Contracting Services	19%	21%	(2 pts)
Shelf Contracting	23%	23%	—
Oil and Gas	48%	44%	4 pts
Total company	28%	32%	(4 pts)
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Offshore construction vessels	9/83%	8/95%	
Well operations	2/87%	2/43%	
ROVs	47/68%	42/66%	

(1) Represents number of vessels (including chartered vessels) as of the end of the period excluding acquired vessels prior to their in-service dates, and vessels taken out of service prior to their disposition.
(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 six month periods ended June 30, 2009 and 2008 were as follows (in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Increase/ (Decrease)
Contracting Services	$ 52,854	$ 84,894	$ (32,040)

Shelf Contracting (1)	7,865	17,621	(9,756)
Production Facilities	4,352	—	4,352
	$ 65,071	$ 102,515	$ (37,444)

(1) Excludes the 20 days from June 11, 2009 to June 30, 2009 following the deconsolidation of Cal Dive from our condensed consolidated financial statements.

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Intercompany segment profit during the six month periods ended June 30, 2009 and 2008 was as follows (in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Increase/ (Decrease)
Contracting Services	$ 1,447	$ 5,822	$ (4,375)
Shelf Contracting (1)	503	2,379	(1,876)
Production Facilities	(29)	—	(29)
	$ 1,921	$ 8,201	$ (6,280)

(1) Excludes the 20 days from June 11, 2009 to June 30, 2009 following the deconsolidation of Cal Dive from our condensed consolidated financial statements.

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	1,626	1,807	(181)
Oil sales revenue (in thousands)	$ 105,655	$ 174,045	$ (68,390)
Average oil sales price per Bbl (excluding hedges)	$ 60.00	$ 103.78	$ (43.78)
Average realized oil price per Bbl (including hedges)	$ 64.99	$ 96.33	$ (31.34)
Decrease in oil sales revenue due to:			
Change in prices (in thousands)	$ (56,622)		
Change in production volume (in thousands)	(11,768)		
Total decrease in oil sales revenue (in thousands)	$ (68,390)		
Gas production volume (MMcf)	14,525	19,594	(5,069)
Gas sales revenue (in thousands)	$ 69,168	$ 188,825	$ (119,657)
Average gas sales price per mcf (excluding hedges)	$ 4.23	$ 9.92	$ (5.69)
Average realized gas price per mcf (including hedges recorded as gas sales revenues)	$ 4.76	$ 9.64	$ (4.88)
Average realized gas price per mcf (including hedges recorded as revenues and gain on oil and gas derivative contracts)	$ 7.10	$ 9.64	$ (2.54)

Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$ (95,516)		
Change in production volume (in thousands)	(24,141)		
Total decrease in gas sales revenue (in thousands)	$(119,657)		
Total production (MMcfe)	24,279	30,435	(6,156)
Revenue price per Mcfe, including hedges	$ 7.20	$ 11.92	$ (4.72)
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 174,823	$362,870	$ (188,047)
Other revenues(1)	75,350	2,342	73,008
	$ 250,173	$365,212	$ (115,039)

(1) Other revenues included fees earned under our process handling agreements. The amount in 2009 also includes $73.5 million of previously accrued royalty payments involved in a legal dispute that were reversed in January 2009 following a favorable ruling by the Fifth District Court of Appeals, which rendered the probability of being required to make these payments remote (Note 8).

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

	Six Months Ended June 30,			
	2009		2008	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 36,467	$ 1.50	$ 46,295	$ 1.52
Workover (3)	1,695	0.07	6,706	0.22
Transportation	3,421	0.14	3,136	0.10
Repairs and maintenance	5,185	0.21	10,601	0.35
Overhead and company labor	4,361	0.18	3,796	0.13
Total	$ 51,129	$ 2.10	$ 70,534	$ 2.32
Depletion expense	$ 85,162	$ 3.51	$ 104,579	$ 3.44
Abandonment	1,531	0.06	3,477	0.11
Accretion expense	8,062	0.33	6,503	0.21
Impairment (4)	11,804	0.49	17,028	0.56
Net hurricane (reimbursements) costs (5)	(29,200)	(1.20)	-	-

(1) Excludes exploration expense of $2.0 million and $3.4 million for the six months ended June 30, 2009 and 2008, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Excludes all hurricane-related cost and charges resulting from Hurricane Ike in September 2008 (see (5) below).

