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

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2010

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

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

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

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

Yes [√] No [ ]

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

Yes [√] No [ ]

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

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

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

Yes [ ] No [√]

As of October 26, 2010,105,455,523 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	September 30, 2010	December 31, 2009
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 325,480	$ 270,673
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $4,419 and $5,172, respectively	176,396	145,519
Unbilled revenue	17,712	17,854
Costs in excess of billing	24,113	9,305
Other current assets	125,575	122,209
Total current assets	669,276	565,560
Property and equipment	4,494,387	4,352,109
Less — accumulated depreciation	(1,863,609)	(1,488,403)
	2,630,778	2,863,706
Other assets:		
Equity investments	187,112	189,411
Goodwill	79,093	78,643
Other assets, net	79,000	82,213
	$ 3,645,259	$ 3,779,533
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 165,484	$ 155,457
Accrued liabilities	197,966	200,607
Current maturities of long-term debt	10,845	12,424
Total current liabilities	374,295	368,488
Long-term debt	1,346,698	1,348,315
Deferred income taxes	398,649	442,607
Asset retirement obligations	163,372	182,399
Other long-term liabilities	7,569	4,262
Total liabilities	2,290,583	2,346,071
Convertible preferred stock	1,000	6,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,450 and 104,281 shares issued, respectively	905,880	907,691
Retained earnings	442,526	519,807
Accumulated other comprehensive loss	(18,984)	(22,241)
Total controlling interest shareholders' equity	1,329,422	1,405,257
Noncontrolling interests	24,254	22,205
Total equity	1,353,676	1,427,462
	$ 3,645,259	$ 3,779,533

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

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009
Net revenues:		
Contracting services	$ 297,103	$ 152,310
Oil and gas	95,566	63,715
	392,669	216,025
Cost of sales:		
Contracting services	211,634	127,402
Oil and gas	93,586	84,469
Oil and gas property impairments	897	1,537
	306,117	213,408
Gross profit	86,552	2,617
Gain on oil and gas derivative contracts	161	4,598
Gain on sale or acquisition of assets, net	13	—
Selling and administrative expenses	(26,628)	(21,884)
Income (loss) from operations	60,098	(14,669)
Equity in earnings of investments	6,221	13,385
Gain on sale of Cal Dive common stock	—	17,901
Net interest expense	(25,479)	(7,250)
Other income (expense)	4,072	(3,056)
Income before income taxes	44,912	6,311
Provision for income taxes	17,965	4,468
Income from continuing operations	26,947	1,843
Discontinued operations, net of tax	—	3,021
Net income, including noncontrolling interests	26,947	4,864
Less: net income applicable to noncontrolling interests	(776)	(844)
Net income applicable to Helix	26,171	4,020
Preferred stock dividends	(10)	(125)
Net income applicable to Helix common shareholders	$ 26,161	$ 3,895
Basic earnings per share of common stock:		
Continuing operations	$ 0.25	$ 0.01
Discontinued operations	—	0.03
Net income per common share	$ 0.25	$ 0.04
Diluted earnings per share of common stock:		
Continuing operations	$ 0.25	$ 0.01
Discontinued operations	—	0.03
Net income per common share	$ 0.25	$ 0.04
Weighted average common shares outstanding:		
Basic	104,090	101,282
Diluted	105,307	101,334

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

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net revenues:		
Contracting services	$ 604,634	$ 967,751
Oil and gas	288,867	313,888
	893,501	1,281,639
Cost of sales:		
Contracting services	438,008	765,602
Oil and gas	266,032	151,844
Oil and gas property impairments	171,871	64,610
	875,911	982,056
Gross profit	17,590	299,583
Gain on oil and gas derivative contracts	2,643	83,328
Gain on sale or acquisition of assets, net	6,246	1,773
Selling and administrative expenses	(91,675)	(102,609)
Income (loss) from operations	(65,196)	282,075
Equity in earnings of investments	12,932	27,152
Gain on sale of Cal Dive common stock	—	77,343
Net interest expense	(61,637)	(44,860)
Other income (expense)	(3,145)	4,891
Income (loss) before income taxes	(117,046)	346,601
Provision (benefit) for income taxes	(41,962)	126,196
Income (loss) from continuing operations	(75,084)	220,405
Discontinued operations, net of tax	(44)	10,303
Net income (loss), including noncontrolling interests	(75,128)	230,708
Less: net income applicable to noncontrolling interests	(2,049)	(19,017)
Net income (loss) applicable to Helix	(77,177)	211,691
Preferred stock dividends	(104)	(688)
Preferred stock beneficial conversion charges	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ (77,281)	$ 157,564
Basic earnings (loss) per share of common stock:		
Continuing operations	$ (0.74)	$ 1.49
Discontinued operations	—	0.10
Net income (loss) per common share	$ (0.74)	$ 1.59
Diluted earnings (loss) per share of common stock:		
Continuing operations	$ (0.74)	$ 1.38
Discontinued operations	—	0.10
Net income (loss) per common share	$ (0.74)	$ 1.48
Weighted average common shares outstanding:		
Basic	103,772	97,831
Diluted	103,772	105,868

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

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash flows from operating activities:		
Net income (loss), including noncontrolling interests	$ (75,128)	$ 230,708
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	222,730	208,870
Asset impairment charge and dry hole expense	171,626	64,610
Equity in earnings of investments, net of distributions	—	(222)
Amortization of deferred financing costs	5,731	4,095
Loss (income) from discontinued operations	44	(10,303)
Stock compensation expense	6,889	9,435
Amortization of debt discount	6,272	5,878
Deferred income taxes	(53,335)	(53,012)
Excess tax benefit from stock-based compensation	2,376	2,036
Gain on sale or acquisition of assets	(6,246)	(1,773)
Unrealized (gain) loss on derivative contracts	2,304	(19,785)
Gain on sale of investment in Cal Dive common stock		(77,343)
Changes in operating assets and liabilities:		
Accounts receivable, net	(29,256)	7,215
Other current assets	3,947	33,483
Income tax payable	4,896	157,931
Accounts payable and accrued liabilities	38,662	(46,213)
Asset retirement obligation costs	(52,244)	(16,042)
Other noncurrent, net	(7,458)	(62,307)
Cash provided by operating activities	241,810	437,261
Cash used in discontinued operations	(44)	(6,089)
Net cash provided by operating activities	241,766	431,172
Cash flows from investing activities:		
Capital expenditures	(179,018)	(306,152)
Investments in equity investments	—	(551)
Distributions from equity investments, net	2,108	4,774
Insurance recovery for capital items	16,106	—
Proceeds from sale of Cal Dive common stock	—	418,168
Reduction in cash from deconsolidation of Cal Dive	—	(112,995)
Proceeds from sales of property	852	23,238
Other	(133)	(13)
Net cash (used in) provided by investing activities	(160,085)	26,469
Cash provided by discontinued operations	—	20,872
Net cash (used in) provided by investing activities	(160,085)	47,341

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash flows from financing activities:		
Repayment of Helix Term Loan	$ (3,245)	$ (3,245)
Repayments on Helix Revolver	—	(349,500)
Repayment of MARAD borrowings	(4,866)	(4,214)
Borrowings on CDI Revolver	—	100,000
Repayments on CDI Term Note	—	(20,000)
Deferred financing costs	(2,864)	(50)
Repurchases of common stock	(11,659)	(10,603)
Excess tax benefit from stock-based compensation	(2,376)	(2,036)
Loan note repayment, preferred stock dividends paid and other	(1,611)	(589)
Net cash used in financing activities	(26,621)	(290,237)
Effect of exchange rate changes on cash and cash equivalents	(253)	(1,383)
Net increase in cash and cash equivalents	54,807	186,893
Cash and cash equivalents:		
Balance, beginning of year	270,673	223,613
Balance, end of period	$ 325,480	$ 410,506

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

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

Note 1 – Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its majority-owned subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its majority-owned subsidiaries. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI") was a majority-owned subsidiary of Helix. Helix sold substantially all its ownership interest in Cal Dive during 2009 (see Note 4 below and Note 3 of our Annual Report on Form 10-K for the year ended December 31, 2009 ("2009 Form 10-K")). All material intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission ("SEC"), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and are consistent in all material respects with those applied in our 2009 Form 10-K. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations, and cash flows, as applicable. The operating results for the periods ended September 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010. Our balance sheet as of December 31, 2009 included herein has been derived from the audited balance sheet as of December 31, 2009 included in our 2009 Form 10-K. These unaudited condensed consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and notes thereto included in our 2009 Form 10-K.

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

Note 2 – Company Overview

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

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into three disciplines: subsea construction, well operations and production facilities. We have disaggregated our contracting services operations into two continuing reportable segments: Contracting Services and Production Facilities. Our Contracting Services business primarily consists of subsea construction, well operations activities and robotics. Formerly, we had a third Contracting Services segment, Shelf Contracting, which represented the assets of CDI. We sold substantially all of our ownership of CDI through various transactions in 2009 (Note 4). Our Production Facilities business includes our equity investments (Note 8) in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") as well as our majority ownership of the *Helix Producer I* ("*HP I*") vessel.

Oil and Gas Operations

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 generate incremental returns. Over time, we 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

In April 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 included in our Contracting Services segment.

Business Strategy

Over the past two years, we have focused on improving our balance sheet by increasing our liquidity through reductions in planned capital spending as well as dispositions of our non-core business assets. Since the beginning of 2009, dispositions of non-core business assets resulted in the receipt of the following pre-tax proceeds:

- Sold six oil and gas properties for approximately $25 million;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009;
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees, in June 2009 and September 2009 (for additional information regarding the sales of CDI common shares by us see Note 4); and
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009.

In March 2010, we announced that we had engaged advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. At the time of the filing of this Quarterly Report on Form 10-Q, we do not have an approved or definitive plan for the disposition of our oil and gas business.

Recent Events in Gulf of Mexico

Oil Spill

On April 20, 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252. The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S territorial waters. After months of coordinated containment efforts, the operator of the Macondo project, BP PLC ("BP"), controlled the flow of the oil and permanently plugged the well. As previously disclosed, three of our vessels, the *Q4000*, the *Express* and the *HP I,* participated in the coordinated containment response to the oil spill in the Gulf of Mexico. All three vessels were released by BP in October.

Drilling Moratorium

On May 12, 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. This moratorium also affected 33 in progress deepwater wells. On May 28, 2010 the moratorium on drilling in the shallow water of the Gulf, defined as water depths less than 500 feet, was lifted. However, the DOI extended the drilling moratorium on deepwater wells through November 2010. On October 12, 2010, the DOI lifted the drilling moratorium on deepwater wells and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") that it could resume issuing drilling permits subject to a company's compliance with all revised drilling, safety and environmental requirements. No deepwater drilling permits have been issued since the lifting of the drilling moratorium and relatively few shallow water drilling permits have been issued since its ban was lifted in May 2010.

New Reclamation Requirements

On September 15, 2010, BOEMRE issued Notice to Lessees (NTL) 2010-G05 with an effective date of October 15, 2010. The NTL continues the previously mandated timeframe for decommissioning structures (platforms and pipelines) and wells on terminated leases, which requires the lessee to commence reclamation activities within 12 months following the termination of any federal lease. The new requirements of the NTL mandate that leaseholders of active oil and gas leases submit plans to abandon wells and structures that have been inactive over the past five years. These types of structures are commonly referred to as “idle iron” within the industry. Pursuant to the new regulations, operators of properties with idle iron must submit plans to BOEMRE that address the removal of dormant structures within the next five years and dormant wells over the next three years. This new mandate may have the effect of accelerating the timing of certain reclamation activities at some of our oil and gas fields. We are evaluating the potential impact of this NTL on our oil and gas properties and expect to complete this assessment by year-end 2010.

As noted above, the most significant potential impact of these new requirements is the acceleration of certain oil and gas reclamation activities. In situations where this could ultimately apply, the acceleration would serve to increase a field’s recorded abandonment liability by reducing the discount effect on the liability. The effect of this change on the existing asset retirement obligation would either be recorded as an increase to a field’s property, plant and equipment value if the field continues to have operations (this increase would impact that property’s depletion rate on a prospective basis) or as an immediate operating charge in our statement of operations for properties that have no current operations, although such cases should be rare.

Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in thousands)	
Other receivables	$ 3,665	$ 7,990
Prepaid insurance	20,937	11,105
Other prepaids	11,784	21,819
Inventory	25,294	25,755
Current deferred tax assets	31,171	24,517
Hedging assets	17,648	6,214
Gas imbalance	6,650	7,655
Income tax receivable	2,489	8,492
Other	5,937	8,662
	$ 125,575	$ 122,209

Other assets, net, consisted of the following as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in thousands)	
Restricted cash	$ 35,277	$ 35,409
Deferred drydock expenses, net	12,836	12,030
Deferred financing costs	27,489	30,061
Intangible assets with finite lives, net	729	768
Other	2,669	3,945
	$ 79,000	$ 82,213

Accrued liabilities consisted of the following as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in thousands)	
Accrued payroll and related benefits	$ 32,053	$ 30,513
Royalties payable	7,530	5,717
Asset retirement obligations	77,346	65,729
Unearned revenue	3,055	3,672
Accrued interest	15,732	27,830
Billing in excess of cost	4,939	—
Deposit	25,542	25,542
Hedge liability	11,196	19,536
Other	20,573	22,068
	$ 197,966	$ 200,607

Note 4 — Ownership of Cal Dive International, Inc.

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 have resulted 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 June 2009, we sold 22.6 million shares of Cal Dive common stock held by us pursuant to a secondary public offering ("Offering") and Cal Dive repurchased an additional 1.6 million shares of its common stock from us. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, and subsequently accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 2009, when we sold substantially all of our remaining interest in Cal Dive.

See Note 3 of our 2009 Form 10-K for additional information regarding our sale transactions involving Cal Dive common stock in 2009.

We continue to own 0.5 million shares of Cal Dive common stock (cost basis of $5.1 million), representing less than 1% of the total outstanding shares of Cal Dive. Accordingly, we now classify our remaining interest in Cal Dive as an investment available for sale. As an investment available for sale, the value of our remaining interest will be marked-to-market at each period end with the corresponding change in value being reported as a component of accumulated other comprehensive income (loss) in the accompanying condensed consolidated balance sheets (Note 11). The pre-tax value of our remaining investment in Cal Dive as of September 30, 2010 has decreased $1.0 million since December 31, 2009 and $2.3 million since our Cal Dive sales transaction in September 2009. At September 30, 2010, we considered our unrealized loss on our remaining Cal Dive investment to be temporary. On October 15, 2010, Cal Dive announced that its third-quarter 2010 results will include impairment charges, including some if not all of its recorded goodwill. In light of this potential development, we will again evaluate our position regarding the status of our unrealized loss on our Cal Dive investment in the fourth quarter of 2010 after reviewing the filing of Cal Dive's Quarterly Report on Form 10-Q for the period ending September 30, 2010. Should we determine that these losses are not temporary at that time or at any other time in the future we will remove the unrealized amounts from our accumulated other comprehensive loss by recording the difference between our original investment and the then expected realizable value as a non operating expense charge in our consolidated statement of operations. Once an other than temporary loss has been recorded, future changes in the fair value of the investment will again be recorded as a component of other accumulated comprehensive income (loss) until such time the investment is ultimately sold or a subsequent "other than temporary loss" is deemed to have occurred.

Note 5 – Convertible Preferred Stock

In January 2009, Fletcher International, Ltd. (“Fletcher”) issued a redemption notice with respect to its $30 million of Series A-2 Cumulative Convertible Preferred Stock and, pursuant to the resulting 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 in our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares delivered in connection with the redemption over the original 1,964,058 shares that would have been contractually required to be issued upon a 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 in June 2004.

In February 2009, the price of our common stock fell below $2.767 per share. Under the terms of the agreement governing the issuance of the cumulative convertible preferred stock, we provided notice to Fletcher that with respect to the $25 million of Series A-1 Cumulative Convertible Preferred Stock the conversion price was reset to $2.767, the established minimum price per the agreement; that Fletcher shall have no further rights to redeem the shares; and that 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 Credit Agreement (Note 9) we are not permitted to deliver cash 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. The beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock was limited to the $24.1 million of net proceeds received upon its issuance in January 2003.

In May 2010, Fletcher converted $5 million of its Series A-1 Cumulative Convertible Preferred Stock into 1,807,011 shares of our common stock. In the third quarter of 2009, Fletcher converted $19 million of its Series A-1 Cumulative Convertible Preferred Stock into 6,866,641 shares of our common stock. The remaining $1 million of the Series A-1 Cumulative Convertible Preferred Stock, which is convertible into 361,402 shares of our common stock, maintains its mezzanine presentation below liabilities but is not included as a component of shareholders’ equity, because we may, under certain instances be required to settle any future conversions in cash. Prior to any future conversion(s), the common shares issuable will be assessed for inclusion 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 all periods in which we have positive earnings from continuing operations and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the 361,402 shares will be included in our diluted shares outstanding amount.

Note 6 – Oil and Gas Properties

In March 2010, we announced that we engaged advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. At the time of the filing of this Quarterly Report on Form 10-Q, we do not have an approved or definitive plan for the disposition of our oil and gas business.

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

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

Mid-Year 2010 Reserve Assessment

In connection with our regular mid-year review as well as our efforts to pursue potential divestment alternatives for our oil and gas business, we engaged an independent petroleum reservoir engineering firm to update our estimates of proved reserves for our domestic oil and gas properties as of June 30, 2010. The resulting independent petroleum engineer reserve report indicated the we had a significant reduction in proved reserves resulting from a combination of factors including well performance issues at certain of our producing fields, most notably our Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our other oil and gas properties. The changes in field economics primarily affected properties that were either close to the end of their production life or in which we had proved undeveloped reserves, which would have been required to be developed in the near term. The decision not to develop these properties in light of these economic changes was also driven by our desire to pursue potential alternatives to divest our oil and gas business and the increasing uncertainties about future regulation of oil and gas operations in the Gulf of Mexico as a result of the oil spill from the Macondo well. As a result of the reduction in estimated reserves we were required to record oil and gas property impairment charges (see below).