(4) Amount for 2009 period reflects charge to reduce the carrying value of four fields to their estimated net realizable value following reductions in their estimated proved reserves at June 30, 2009.

(5) Represents the amount of net proceeds in excess of previously incurred costs and related impairment charges. For the six months ended June 30, 2009, we received a total of $100.9 million of insurance proceeds associated with our oil and gas operations which were offset by $20.2 million of related hurricane repair cost and impairment charges totaling $51.5 million, including $43.8 million to increase the asset retirement obligations associated with properties that were considered a total loss following Hurricane Ike in September 2008.

Revenues. Our revenues for the six month period ended June 30, 2009 increased by 9% as compared to the same period in 2008. Contracting Services revenues increased 20% primarily due to strong performance from our robotics subsidiary as well as significant increased revenues from our well operation vessels, including the Q4000, which was out of service most of the first half of 2008. Shelf Contracting revenues increased 28% primarily as a result of new international construction activities and increased demand for repair and salvage work following the hurricanes that affected the Gulf of Mexico in the third quarter of 2008 and higher vessel utilization. This increase was partially offset by having 20 less days in the second quarter 2009 period as a result of the deconsolidation of Cal Dive effect June 10, 2009 (see "Reduction of Cal Dive Ownership" above and Note 4).

Oil and Gas revenues decreased 32% during the six month period ended June 30, 2009 as compared to the same period in 2008. The decrease in oil revenues was attributable to a 33% decrease in realized oil prices with a 10% decrease in production compared with the same prior year period. Our production of both oil and natural gas continued to be affected by ongoing repairs to third party pipelines. Repairs to a key third party pipeline continue, which when completed would benefit our production as this particular pipeline provides service to our Noonan gas field, where production has been curtailed since it commenced production in January 2009. The decrease in gas revenues was attributable to a 51% decrease in realized gas prices and a 26% decrease in gas production. Further contributing to our decrease in revenues is the fact that a substantial portion of our natural gas derivative contracts for 2009 are being marked to market and are included in "Gain on oil and gas derivative contracts" in the

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accompanying condensed consolidated statements of operations rather than revenues as previously reported when such contracts qualified for hedge accounting treatment.

Our oil and gas revenues for the six month period ended June 30, 2009 benefitted from $73.5 million of previously accrued royalty payments that were in dispute. Following a favorable appellate judicial ruling we reversed these amounts as oil and gas revenues and have begun accounting for the additional oil and gas revenues associated with the previously disputed royalty net revenue interest and we are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

Gross Profit. Gross profit during the six months ended June 30, 2009 decreased $10.7 million as compared to the same period in 2008. This increase was primarily due to reduced gross profit attributable to our Oil and Gas segment as a result of lower commodity prices realized, as described above, offset partially by the $29.2 million of insurance reimbursement in excess of hurricane related costs in the first half of 2009 and a reduction in the comparison of non-hurricane related impairment charges which totaled $11.8 million in the first half of 2009 as compared to $17.0 million in first half of 2008, of which approximately $14.6 million was related to the unsuccessful development well in January 2008 on Devil's Island (Garden Banks 344).

In addition, Contracting Services gross profit increased 4% because of the factors stated above. However, Contracting Services gross margin decreased by two points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects, a $6.8 million charge to revise our estimated loss associated with a contract that was terminated because of the delay in delivery of the Caesar (Note 18) and the stronger U.S. dollar affecting the translated gross margins of our international operations.

The Shelf Contracting gross profit increased by 29% for the six month period ending June 30, 2009 as compared to the same period last year. This increase primarily reflects the higher revenues associated with the services discussed in revenues above. The Shelf Contracting gross margins remained flat between the comparable six month periods ending June 30, 2009 and 2008.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $1.8 million during the six month period ended June 30, 2009. For the six month period ended June 30, 2008, we recognized a gain of $91.6 million related to the sale of a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron blocks 371 and 381). Offsetting this gain was a loss of $11.9 million related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment.

Selling and Administrative Expenses. Selling and administrative expenses for the six month period ended June 30, 2009 were $7.7 million lower than the same prior year period. The decrease reflects the deconsolidation of Cal Dive following a reduction of our ownership interest on June 10, 2009, the recognition of approximately $6.9 million of expenses related to the separation agreements between the Company and two of our former executive officers, and the enactment of certain administrative cost saving measures. These decreases were partially offset by Cal Dive recording a $3.4 million allowance for bad debt expense in the second quarter period prior to its deconsolidation from our financial results.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $3.2 million during the six month period ended June 30, 2009 as compared to the same prior year period. This decrease was primarily due to an $8.9 million decrease in the equity in earnings of Deepwater Gateway in the comparable periods reflecting reduced throughput at the facility as a result of ongoing hurricane related repairs that have affected production from the fields surrounding the Marco Polo facilities. This decrease was offset in part by a $2.9 million increase in the earnings of our 20% investment in Independence Hub. Our equity in earnings for the three and six month periods ended June 30, 2009 includes $0.9 million related to our approximate 26% ownership interest in Cal Dive that effective June 11, 2009 is accounted for under the equity method accounting.

Net Interest Expense and Other. We reported net interest and other expense of $29.7 million for the first half of 2009 as compared to $48.6 million in the same prior year period. Gross interest expense of $57.5 million during the six month period ended June 30, 2009 was lower than the $68.4 million incurred in 2008 primarily reflecting lower interest rates and a reduction in our debt since year end 2008. Offsetting the decrease in interest expense were reductions to both capitalized interest and interest income, which totaled $19.5 million and $0.4 million, respectively in the first half of 2009, while capitalized interest was $20.6 million and interest income was $1.6 million in the first half of 2008. For the six month period ended June 30, 2009 we recorded $5.1 million of unrealized gains associated with mark to market adjustments related to our foreign exchange contracts.

Provision for Income Taxes. Income taxes were $121.7 million in the six months ended June 30, 2009 as compared to $97.5 million in the same prior year period. The increase was primarily due to increased profitability. The effective tax rate of 35.8% for the six month period ended June 30, 2009 was lower than the 36.4% rate for the same prior year period. The effective tax rate for the first six months of 2009 decreased as a result of the deconsolidation of CDI and not having any nondeductible goodwill as we did in the same prior year period. This decrease in the rate was partially offset by the reduced benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production.

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):

	June 30, 2009	December 31, 2008
Working capital	$ 170,240	$ 287,225
Long-term debt(1)	1,348,713	1,933,686

(1) Long-term debt does not include the current maturities portion of the long-term debt as such amount is included in net working capital. It is also net of unamortized debt discount that was recorded effective with the adoption of a new accounting standard (Notes 3 and 9).

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net cash provided by (used in):		
Operating activities	$ 422,872	$ 190,329
Investing activities	$ (107,845)	$ (317,547)
Financing activities	$ (275,779)	$ 60,367

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

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We are closely monitoring the ongoing volatility and uncertainty in the financial markets and continue our internal focus on improving our balance sheet by increasing our liquidity through reductions in planned capital spending and potential dispositions of our non-core business assets. We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant economically hedged portion (63%) of our estimated oil and gas production over the remainder of 2009 and into 2010. We believe that internally generated cash flow and available borrowing capacity under our existing Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months. In the first half of 2009, we repaid all remaining borrowings under our revolving credit facility, which totaled $349.5 million.

A continuing period of weak economic activity may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by the current economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral. We cannot assure you that we would have access to the credit markets as needed to replace our existing debt and we could incur increased costs associated with any available replacement financing.