Impairments

Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. In the third quarter of 2010 we recorded a $0.9 million impairment charge associated with a revised estimated asset reclamation obligation for one non-producing field that is scheduled to be abandoned in 2011.

In the first quarter of 2010, we recorded $7.0 million of impairment charges primarily resulting from the decline in natural gas prices during the first quarter of 2010. The three properties subject to these impairment charges produce natural gas almost entirely. Separately, we also recorded a $4.1 million impairment charge for our only non-domestic oil and gas property (see “United Kingdom Property” below).

In the second quarter of 2009, we recorded an aggregate of approximately $63.1 million of impairment charges. These charges primarily reflected the approximate $51.5 million of impairment-related charges recorded to properties that were severely damaged by Hurricane Ike (as discussed below in Insurance). 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. We recorded an aggregate $1.5 million of additional impairment charges associated with five fields following a comprehensive impairment analysis at September 30, 2009.

Exploration and Other

As of September 30, 2010, we capitalized approximately $3.2 million of costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

The following table details the components of exploration expense for the three and nine-month periods ended September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Delay rental and geological and geophysical costs	$ 497	$ 755	$ 2,025	$ 2,288
Dry hole expense	(55)	149	(245)	575
Total exploration expense	$ 442	$ 904	$ 1,780	$ 2,863

Royalty Claims

We and other industry participants were involved in a dispute with the U.S. Department of the Interior Minerals Management Service ("MMS"), or now known as BOEMRE, over royalties associated with production from certain deepwater oil and gas leases. As a result of this dispute, we recorded 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 the MMS claim, which affected our Garden Banks Blocks 667, 668 and 669 ("Gunnison") leases. The result of accruing these reserves since 2005 reduced our oil and gas revenues. In the first quarter of 2009, following the decision of the United States Court of Appeals for the Fifth Circuit Court affirming the district court's previous ruling in favor of the plaintiffs in that case, which pertained to the Gunnison leases, we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues. On October 5, 2009, the United States Supreme Court denied the government's petition for a writ of certiorari, and the MMS subsequently withdrew its orders to pay the royalty.

For additional information regarding our royalty dispute and related litigation see Note 17 of our 2009 Form 10-K.

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. In 2007, we sold half of our 100% working interest in Camelot to a third party with whom we agreed to jointly pursue future development and production of the field. In February 2010, we acquired this third party thereby assuming its obligations, most notably the asset retirement obligation ("ARO"), related to its 50% working interest in the field. The following table contains the fair value of the assets acquired and liabilities assumed in our acquisition of this third party and its 50% working interest in the Camelot field (in thousands):

Cash	$ 10,156
Deferred tax asset	2,083
Accrued liabilities	(439)
Asset retirement obligation	(5,841)
Gain on acquisition of assets	$ 5,959

In connection with the valuation of assets acquired and liabilities assumed in this acquisition, we reassessed the fair value associated with our original 50% interest in the field. Based on these evaluations, it was concluded that an impairment of the property was required based on the unlikely probability of our spending the future capital necessary to further develop the Camelot field and our plans are to abandon the field over the near term. As a result, we recorded a $4.1 million impairment charge to fully impair the property.

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 of 2009, we sold three fields for gross proceeds of $0.8 million resulting in an aggregate gain of $1.2 million, including transfer of the respective field's asset retirement obligations.

Asset retirement obligations

The following table describes the changes in our asset retirement obligations (both long term and current) since December 31, 2009 (in thousands):

Asset retirement obligation at December 31, 2009	$ 248,128
Liability incurred during the period [a]	18,056
Liability settled during the period	(47,580)
Revision in estimated cash flows	10,428
Accretion expense (included in depreciation and amortization)	11,686
Asset retirement obligations at September 30, 2010	$ 240,718

a) Amount primarily includes the acquisition of the remaining 50% working interest in the Camelot field in February 2010 (see "United Kingdom Property" above) and the additional scope of work associated with the development of the Phoenix field. Initial production was deferred from June 2010 to allow our *HP I* vessel to be contracted and used in the Gulf oil spill containment efforts. Following its release from the oil spill containment response contract, the *HP I* mobilized to the Phoenix field, where initial production commenced on October 19, 2010.

Insurance

In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricanes *Gustav* and *Ike*. While we sustained some damage to our own production facilities from Hurricane *Ike*, the larger issue in terms of production recovery involved damage to third party pipelines and onshore processing facilities. We carried comprehensive insurance on all of our operated and non-operated producing and non-producing properties. We record our hurricane-related costs as incurred. Insurance reimbursements were recorded 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 damage 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 resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a "total loss" following the storm. During the nine-month period ending September 30, 2010, we incurred a total of $4.6 million of additional hurricane-related repair costs, including $0.9 million in the third quarter of 2010.

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 settled under our energy insurance policy in June 2009 (in thousands):

	Third Quarter 2009	Nine Months Ended September 30, 2009
Oil and gas:		
Hurricane repair costs	$ 5,060	$ 25,223
ARO liability adjustments	—	43,812
Hurricane-related impairments	—	7,699
Insurance recoveries	—	(100,874)
Net (reimbursements) costs	5,060	(24,140)
Contracting services:		
Hurricane repair costs	—	776
Insurance recoveries	(159)	(2,885)
Net (reimbursements) costs	(159)	(2,109)
Shelf Contracting:		
Hurricane repair costs	3	613
Insurance recoveries	(238)	(2,849)
Net (reimbursements) costs	(235)	(2,236)
Totals:		
Hurricane repair costs	5,063	26,612
ARO liability adjustments	—	43,812
Hurricane-related impairments	—	7,699
Insurance recoveries	(397)	(106,608)
Net (reimbursements) costs	$ 4,666	$ (28,485)

Similar as in 2009, our 2010 insurance renewal did not include wind storm coverage as the premium and deductibles would have been relatively substantial for the coverage provided. Our insurance year runs from July 1 to June 30. In order to mitigate potential loss with respect to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we entered into a Catastrophic Bond instrument. The Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 2 or greater hurricane pass within certain pre-defined areas encompassing our more prominent oil and gas producing fields. The amount paid for this Catastrophic Bond in 2010 was approximately $11.9 million. The Catastrophic Bond is not considered a risk management instrument for accounting purposes. Accordingly, the premium associated with the Catastrophic Bond is not charged to expense on a straight line basis as customary with insurance premiums, but rather it is charged to expense on a basis to reflect the Catastrophic Bond's intrinsic value at the end of the period. Because our Catastrophic Bond was underwritten to mitigate the risk of hurricanes in the Gulf of Mexico, substantially all of its intrinsic value is for the period associated with "hurricane season" (typically June 1 to November 30) with a substantial majority of the intrinsic value associated with the period July 1, 2010 to September 30, 2010. As a result, we charged $9.4 million of the $11.9 million payment to expense in the third quarter of 2010 and will charge $2.3 million of the premium to expense in the fourth quarter of 2010. The remaining $0.2 million will be charged to expense over the first half of 2011. The expense associated with the Catastrophic Bond payment is recorded as a component of lease operating expense for our oil and gas operations.

Note 7 – Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. We had restricted cash totaling $35.3 million at September 30, 2010 and $35.4 million December 31, 2009 all of which was related to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement and may use the restricted cash for asset retirement costs incurred at the related field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

The following table provides supplemental cash flow information for the nine months ended September 30, 2010 and 2009 (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Interest paid, net of capitalized interest (1)	$ 60,137	$ 51,696
Income taxes paid	$ 8,020	$ 57,412

Non-cash investing activities for the nine-month periods ended September 30, 2010 and 2009 included $17.5 million and $63.6 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 8 – Equity Investments

As of September 30, 2010, 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 $100.7 million and $103.3 million as of September 30, 2010 and December 31, 2009, respectively (including capitalized interest of $1.5 million at September 30, 2010 and December 31, 2009). Distributions from Deepwater Gateway, net to our interest, totaled $2.3 million and $6.1 million for the respective three-month and nine-month periods ended September 30, 2010.

- *Independence Hub, LLC.* In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. First production through the facility commenced in July 2007. Our investment in Independence Hub was $83.5 million and $86.1 million as of September 30, 2010 and December 31, 2009, respectively (including capitalized interest of $5.3 million and $5.6 million at September 30, 2010 and December 31, 2009, respectively). Distributions from Independence Hub, net to our interest, totaled $5.7 million and $16.4 million for the three-month and nine-month periods ended September 30, 2010, respectively.

The following presents selected summarized unaudited operating results for our Deepwater Gateway and Independence Hub equity investments for the three and nine-month periods ended September 30, 2010 and 2009 (in thousands):

	Deepwater Gateway		Independence Hub		Combined	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2010	2009	2010	2009	2010	2009
Revenues	$ 4,343	$ 3,896	$ 24,500	$ 30,639	$ 28,843	$ 34,535
Operating income	2,240	1,854	20,927	27,062	23,167	28,916
Net income	2,241	1,855	20,929	27,066	23,170	28,921
Equity in earnings	$ 1,120	$ 928	$ 4,186	$ 5,413	$ 5,306	$ 6,341

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	Deepwater Gateway		Independence Hub		Combined	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009	2010	2009
Revenues	$ 13,085	$ 12,229	$ 81,265	$ 97,410	$ 94,350	$ 109,639
Operating income	6,824	5,008	70,545	86,677	77,369	91,685
Net income	6,826	5,022	70,548	86,698	77,374	91,720
Equity in earnings	$ 3,413	$ 2,511	$ 14,110	$ 17,340	$ 17,523	$ 19,851

In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company, Clough Projects Australia Pty Ltd ("Clough"), to provide a range of subsea services to offshore operators in the Asia Pacific region. Services provided by the joint venture, named CloughHelix JV Co., will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving, and subsea inspection, repair and maintenance services. The CloughHelix JV will integrate our well intervention equipment with Clough's new 12 man saturation diving system, to enable both to be deployed from the 118 meter long DP2 multiservice vessel, the *Normand Clough*, outfitted with a 250 ton active heave compensated crane. We recorded $0.7 million of income and $5.0 million of losses associated with our 50% interest in the joint venture for the three-month and nine-month periods ended September 30, 2010, respectively. The losses for the nine-month period primarily represented the mobilization costs of transporting the *Normand Clough* from the Gulf of Mexico to Singapore and other start up costs related to the joint venture. This joint venture is part of our Contracting Services segment.

Note 9 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of September 30, 2010 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes (1)	MARAD Debt	Other(2)	Total
Less than one year	$ 4,326	$ —	$ —	$ —	$ 4,645	$ 1,874	$ 10,845
One to two years	4,326	—	—	—	4,877	—	9,203
Two to three years	402,870	—	—	—	5,120	—	407,990
Three to four years	—	—	—	—	5,376	—	5,376
Four to five years	—	—	—	—	5,644	—	5,644
Over five years	—	—	550,000	300,000	89,149	—	939,149
Total debt	411,522	—	550,000	300,000	114,811	1,874	1,378,207
Current maturities	(4,326)	—	—	—	(4,645)	(1,874)	(10,845)
Long-term debt, less current maturities	$ 407,196	$ —	$ 550,000	$ 300,000	$ 110,166	$ —	$ 1,367,362
Unamortized debt discount (3)	—	—	—	(20,664)	—	—	(20,664)
Long-term debt	$ 407,196	$ —	$ 550,000	$ 279,336	$ 110,166	$ —	$ 1,346,698

(1) Beginning in December 2012, the holders may require us to repurchase the notes or we may at our own option elect to repurchase notes. If the notes are redeemed in December 2012, the amount payable in two to three years in the table above increases to approximately $708 million. The Notes do not contractually mature until March 2025.
(2) Represents the balance of the loan provided by Kommandor RØMØ to Kommandor LLC as of September 30, 2010.
(3) Reflects debt discount resulting from adoption of provisions of ASC Topic No. 470-20 "*Convertible Debt and Other Options*" on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

At September 30, 2010, unsecured letters of credit issued totaled approximately $61.2 million (see "Credit Agreement" below). These letters of credit primarily guarantee various contract bidding, contractual performance, including asset retirement obligations, and insurance activities. The following table details our interest expense and capitalized interest for the three and nine-month periods ended September 30, 2010 and 2009:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Interest expense	$ 25,784	$ 23,582	$ 74,730	$ 81,094
Interest income	(263)	(282)	(660)	(694)
Capitalized interest	(42)	(16,050)	(12,433)	(35,540)
Interest expense, net	$ 25,479	$ 7,250	$ 61,637	$ 44,860

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt see Note 10 of our 2009 Form 10-K.

Senior Unsecured Notes

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

Credit Agreement

In July 2006, we entered into a credit agreement (the “Credit Agreement”) under which we borrowed $835 million in a term loan (the “Term Loan”) and were initially able to borrow up to $300 million (the “Revolving Loans”) under a revolving credit facility (the “Revolving Credit Facility”). The parties have amended the Credit Agreement three times, most recently in February 2010, to address certain issues with regard to covenants, maturity and the borrowing limits under the Revolving Credit Facility. For additional information regarding the current terms of our credit facility see Note 9 of our Quarterly Report on Form 10-Q for the period ending March 31, 2010.

The proceeds from the Term Loan were used to fund the cash portion of the acquisition of Remington Oil and Gas Corporation in July 2006. The Term Loan currently bears interest either at the one-, three- or six-month LIBOR at our election plus a margin of between 2.25% and 2.5% depending on current leverage ratios. Our average interest rate on the Term Loan for the nine-month periods ended September 30, 2010 and 2009 was approximately 2.9% and 4.8%, respectively, including the effects of our interest rate swaps (Note 18). The Term Loan is scheduled to mature on July 1, 2013.

The original maturity date of the Revolving Credit Facility was July 1, 2011. In the fourth quarter of 2009, we increased the Revolving Credit Facility and extended its maturity date to November 30, 2012. As a consequence of the foregoing, the borrowing limit under the Revolving Credit Facility was increased by amendment to $435 million, effective December 31, 2009. This amount will decrease to $410 million beginning July 1, 2011 and will stay at that level through the maturity of the Revolving Credit Facility on November 30, 2012. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At September 30, 2010, we had no amounts drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $373.8 million, net of $61.2 million of letters of credit issued.

The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our election plus an applicable margin. The margin ranges from 1.0% to 4.5%, depending on our consolidated leverage ratio. We did not have any borrowings under our Revolving Loans in the nine months ended September 30, 2010. Our average interest rate on the Revolving Loans through their repayment date in the second quarter of 2009 was approximately 3.4%.

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

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan (Note 18).

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. No conversion triggers were met during the nine-month period ended September 30, 2010. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012. The effective interest rate for the Convertible Senior Notes is 6.6%.

Our average share price for all the periods presented in this Quarterly Report on Form 10-Q was below the $32.14 per share conversion price. As a result of our share price being lower than the $32.14 per share conversion price for these periods there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is 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* vessel. The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures approximately 25 years from such date. The MARAD Debt is collateralized by the *Q4000,* with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027).

Other

In accordance with our Credit Agreement and our Senior Unsecured Notes, Convertible Senior Notes and 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. The Senior Unsecured Notes and Credit Agreement contain provisions that limit our ability to incur certain types of additional indebtedness. As of September 30, 2010, we were in compliance with all of our debt covenants and restrictions.

Deferred financing costs of $27.5 million at September 30, 2010 and $30.1 million at December 31, 2009 are included in other assets, net and are being amortized over the life of the respective loan agreements, which is included as interest expense in the accompanying condensed consolidated statements of operations.

Note 10 – Income Taxes

We recorded an income tax provision with an effective tax rate of 40.0% for the three-month period ended September 30, 2010. For the nine-month period ended September 30, 2010 we recorded an income tax benefit with an effective tax rate of 35.9%. We recorded a tax provision with an effective tax rate of 70.8% and 36.4% for the three-month and nine-month periods ended September 30, 2009, respectively. The more favorable effective tax rate for the nine months ended September 30, 2010 is due to the deconsolidation of CDI in 2009.

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 11 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three and nine-month periods ended September 30, 2010 and 2009 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss), including noncontrolling interests	$ 26,947	$ 4,864	$ (75,128)	$ 230,708
Other comprehensive income (loss), net of tax				
Foreign currency translation gain (loss)	5,436	(3,343)	(8,372)	23,689
Unrealized gain (loss) on hedges, net	(3,795)	(2,883)	12,308	(16,221)
Unrealized loss on investment available for sale	(123)	(130)	(679)	(130)
Total Comprehensive income (loss)	28,465	(1,492)	(71,871)	238,046
Less: Comprehensive loss applicable to noncontrolling interest	–	(844)	–	(19,590)
Total other comprehensive income (loss) applicable to Helix	$ 28,465	$ (2,336)	$ (71,871)	$ 218,456

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

	September 30, 2010	December 31, 2009
Cumulative foreign currency translation adjustment	$ (20,324)	$ (11,952)
Unrealized gain (loss) on hedges, net	2,906	(9,402)
Unrealized loss on investment available for sale	(1,566)	(887)
Accumulated other comprehensive loss	$ (18,984)	$ (22,241)

Note 12 – Earnings Per Share

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

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The presentation of EPS amounts on the face of the accompanying consolidated statements of operations is segregated between amounts related to continuing operations, discontinued operations and total earnings per share as is appropriate. Basic 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 computations of the numerator (Income) and denominator (Shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying consolidated statements of operations are as follows (in thousands):

	Three Months Ended September 30, 2010		Three Months Ended September 30, 2009	
	Income	**Shares**	**Income**	**Shares**
Basic:				
Net income (loss) applicable to common shareholders	$ 26,161		$ 3,895	
Less: Undistributed net income allocable to participating securities	(356)		(53)	
Undistributed net income (loss) applicable to common shareholders	25,805		3,842	
(Income) loss from discontinued operations	—		(3,021)	
Add: Undistributed net income from discontinued operations allocable to participating securities	—		41	
Income (loss) per common share – continuing operations	$ 25,805	104,090	$ 862	101,282