In accordance with the Senior Unsecured Notes, Senior Credit Facilities, Convertible Senior Notes and the MARAD Debt, 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 June 30, 2009 and December 31, 2008, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

The Senior Unsecured Notes essentially prohibit any of our restricted subsidiaries from creating, issuing, incurring, assuming, guaranteeing or becoming directly or indirectly liable for the payment of any indebtedness unless specified otherwise in the indenture. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. Cal Dive and its subsidiaries never guaranteed our Senior Unsecured Notes. The Senior Unsecured Notes may be redeemed prior to the stated maturity under certain circumstances specified in the indenture governing the Senior Unsecured Notes.

Provisions of the amended Senior Credit Facilities 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 (such as our Senior Unsecured Notes), and also permit our subsidiaries to incur project financing indebtedness 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 first half of 2009, no conversion triggers were met.

As of June 30, 2009, we had $407.8 million of available borrowing capacity under our credit facilities.

Working Capital

Cash flow from operating activities increased by $232.5 million in the six months ended June 30, 2009 as compared to the same period in 2008. This increase includes the effect of recognizing $73.5 million of previously disputed cash royalty payments that we had been deferring until January 2009 (Note 6) and the increase in our working capital cash flows.

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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 six months ended June 30, 2009 and 2008 were as follows (in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Capital expenditures:		
Contracting Services	$(110,986)	$ (185,552)
Shelf Contracting	(39,569)	(40,875)
Production Facilities	(18,179)	(66,044)
Oil and Gas	(69,668)	(262,329)
Investments in equity investments	(454)	(708)
Distributions from equity investments, net(1)	3,253	9,118
Proceeds from sale of Cal Dive common stock, net of cash effect of deconsolidation of Cal Dive	83,661	
Proceeds from sale of Helix RDS	20,874	
Proceeds from sales of properties	23,238	229,243
Other	(15)	(400)
Cash used in investing activities	$(107,845)	$ (317,547)

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

Restricted Cash

As of June 30, 2009 and December 31, 2008, we had $35.4 million 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 South Marsh Island Block 130 acquisition in 2002 by our Oil and Gas segment. We had fully satisfied the escrow requirement as of June 30, 2009. We may use the restricted cash for the future decommissioning the related field.

Equity Investments

We received the following distributions from our equity investments during the six months ended June 30, 2009 and 2008 (in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Deepwater Gateway.	$ 3,500	$ 14,500

Independence	13,200	14,000
Total	$ 16,700	$ 28,500

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Sale of Oil and Gas Properties

In the first quarter of 2009 we sold our remaining 10% interests in the Bass Lite field for $4.5 million and our interests in East Cameron Block 316 for $18 million. We sold three fields in the second quarter of 2009 resulting in a gain of $1.2 million. In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008, including $30.5 million in the second quarter of 2008.

In May 2008, we sold all our interests in our Onshore Properties to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

Insurance Renewal

After considerable negotiations we renewed our energy and marine insurance for the period July 1, 2009 to June 30, 2010. However, this insurance renewal did not include wind storm coverage as premium and deductibles would have been relatively substantial for the underlying coverage provided. In order to mitigate potential loss to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a weather derivative (Catastrophic Bonds). The Catastrophic Bonds provide for payments of negotiated amounts should the eye of a Category 3 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The cost of these Catastrophic Bonds totaled approximately $13 million and the premium will be amortized over the next twelve months.

Outlook

We anticipate capital expenditures for the remainder of 2009 will range from $200 million to $250 million. We believe internally generated cash flow, and borrowings under our existing credit facilities will provide the funds necessary for our planned 2009 capital expenditures.