	Three Months Ended September 30, 2010		Three Months Ended September 30, 2009	
	Income	**Shares**	**Income**	**Shares**
Diluted:				
Net income (loss) per common share – continuing operations – Basic	$ 25,805	104,090	$ 862	101,282
Effect of dilutive securities:				
Stock options	—	22	—	52
Undistributed earnings reallocated to participating securities	5	—	—	—
Convertible Senior Notes	—	—	—	—
Convertible preferred stock	—	1,195	—	—
Income (loss) per common share — continuing operations	25,810		862	—
Income (loss) per common share — discontinued operations	—		3,021	—
Net income (loss) per common share	$ 25,810	105,307	$ 3,883	101,334

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009	
	Income	**Shares**	**Income**	**Shares**
Basic:				
Net income (loss) applicable to common shareholders	$ (77,281)		$ 157,564	
Less: Undistributed net income allocable to participating securities	—		(2,284)	
Undistributed net income (loss) applicable to common shareholders	(77,281)		155,280	
(Income) loss from discontinued operations	44		(10,303)	
Add: Undiscounted net income from discontinued operations allocable to participating securities	—		149	
Income (loss) per common share – continuing operations	$ (77,237)	103,772	$ 145,126	97,831

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009	
	Income	Shares	Income	Shares
Diluted:				
Net income (loss) per common share – continuing operations – Basic	$ (77,237)	103,772	$ 145,126	97,831
Effect of dilutive securities:				
Stock options	—	—	—	3
Undistributed earnings reallocated to participating securities	—	—	160	—
Convertible Senior Notes	—	—	—	—
Convertible preferred stock	—	—	688	8,034
Income (loss) per common share — continuing operations	(77,237)		145,974	
Income (loss) per common share — discontinued operations	(44)		10,303	
Net income (loss) per common share	$ (77,281)	103,772	$ 156,277	105,868

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

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

There were no dilutive stock options for the nine-month period ended September 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 transactions affecting our convertible preferred stock (Note 5) are not included as an addition to adjust earnings applicable to common stock for our diluted earnings per share calculation. The diluted EPS amount included the $0.1 million and $0.7 million of dividends and related costs associated with the assumed conversion of the convertible preferred stock for the three and nine-month periods ended September 30, 2009.

Note 13 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the “1995 Incentive Plan”) and the 2005 Long-Term Incentive Plan, as amended (the “2005 Incentive Plan”). As of September 30, 2010, there were approximately 1.3 million shares available for grant under our 2005 Incentive Plan.

During the nine-month period ended September 30, 2010, 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:

Date of Grant	Type	Shares	Market Value Per Share	Vesting Period
January 4, 2010	(1)	452,849	$ 11.75	20% per year over five years
January 4, 2010	(2)	23,569	11.75	20% per year over five years
January 4, 2010	(1)	1,197	11.75	100% on January 1, 2012
April 1, 2010	(1)	4,029	13.03	100% on January 1, 2012

July 1, 2010	(1)	5,107	10.77	100% on January 1, 2012

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three and nine-month periods ended September 30, 2010 and 2009.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. There was no compensation cost associated with stock options for the three and nine-month periods ended September 30, 2010 as all outstanding stock options have vested. We recorded $0.1 million of compensation expense related to the final vesting of stock options in the first quarter of 2009. For the three and nine-month periods ended September 30, 2010, $2.1 million and $6.7 million, respectively, was recognized as compensation expense related to restricted shares as compared with $2.2 million and $6.8 million during the three and nine-month periods ended September 30, 2009, respectively.

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the “2009 LTI Plan”) to provide long term cash based compensation to eligible employees. Under the terms of the 2009 LTI Plan, the majority of the cash awards that have been issued under the 2009 LTI Plan are fixed sum amounts payable ratably over a five year vesting period. However, some of the cash awards that have been issued under the 2009 LTI Plan, also vesting over a five year period, are indexed to our Company common stock price and the payment amount will fluctuate based on the common stock’s performance. This share based component is considered a liability plan and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as appropriate.

The total awards made under the 2009 LTI Plan totaled $14.7 million in 2009, including $8.1 million for our executive officers. In January 2010, $10.1 million was awarded under the 2009 LTI Plan to eligible employees, including $6.0 million to our executive officers and other members of senior management. Total compensation under the 2009 LTI plan totaled $0.8 million and $3.4 million for the three and nine-month periods ended September 30, 2010, respectively. For the three and nine-month periods ended September 30, 2009, total compensation under the 2009 LTI plan totaled $0.7 million and $2.1 million, respectively.

For more information regarding our stock-based compensation plans, including our 2009 LTI Plan see Note 13 of our 2009 Form 10-K.

Note 14 – Business Segment Information

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two continuing reportable segments: Contracting Services and Production Facilities. As a result, our reportable segments consisted of the following: Contracting Services, Oil and Gas, and Production Facilities. Contracting Services operations include subsea construction, well operations and robotics. Formerly, we had a third contracting services business, Shelf Contracting, which consisted of CDI’s operations, and which included all assets deployed primarily for diving-related activities and shallow water construction. On June 10, 2009, we ceased consolidating CDI when our ownership interest decreased to below 50% following the sale of a portion of CDI common stock held by us (Note 4). We continued 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. For our Production Facilities segment, we account for our investments in Deepwater Gateway and Independence Hub under the equity method and we consolidate our investment in the *HP I*.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenues —				
Contracting Services	$ 238,531	$ 175,091	$ 595,048	$ 645,422
Shelf Contracting	–	–	–	404,709
Oil and Gas (1)	95,566	63,715	288,867	313,888
Production Facilities(2)	74,458	1,141	97,169	2,261
Intercompany elimination	(15,886)	(23,922)	(87,583)	(84,641)
Total	$ 392,669	$ 216,025	$ 893,501	$1,281,639
Income (loss) from operations —				
Contracting Services	$ 31,015	$ 22,199	$ 102,282	$ 96,583
Shelf Contracting	–	–	–	59,077
Oil and Gas (1)	(4,384)	(21,442)	(159,991)	166,686
Production Facilities (2)	44,520	(1,388)	57,460	(2,540)
Corporate (3)	(10,767)	(12,067)	(46,242)	(33,839)
Intercompany elimination	(286)	(1,971)	(18,705)	(3,892)
Total	$ 60,098	$ (14,669)	$ (65,196)	$ 282,075
Equity in earnings of equity investments	$ 6,221	$ 13,385	$ 12,932	$ 27,152

(1) Included $73.5 million of disputed accrued royalty payments that we reversed in first quarter of 2009 following a favorable court ruling (Note 6).
(2) Included the operating results related to the *HP I*.
(3) Included $13.8 million of $17.5 million settlement of a third party claim against us in March 2010 (Note 16).

Intercompany segment revenues during the three and nine-month periods ended September 30, 2010 and 2009 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Contracting Services	$ 15,886	$ 23,922	$ 84,053	$ 76,776
Shelf Contracting	–	–	–	7,865
Production Facilities	–	–	3,530	–
Total	$ 15,886	$ 23,922	$ 87,583	$ 84,641

Intercompany segment gross profit (losses) during the three and nine-month periods ended September 30, 2010 and 2009 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Contracting Services	$ 330	$ 2,153	$ 15,473	$ 3,600
Shelf Contracting	–	(138)	–	365
Production Facilities	(44)	(44)	3,249	(73)
Total	$ 286	$ 1,971	$ 18,722	$ 3,892

Our identifiable assets as of September 30, 2010 and December 31, 2009 were as follows:

	September 30, 2010	December 31, 2009
	(in thousands)	
Identifiable Assets —		
Contracting Services	$ 1,860,370	$ 1,738,883
Oil and Gas	1,267,342	1,541,153
Production Facilities	517,547	499,497
Total	$ 3,645,259	$ 3,779,533

Note 15 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect. 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 80.4% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees. Production began in December 2003. Our payments to OKCD totaled $2.7 million and $8.7 million for the three and nine-month periods ended September 30, 2010, respectively, and $3.0 million and $8.4 million in the three and nine-month periods ended September 30, 2009, respectively.

Note 16 – Commitments and Contingencies

Commitments

Since September 30, 2009, we have added three vessels to our fleet. The *Well Enhancer* joined our well operations fleet in October 2009, and the *Caesar,* a pipelay vessel and the *HP I,* a floating production unit vessel were placed in service in the first half of 2010. These three vessels have represented a substantial amount of our capital expenditures since 2007. Although all three vessels are in service, a certain amount of future capital will be required to be spent to fully complete the vessels. For example, in the third quarter of 2010, the *Well Enhancer* went into port to commence the installation of a coiled tubing unit. This project has subsequently been completed and she returned to service in October. We currently estimate that we will spend up to an additional $35 million for future capital upgrades to these vessels. The estimate of these capital upgrades is subject to change depending upon market factors and/or the timing of when the work is ultimately performed. The timing of the capital upgrades is mainly determined by the vessel's utilization as we attempt to coordinate such activities with known gaps in its contractual backlog or when the vessel is scheduled for a regulatory inspection and/or drydocking. We currently anticipate that certain capital upgrades will be performed on the *Caesar* commencing in the fourth quarter of 2010.

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.

We are currently involved in a large project located offshore China in which we were contracted to abandon a number of wells utilizing our repaired subsea intervention device ("SID"), which was out of service since early 2009. Even though we anticipated that abandonment of the wells would be challenging, the work has proven somewhat more difficult than initially contemplated both from a structural standpoint and because of certain start up issues related to the repaired SID. Further complicating the project is the fact that typhoon season is in effect and we have lost a number of days due to weather. We now estimate that this job will no longer be profitable. In accordance with ASC No. 605-35 "*Construction Type and Production Type Contracts*" we have estimated the shortfall between the future revenues and future costs associated with the project. The current estimate of the loss on this

contract is $8.5 million, which was recorded in our results of operation for the three-month period ended September 30, 2010. This estimate is subject to change pending actual completion of the project which is expected to occur in the fourth quarter of 2010.

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

Litigation and Claims

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. Under the terms of the contract, our potential liability for damages was generally capped at approximately $32 million Australian dollars ("AUD"). We asserted a counterclaim that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. On April 19, 2010, pursuant to the terms of the settlement, we paid the third party $15 million AUD to settle all of its damage claims against us. We also agreed not to seek any further payment of our counter claims against them. In the first quarter of 2010, we recorded approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. These amounts were recorded as general and administrative expenses in the accompanying condensed consolidated statements of operations.

In 2008, we were subcontracted by the prime contractor to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2008 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivable and claims yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor then arbitration in India remains a potential remedy. Based on number of factors associated with the ongoing negotiations with the prime contractor, at September 30, 2010, we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable. However, at the time of this filing no commercial resolution of this matter has been reached and we are continuing to actively pursue collection of the full balance of our trade receivable and our other claims.

See Note 6 for information involving certain disputed royalty payments, which were recognized as oil and gas revenues in the first quarter of 2009.

Note 17 – Fair Value Measurements and Recent Accounting Standards

Fair Value Measurements

We follow the provisions of the ASC 820, *Fair Value Measurements and Disclosures,* for financial assets and liabilities that are measured and reported at fair value on a recurring basis. ASC 820 establishes a hierarchy for inputs used in measuring fair value. The fair value is to be calculated based on assumptions that market participants would use in pricing assets and liabilities and not on assumptions specific to the entity. The statement requires that each asset and liability carried at fair value be classified into one of the following categories:

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

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

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at September 30, 2010 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	$ –	$ 17,737	$ –	$ 17,737	(c)
Investment in Cal Dive	2,735	–	–	2,735	(a)
Foreign currency forwards	–	487	–	487	(c)
Liabilities:					
Oil and gas swaps and collars	–	10,996	–	10,996	(c)
Fair value of long term debt(2)	1,243,806	130,885	–	1,374,691	(a), (b)
Foreign currency forwards	–	612	–	612	(c)
Interest rate swaps	–	2,294	–	2,294	(c)
Total net liability	$ 1,241,071	$ 126,563	$ –	$ 1,367,634	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to use published future market prices and estimate market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences can be positive or negative.

(2) See Note 9 for additional information regarding our long term debt. The fair value of our debt at September 30, 2010 is as follows:

	Fair Value	Carrying Value
Term Loan (matures July 2013)	$ 395,061	$ 411,522
Revolving Credit Facility (matures November 2012)	–	–
Convertible Senior Notes (matures March 2025)	280,371	279,336
Senior Unsecured Notes (matures January 2016)	566,500	550,000
MARAD Debt (matures August 2027) (a)	130,885	114,811
Loan Note(b)	1,874	1,874
Total	$1,374,691	$1,357,543

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

(b) The carrying value of the Loan Note approximates fair value as the maturity date is current.

We account for long-lived assets in accordance with ASC 360-10-35, *Impairment of Disposal of Long-Lived Assets*, and review long-lived assets for impairment whenever events occur or changes in circumstances indicate that the carrying amount of assets may not be recoverable. In such evaluation, the estimated future undiscounted cash flows to be generated by the asset are compared with the carrying value of the asset to determine if an impairment may be required. For our oil and gas properties, the estimated future undiscounted cash flows are based on estimated crude oil and natural gas proved and probable reserves and published future market commodity prices, estimated operating costs and estimates of future capital expenditures. If the estimated undiscounted cash flows for a particular asset are not sufficient to cover the carrying value of the asset the asset is impaired and its carrying value is reduced to the current fair value. The fair value of these assets is determined using an income approach by calculating present value of future cash flows attributable to the asset based on market information (such as forward commodity prices), estimates of future costs and estimated proved and probable reserve quantities. These fair value measurements fall within Level 3 of the fair value hierarchy.

At June 30, 2010 we impaired 15 of our Gulf of Mexico properties as a result of reductions in estimates of proved reserves. The total amount of these impairment charges was $159.9 million, which reduced the carrying value of these properties to their aggregate fair value of $62.5 million. In the first quarter of 2010, we impaired three of our natural gas producing properties following a significant drop in natural gas prices during the period. The total amount of the impairment charges was $7.0 million, which reduced these properties to their aggregate fair value of $28.2 million.

We recorded a total $64.7 million of impairment charges in the second and third quarter of 2009. Prior to these impairment charges, the aggregate net book value of the affected fields was $68.9 million. The impairment charges reduced the fields to their then aggregate net fair value of $4.2 million. The substantial majority of the impairments were associated with fields to which we had to increase our reclamation obligation estimates.

See Note 6 for additional information regarding our oil and gas property impairment charges.

Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standard Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2010-06, “*Improving Disclosures about Fair Value Measurements*” an amendment to ASC Topic 820. This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reason for the transfers and (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements. This amendment is effective for interim and annual reporting periods beginning after December 15, 2009. We adopted this ASU effective January 1, 2010.

Note 18 – 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.

For additional information regarding our accounting for derivatives see Notes 2 and 22 of our 2009 Form 10-K.

Commodity Price Risks

We currently manage commodity price risks through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production for 2010. In the past, we have also utilized forward sales contracts that require physical delivery of oil and natural gas. We seek hedge accounting treatment for our oil and gas commodity derivative contracts. However, due to disruptions in our production as a result of damage caused by the hurricanes in third quarter 2008, most of our financial commodity contracts in place at March 31, 2009 no longer qualified for hedge accounting. Our forward sales contracts were not within the scope of derivative accounting as they qualified for the normal purchases and sales scope exception. However, due to disruptions in our production as a result of damage caused by the hurricanes, as mentioned above, they no longer qualified for the scope exception. As a result, both our oil and natural gas commodity contracts and our natural gas normal purchase and sale contracts were required to be marked-to-market effective March 31, 2009. Changes in the fair value of these mark-to-market oil and gas derivative contracts are reflected in our accompanying condensed consolidated statements of operations in the line titled "Gain on oil and gas derivative contracts."

Until June 2010 all of our oil and gas commodity contracts for expected 2010 production qualified for hedge accounting. In June 2010 some of our oil contracts for 480 MBbl covering portions of our anticipated production during the third quarter of 2010 ceased to qualify for hedge accounting as a result of our decision to contract the *HP I* to BP to assist in the Macondo well oil spill containment response rather than commencing production from our Phoenix field. In September 2010, we concluded that oil contracts covering 480 MBbls of the fourth quarter 2010 anticipated production ceased to qualify for hedge accounting because of uncertainty as to when the Phoenix field would be ready to commence initial production following extensions of the *HP I* contract to assist BP in the oil spill containment response. The *HP I* returned to the Phoenix field in October and initial production from the field commenced on October 19, 2010. All of our remaining commodity derivative contracts are designated as cash flow hedges and remain effective and qualify for hedge accounting as of September 30, 2010. The amount of ineffectiveness related to our oil and gas commodity contracts was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

As of September 30, 2010, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 3.3 MMBbl of oil and 14.2 Bcf of natural gas:

Production Period	Instrument Type	Approximate Average Monthly Volumes		Weighted Average Price
Crude Oil:				(per barrel)
October 2010 — December 2010	Collar	100	MBbl	$62.50-$80.73
October 2010 — December 2010	Swap	105	MBbl	$76.55
October 2010 — December 2010	Swap	107	MBbl	$81.39
January 2011 — December 2011	Swap	198	MBbl	$81.31
Natural Gas:				(per Mcf)
October 2010 — December 2010	Swap	1,020	Mmcf	$5.81
October 2010 — December 2010	Collar	1,012	Mmcf	$6.00 — $6.70
January 2011 — December 2011	Swap	675	Mmcf	$5.09

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

Variable Interest Rate Risks

As some of our long-term debt has variable interest rates and is subject to market influences, in January 2010 we entered into various interest rate swaps to stabilize cash flows relating to interest payments for $200 million of our Term Loan debt under our Credit Agreement (Note 9). These monthly contracts will mature in January 2012. 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”. Ineffectiveness related to our interest swaps was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

Foreign Currency Exchange Risks

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

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of September 30, 2010 and December 31, 2009. 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 17).