The following table summarizes our contractual cash obligations as of June 30, 2009 and the scheduled years in which the obligations are contractually due (in thousands):

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	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000
Senior Unsecured Notes	550,000				550,000
Term Loan	416,929	4,326	8,652	403,951	
MARAD debt	121,368	4,318	9,293	10,244	97,513
Revolving Credit Facility					
Loan notes	5,086	5,086			
Interest related to long-term debt	608,511	82,128	158,449	146,354	221,580
Preferred stock dividends(3)	1,000	1,000			
Drilling and development costs	74,676	74,676			
Property and equipment(4)	8,200	8,200			
Operating leases(5)	130,152	60,304	62,887	5,635	1,326
Total cash obligations	$2,215,922	$240,038	$239,281	$566,184	$1,170,419

(1) Excludes unsecured letters of credit outstanding at June 30, 2009 totaling $12.2 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At June 30, 2009, the conversion trigger was not met. In December 2012, the Convertible Senior Notes are subject to early redemption options at option of each the holders of the Convertible Senior Notes and by us (see Note 11 of our 2008 Form 10-K).

(3) Amount represents dividend payment for one year only. Dividends are paid quarterly until such time the holder elects to convert the stock. In July 2009, the holder of the preferred stock elected to convert 60% of its remaining shares into common stock. Accordingly, the remaining annual dividend will now approximate $0.4 million.

(4) Costs incurred as of June 30, 2009 and additional property and equipment commitments (excluding capitalized interest) at June 30, 2009 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Estimated Project Cost Range
Caesar conversion	$ 168,000	$ 2,700	$ 210,000-230,000
Well Enhancer construction	195,000	4,500	200,000-220,000
Helix Producer I(a)	220,000	1,000	340,000-360,000
Total	$ 583,000	$ 8,200	$ 750,000-810,000

(a)

Represents 100% of the cost of the vessel, conversion and construction of additional facilities, of which we expect our portion to range between $278 million and $298 million.

(5) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at June 30, 2009 were approximately $116.9 million.

Contingencies

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were 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 royalty on certain federal leases up to certain specified production volumes. Our oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded 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 Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable. We appealed this order on the same basis as the previous orders.

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Other operators in the Deep Water 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, including ours. 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 filed a notice of appeal of that decision on December 21, 2007. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. The plaintiff petitioned the appellate court for rehearing; however, that petition was denied on April 14, 2009. The plaintiff has petitioned the United States Supreme Court for a writ of certiorari for the Supreme Court to review the Firth Circuit Court's decision. There is no certainty that the Supreme Court will accept the case.

As a result of this dispute, we had been recording reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006, 2007 and 2008) plus interest at 5% for our portion of the Gunnison related MMS claim. Following the decision of the United States Court of Appeals for the Fifth Circuit Court, we reversed our previously accrued royalties ($73.5 million) as oil and gas revenue in our first quarter 2009 results. Effective in January 2009, we commenced recognizing oil and natural gas sales revenue associated with this previously disputed net revenue interest and we are no longer accruing any additional royalty reserves as we believe it is remote that we will be liable for such amounts.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 "Accounting for Performance of Construction-Type and Certain Production-Type Contracts". Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract that was completed in May 2009, our loss was $0.8 million, all of which was provided with our estimated loss accrual at December 31, 2008. Under a second contract, which was terminated, we have a potential future liability of up to $25 million. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed and we revised our estimated loss to approximately $15.8 million. To reflect this additional estimated loss we recorded an additional $6.8 million charge to cost of sales in the accompanying condensed consolidated statement of operations. We have paid $7.2 million of the $15.8 million of estimated damages related to this terminated contact. We will continue to monitor our exposure under this contract until the job and all related disputes have been finalized.

In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. As there are substantial defenses to this claimed breach, we cannot at this time determine if we have any r exposure under the contract. Over the remainder of 2009, we will continue to assess our potential exposure to damages under this contract as the circumstances warrant. Under the terms of the contract, our potential liability is generally capped for actual damages at approximately $27 million Australian dollars ("AUS") (approximately $21.8 million US dollars at June 30, 2009) and for liquidated damages at approximately $5 million AUS (approximately $4.0 million US dollars at June 30, 2009). At June 30, 2009, we have an $8.8 million AUS (approximately $7.1 million US dollars at June 30, 2009) claim against our counterparty for work performed prior to the termination of the contract. We continue to pursue payment for this work.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements. We prepare these financial statements in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Please read the following discussion in conjunction with our "Critical Accounting Policies and Estimates" as disclosed in our 2008 Form 10-K.

NEW ACCOUNTING STANDARDS

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. We adopted SFAS No. 160 on January 1, 2009, which is required to be adopted prospectively, except the following provisions must be adopted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recasting consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Effective January 1, 2009, we changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with SFAS No. 160, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in CDI. Our ownership of CDI following the transaction approximated 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale was treated as a reduction of our equity in the accompanying condensed consolidated balance sheet (Note 18). Any future significant transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will be recognized in our statement of operations.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 requires entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows or financial condition. See Note 17 below for additional disclosure regarding our derivative instruments.

In May 2008, the FASB issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). We adopted the FSP APB 14-1 effective January 1, 2009. FSP APB 14-1 requires retrospective application for all periods reported (with the cumulative effect of the change reported in

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retained earnings as of the beginning of the first period presented). FSP APB 14-1 requires 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 is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This FSP changed the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 increases our interest expense for our past and future reporting periods by recognizing accretion charges on the resulting debt discount.

Upon adoption of FSP APB 14-1, we recorded a discount of $60.2 million related to our Convertible Senior Notes. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012).

The following table sets forth the effect of retrospective application of FSP APB 14-1 and FSP EITF 03-06-1 "Determining Whether Instruments Granted in Share Based Payment Transactions Are Participating Securities." (Note 12) on certain previously reported line items in our accompanying condensed consolidated statements of operations (in thousands, except per share data):

	Three Months Ended June 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 18,668	$ 20,615
Provision for Income taxes	55,925	54,773
Net income from continuing operations	98,858	96,402
Earnings per common share from continuing operations - Basic	$ 1.00	$ 0.97
Earnings per common share from continuing operations – Diluted	0.96	0.92

	Six Months Ended June 30, 2008	
	Originally Reported	As Adjusted
Net interest expense and other	$ 44,714	$ 48,616
Provision for Income taxes	99,557	97,473
Net income from continuing operations	174,311	170,045
Earnings per common share from continuing operations - Basic	$ 1.83	$ 1.75
Earnings per common share from continuing operations – Diluted	1.75	1.68

On June 30, 2009, we adopted FASB Staff Position (FSP) No. FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, (FSP FAS 157-4). FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with SFAS 157 when the volume and level of activity for the asset or liability have significantly decreased and includes guidance for identifying circumstances that indicate a transaction is not orderly. This guidance is necessary to maintain the overall objective of fair value measurements, which is that fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. The adoption of FSP FAS 157-4 had no impact on our results of operations, cash flows and financial condition.

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On June 30, 2009, we adopted Statement of Financial Accounting Standards No. 165, Subsequent Events (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, SFAS 165 sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of SFAS 165 had no impact on the our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

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.

Foreign Currency Exchange Risk. In order to mitigate our exposure to fluctuations in the currencies under which some of our foreign operations are conducted, we hedged a portion of our future estimated costs. As of June 30, 2009, we had placed foreign exchange contracts fixing the exchange rate of approximately 33.5 million pounds (GBP) for approximately $51.0 million US dollars. These contracts are for periods from July 2009 through June 2012.

Commodity Price Risk. As of June 30, 2009, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,100 MBbl of oil and 34.7 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
July 2009 — December 2009	Forward Sales(2)	150 MBbl	$71.79
January 2010 — December 2010	Collar(1)	100 MBbl	$62.50-$80.73
Natural Gas:			(per Mcf)
July 2009 — December 2009	Collar(3)	558.3 Mmcf	$7.00 — $7.90
July 2009 — December 2009	Forward Sales(4)	1,387.6 Mmcf	$8.23
January 2010 — December 2010	Swap(1)	912.5 Mmcf	$5.80
January 2010 — December 2010	Collar(1)	1,003.8 Mmcf	$6.00 — $6.70

(1) Designated as cash flow hedges, still deemed effective and qualifies for hedge accounting.
(2) Qualified for scope exemption as normal purchase and sale contract.
(3) Designated as cash flow hedges, deemed ineffective and are now being mark-to-market through earnings each period.
(4) No long qualify for normal purchase and sale exemption and are now being marked-to-market through earnings each period.