Derivatives designated as hedging instruments under ASC Topic No. 815:

	As of September 30, 2010		**As of December 31, 2009**	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
		(in thousands)		
Asset Derivatives:				
Oil contracts	Other current assets	$ —	Other current assets	$ —
Natural gas contracts	Other current assets	17,309	Other current assets	5,071
Natural gas contracts	Other assets, net	428	Other assets, net	—
Interest rate swaps	Other assets, net	—	Other assets, net	—
		$ 17,737		$ 5,071

	As of September 30, 2010		**As of December 31, 2009**	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
		(in thousands)		
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 8,737	Accrued liabilities	$ 19,477
Natural gas contracts	Accrued liabilities	—	Accrued liabilities	59
Interest rate swaps	Accrued liabilities	1,822	Accrued liabilities	—
Oil contracts	Other liabilities	2,118	Other liabilities	—
Natural gas contracts	Other liabilities	116	Other liabilities	—
Interest rate swaps	Other liabilities	472	Other liabilities	—

	$ 13,265	$ 19,536

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

	As of September 30, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
	(in thousands)			
Asset Derivatives:				
Natural gas contracts	Other current assets	$ —	Other current assets	$ —
Oil contracts	Other current assets	—	Other current assets	—
Foreign exchange forwards	Other current assets	339	Other current assets	1,143
Foreign exchange forwards	Other assets, net	148	Other assets, net	931
		$ 487		$ 2,074
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 25	Accrued liabilities	$ —
Foreign exchange forwards	Accrued liabilities	612	Accrued liabilities	—
Foreign exchange forwards	Other liabilities	—	Other liabilities	—
		$ 637		$ —

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated other comprehensive loss and our condensed consolidated statements of operations for the three and nine-month periods ended September 30, 2010 and 2009.

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010(1)	2009	2010(1)	2009
	(in thousands)			
Oil and natural gas commodity contracts	$ (3,405)	$ (3,140)	$ 13,799	$ (17,517)
Foreign exchange forwards	—	17	—	(539)
Interest rate swaps	(390)	240	(1,491)	1,835
	$ (3,795)	$ (2,883)	$ 12,308	$ (16,221)

(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 interest swaps, for which we have open contracts that have maturities through January 2012.

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Oil and natural gas commodity contracts	Oil and gas revenue	$ 7,428	$ 925	$ 17,892	$ 16,786
Interest rate swaps	Net interest expense and other	(468)	(369)	(1,355)	(1,654)
		$ 6,960	$ 556	$ 16,537	$ 15,132

The following table presents the impact of derivative instruments that no longer qualify for hedge accounting or were not designated as hedges on our condensed consolidated statement of operations for the three and nine-month periods ended September 30, 2010 and 2009:

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
		(in thousands)			
Natural gas contracts	Gain on oil and gas derivative contracts	$ 161	$ 4,598	$ 2,643	$ 83,328
Foreign exchange forwards	Net interest expense and other	1,106	(1,862)	(2,398)	3,281
Interest rate swaps	Net interest expense and other	—	(173)	—	(468)
		$ 1,267	$ 2,563	$ 245	$ 86,141

Note 19 – Share Repurchase Program

In June 2009, we announced that we intended to purchase up to 1.5 million shares plus an amount equal to additional shares of our common stock granted under our stock-based compensation plans (Note 13) of our common stock as permitted under our Credit Agreement (Note 9). 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. In early July 2010, we purchased the remaining 223,487 shares currently available under this plan for $2.5 million or an average of $11.21 per share. As of September 30, 2010, we had repurchased a total of 1,976,318 shares of our common stock for $24.0 million or an average of $12.16 per share. We retire all repurchased shares.

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 the 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 guaranty arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries relate 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)
(Unaudited)

	As of September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 303,787	$ 3,853	$ 17,840	$ —	$ 325,480
Accounts receivable, net	62,681	68,429	45,286	—	176,396
Unbilled revenue	14,961	—	26,864	—	41,825
Income taxes receivable	3,697	—	—	(1,208)	2,489
Other current assets	68,904	51,229	17,282	(14,329)	123,086
Total current assets	454,030	123,511	107,272	(15,537)	669,276
Intercompany	44,233	191,526	(156,827)	(78,932)	—
Property and equipment, net	249,704	1,674,563	711,617	(5,106)	2,630,778
Other assets:					
Equity investments	2,047,847	40,321	187,112	(2,088,168)	187,112
Goodwill	—	45,107	33,986	—	79,093
Other assets, net	45,884	39,371	29,099	(35,354)	79,000
Due from subsidiaries/parent	100,612	106,637	—	(207,249)	—
	$ 2,942,310	$ 2,221,036	$ 912,259	$ (2,430,346)	$ 3,645,259
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 72,029	$ 47,988	$ 45,468	$ (1)	$ 165,484
Accrued liabilities	68,517	96,529	32,920	—	197,966
Income taxes payable	—	17,345	2,106	(19,451)	—
Current maturities of long-term debt	4,326	—	19,633	(13,114)	10,845
Total current liabilities	144,872	161,862	100,127	(32,566)	374,295
Long-term debt	1,236,532	—	110,166	—	1,346,698
Deferred income taxes	169,818	156,877	89,195	(17,241)	398,649
Asset retirement obligations	—	163,372	—	—	163,372
Other long-term liabilities	1,832	4,971	689	77	7,569
Due to parent	—	—	126,097	(126,097)	—
Total liabilities	1,553,054	487,082	426,274	(175,827)	2,290,583
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,388,256	1,733,954	485,985	(2,254,519)	1,353,676
	$ 2,942,310	$ 2,221,036	$ 912,259	$ (2,430,346)	$ 3,645,259

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

	As of December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 258,742	$ 2,522	$ 9,409	$ —	$ 270,673
Accounts receivable, net	49,813	77,399	18,307	—	145,519
Unbilled revenue	9,425	480	17,254	—	27,159
Income taxes receivable	38,333	—	13,795	(43,636)	8,492
Other current assets	54,144	68,910	16,331	(25,668)	113,717
Total current assets	410,457	149,311	75,096	(69,304)	565,560
Intercompany	106,408	149,796	(190,729)	(65,475)	—
Property and equipment, net	220,408	1,919,412	729,131	(5,245)	2,863,706
Other assets:					
Equity investments in unconsolidated affiliates	—	—	189,411	—	189,411
Equity investments in affiliates	2,123,169	29,649	—	(2,152,818)	—
Goodwill, net	—	45,107	33,536	—	78,643
Other assets, net	48,822	41,669	22,919	(31,197)	82,213
Due from subsidiaries/parent	73,867	64,775	—	(138,642)	—
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 58,451	$ 79,128	$ 17,878	$ —	$ 155,457
Accrued liabilities	81,021	104,450	15,136	—	200,607
Income taxes payable	—	54,955	—	(54,955)	—
Current maturities of long-term debt	4,326	—	33,837	(25,739)	12,424
Total current liabilities	143,798	238,533	66,851	(80,694)	368,488
Long-term debt	1,233,504	—	114,811	—	1,348,315
Deferred income taxes	137,662	222,528	90,676	(8,259)	442,607
Asset retirement obligations	—	176,657	5,742	—	182,399
Other long-term liabilities	924	2,495	766	77	4,262
Due to parent	—	—	99,352	(99,352)	—
Total liabilities	1,515,888	640,213	378,198	(188,228)	2,346,071
Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,461,243	1,759,506	481,166	(2,274,453)	1,427,462
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533

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

	Three Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 82,764	$ 212,105	$ 111,581	$ (13,781)	$ 392,669
Cost of sales	42,397	184,369	92,765	(13,414)	306,117
Gross profit (loss)	40,367	27,736	18,816	(367)	86,552
Gain on oil & gas derivative contracts	—	161	—	—	161
Loss on sale of assets	—	—	13	—	13
Selling and administrative expenses	(15,465)	(7,370)	(4,212)	419	(26,628)
Income (loss) from operations	24,902	20,527	14,617	52	60,098
Equity in earnings of investments	27,871	7,567	6,221	(35,438)	6,221
Net interest expense and other	(19,452)	(3,996)	2,041	—	(21,407)
Income (loss) before income taxes	33,321	24,098	22,879	(35,386)	44,912
Provision (benefit) for income taxes	7,185	4,530	6,234	16	17,965
Income from continuing operations	26,136	19,568	16,645	(35,402)	26,947
Discontinued operations, net of tax	—	—	—	—	—
Net income (loss) applicable to Helix	26,136	19,568	16,645	(35,402)	26,947
Less:net income applicable to noncontrolling interests	—	—	—	(776)	(776)
Preferred stock dividends	(10)	—	—	—	(10)
Net income (loss) applicable to Helix common shareholders	$ 26,126	$ 19,568	$ 16,645	$ (36,178)	$ 26,161