Subsequent to June 30, 2009 and through August 5, 2009, we entered into three cash flow hedging swap agreements. The first contract covers 150 MBbl total at a price of $73.05 per barrel for the period from January to December 2010. The second contract covers 60 MBbl total at a price of $71.82 per barrel for the period from January to June 2010. The third contract covers 90 MBbl total at a price of $74.07 per barrel for the period July to December 2010.

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Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended June 30, 2009. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended June 30, 2009 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. We completed the implementation of our enterprise resource planning system, as previously reported, on January 1, 2009. We have continued to evolve our controls accordingly. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended June 30, 2009.

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 1A. Risk Factors

The risk factor below updates our risk factors previously reported in our annual report on Form 10-K for the year ended December 31, 2008 to specifically reference recent legislative and regulatory proposals:

Potential legislation and/or regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. Changes to existing laws and regulations or new laws and regulations may unfavorably impact us, our suppliers and/or our customers. For example, governments around the world have become increasingly focused on climate change matters. In the United States, legislation that directly impacts our industry has been proposed covering areas such as emission reporting and reductions, the repeal of certain oil and gas tax incentives and tax deductions, and the regulation of over-the-counter commodity hedging activities. A federal agency has issued proposed modifications to its prior rulings regarding the application of the Jones Act to the carriage by foreign flag vessels of items relating to certain offshore activities on the Outer Continental Shelf ("OCS"). If adopted, this revised ruling could potentially lead to operational delays or increased operating costs in instances where we would be required to hire coastwise qualified vessels that we currently do not own, in order to transport certain merchandise to projects on the OCS. This could increase our costs of compliance and doing business and make it more difficult to perform pipelay or well operation services. These and other potential regulations could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum number of shares that may yet be purchased under the program
April 1 to April 30, 2009(1)	61	$ 8.57		$ N/A
May 1 to May 31, 2009(1)	114	10.54		N/A
June 1 to June 30, 2009(1) (2)	46,587	9.89	42,500	1,457,500
	46,762	$ 9.89	42,500	$ 1,457,500

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

(2) In June 2009, we announced that we intend to purchase 1.5 million shares of our common stock as permitted under or principal credit facility (Note 15).

Item 4. Other Information

Helix's Annual Meeting of Shareholders was held on May 13, 2009. As of the close of business on March 19, 2009, the record date for the annual meeting, there were 98,387,639 shares of common stock entitled to vote, of which there were 78,749,953 (80.04%) shares present at the annual meeting in person or by proxy. At the annual meeting, stockholders voted on one matter: the election of three Class II Directors for a term of three years expiring at the 2012 Annual Meeting of Shareholders. The voting results were as follows:

T. William Porter	For	66,547,249	Withheld	12,202,704
William L. Transier	For	61,662,112	Withheld	17,087,841
James A. Watt	For	68,256,939	Withheld	10,493,014

The three nominees for Class II Director were elected.

Our Class I Directors Owen Kratz, Bernard J. Duroc-Danner and John V. Lovoi, continue in office until our 2010 Annual Meeting of Shareholders. Our Class III Directors, Gordon F. Ahalt and Nancy K. Quinn continue in office until our 2011 Annual Meeting of Shareholders.

Item 6. Exhibits

3.1 2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.

3.2

	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
10.1	Stock Repurchase Agreement between Company and Cal Dive International, Inc., dated May 29, 2009 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on June 1, 2009.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter(1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer(1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer(1)
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes – Oxley Act of 2002(2)
99.1	Report of Independent Registered Public Accounting Firm(1)
	(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: August 5, 2009	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: August 5, 2009	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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