	Three Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 17,350	$ 146,981	$ 70,730	$ (19,036)	$ 216,025
Cost of sales	17,952	161,474	52,217	(18,235)	213,408
Gross profit (loss)	(602)	(14,493)	18,513	(801)	2,617
Gain on oil & gas derivative contracts	—	4,598	—	—	4,598
Gain on sale of assets	—	—	—	—	—
Selling and administrative expenses	(12,791)	(5,467)	(4,364)	738	(21,884)
Income (loss) from operations	(13,393)	(15,362)	14,149	(63)	(14,669)
Equity in earnings of investments	6,081	2,625	13,923	(9,244)	13,385
Gain on sale of Cal Dive common stock	17,901	—	—	—	17,901
Net interest expense and other	(65)	(6,156)	(4,084)	(1)	(10,306)
Income (loss) before income taxes	10,524	(18,893)	23,988	(9,308)	6,311
Provision (benefit) for income taxes	8,765	(6,120)	1,686	137	4,468
Income from continuing operations	1,759	(12,773)	22,302	(9,445)	1,843
Discontinued operations, net of tax	3,021	—	—	—	3,021
Net income (loss) applicable to Helix	4,780	(12,773)	22,302	(9,445)	4,864
Less:net income applicable to noncontrolling interests	—	—	—	(844)	(844)
Preferred stock dividends	(125)	—	—	—	(125)

Net income (loss) applicable to Helix common shareholders	$ 4,655	$ (12,773)	$ 22,302	$ (10,289)	$ 3,895

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

	Nine Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 137,456	$ 568,075	$ 256,639	$ (68,669)	$ 893,501
Cost of sales	73,889	641,568	215,067	(54,613)	875,911
Gross profit (loss)	63,567	(73,493)	41,572	(14,056)	17,590
Gain on oil & gas derivative contracts	—	2,643	—	—	2,643
Gain on sale of assets	—	287	5,959	—	6,246
Selling and administrative expenses	(52,923)	(25,285)	(14,788)	1,321	(91,675)
Income (loss) from operations	10,644	(95,848)	32,743	(12,735)	(65,196)
Equity in earnings of investments	(36,865)	10,672	12,932	26,193	12,932
Net interest expense and other	(42,133)	(16,564)	(6,085)	—	(64,782)
Income (loss) before income taxes	(68,354)	(101,740)	39,590	13,458	(117,046)
Provision (benefit) for income taxes	517	(40,606)	2,584	(4,457)	(41,962)
Income from continuing operations	(68,871)	(61,134)	37,006	17,915	(75,084)
Discontinued operations, net of tax	(27)	—	(17)	—	(44)
Net income (loss) applicable to Helix	(68,898)	(61,134)	36,989	17,915	(75,128)
Less:net income applicable to noncontrolling interests	—	—	—	(2,049)	(2,049)
Preferred stock dividends	(104)	—	—	—	(104)
Net income (loss) applicable to Helix common shareholders	$ (69,002)	$ (61,134)	$ 36,989	$ 15,866	$ (77,281)

	Nine Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 207,338	$ 559,712	$ 587,912	$ (73,323)	$ 1,281,639
Cost of sales	160,304	429,299	461,479	(69,026)	982,056
Gross profit	47,034	130,413	126,433	(4,297)	299,583
Gain on oil & gas derivative contracts	—	83,328	—	—	83,328
Gain on sale of assets	—	1,773	—	—	1,773
Selling and administrative expenses	(37,421)	(21,347)	(46,938)	3,097	(102,609)
Income (loss) from operations	9,613	194,167	79,495	(1,200)	282,075
Equity in earnings of investments	186,907	463	28,051	(188,269)	27,152
Gain on sale of Cal Dive common stock	77,343	—	—	—	77,343
Net interest expense and other	(14,674)	(12,271)	(12,036)	(988)	(39,969)
Income (loss) before income taxes	259,189	182,359	95,510	(190,457)	346,601
Provision (benefit) for income taxes	45,327	63,502	18,099	(732)	126,196
Income from continuing operations	213,862	118,857	77,411	(189,725)	220,405
Discontinued operations, net of tax	205	—	10,098	—	10,303
Net income (loss) applicable to Helix	214,067	118,857	87,509	(189,725)	230,708
Less:net income applicable to noncontrolling interests	—	—	—	(19,017)	(19,017)
Preferred stock dividends	(688)	—	—	—	(688)

Preferred stock beneficial conversion charges	(53,439)	—	—	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ 159,940	$ 118,857	$ 87,509	$ (208,742)	$ 157,564

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

	Nine Months Ended September 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ (68,898)	$ (61,134)	$ 36,989	$ 17,915	$ (75,128)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	36,866	(10,673)	—	(26,193)	—
Other adjustments	70,963	229,567	33,719	(17,311)	316,938
Cash provided by (used in) continuing operations	38,931	157,760	70,708	(25,589)	241,810
Cash provided by (used in) discontinued operations	—	—	(44)	—	(44)
Net cash provided by (used in) operating activities	38,931	157,760	70,664	(25,589)	241,766
Cash flows from investing activities:					
Capital expenditures	(54,880)	(104,423)	(19,715)	—	(179,018)
Distributions from equity investments, net	—	—	2,108	—	2,108
Insurance recovery	7,020	9,086	—	—	16,106
Other	—	719	—	—	719
Net cash used in investing activities	(47,860)	(94,618)	(17,607)	—	(160,085)
Cash flows from financing activities:					
Repayments of debt	(3,245)	—	(4,866)	—	(8,111)
Deferred financing costs	(2,864)	—	—	—	(2,864)
Preferred stock dividends paid and other	231	—	(1,842)	—	(1,611)
Repurchase of common stock	(11,659)	—	—		(11,659)
Excess tax benefit from stock-based compensation	(2,376)	—	—	—	(2,376)
Intercompany financing	73,887	(61,811)	(37,665)	25,589	—
Net cash provided by (used in) financing activities	53,974	(61,811)	(44,373)	25,589	(26,621)
Effect of exchange rate changes on cash and cash equivalents	—	—	(253)	—	(253)
Net increase (decrease) in cash and cash equivalents	45,045	1,331	8,431	—	54,807
Cash and cash equivalents:					
Balance, beginning of year	258,742	2,522	9,409	—	270,673
Balance, end of period	$ 303,787	$ 3,853	$ 17,840	$ —	$ 325,480

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

	Nine Months Ended September 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 214,067	$ 118,857	$ 87,509	$ (189,725)	$ 230,708
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	(1,121)	899	(222)
Equity in earnings of affiliates	(186,907)	(463)	—	187,370	—
Other adjustments	(168,906)	90,361	73,197	212,123	206,775
Cash provided by (used in) operating activities	(141,746)	208,755	159,585	210,667	437,261
Cash provided by discontinued operations	—	—	(6,089)	—	(6,089)
Net cash provided by (used in) operating activities	(141,746)	208,755	153,496	210,667	431,172
Cash flows from investing activities:					
Capital expenditures	(9,098)	(157,686)	(139,368)	—	(306,152)
Investments in equity investments	—	—	(551)	—	(551)
Distributions from equity investments, net	—	—	4,774	—	4,774
Proceeds from sale of Cal Dive common stock	504,168	—	(112,995)	(86,000)	305,173
Proceeds from sales of property	—	23,238	—	—	23,238
Other	—	(13)	—	—	(13)
Cash provided by (used in) investing activities	495,070	(134,461)	(248,140)	(86,000)	26,469
Cash provided by discontinued operations	—	—	20,872	—	20,872
Net cash used in investing activities	495,070	(134,461)	(227,268)	(86,000)	47,341
Cash flows from financing activities:					
Borrowings on revolver	—	—	100,000	—	100,000
Repayments on revolver	(349,500)	—	—	—	(349,500)
Repayments of debt	(3,245)	—	(24,214)	—	(27,459)
Deferred financing costs	(50)	—	—	—	(50)
Preferred stock dividends paid	(625)	—	—		(625)
Repurchase of common stock	(10,603)	—	(86,000)	86,000	(10,603)
Excess tax benefit from stock-based compensation	(2,036)	—	—	—	(2,036)
Exercise of stock options, net	36				36
Intercompany financing	266,551	(76,880)	20,996	(210,667)	—
Net cash provided by (used in) financing activities	(99,472)	(76,880)	10,782	(124,667)	(290,237)
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,383)	—	(1,383)
Net increase (decrease) in cash and cash equivalents	253,852	(2,586)	(64,373)	—	186,893
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613

Balance, end of period	$ 402,556	$ 2,397	$ 5,553	$ —	$ 410,506

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," "potential," "should," "could" and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy, including the potential sale of assets and/or other investments in our subsidiaries and facilities, or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any oil and gas property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed 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 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 current and anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions and their effect on us;
- 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 regarding our ability to collect outstanding receivables;
- statements related to our expectation and ability to prevail in certain disputes;
- statements regarding the timing or completion of contracts;
- statements regarding our funding or financings plans;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

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

- impact of the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, and 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 Part II - Item 1A. “Risk Factors” located elsewhere in this Quarterly Report on Form 10-Q, as well as our Quarterly Report on Form 10-Q for the period ended June 30, 2010, and in Item 1A “Risk Factors” in our 2009 Annual Report on Form 10-K (“2009 Form 10-K”). All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

EXECUTIVE SUMMARY

Our Business

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

Our Strategy

Over the past two years, we have focused on improving our balance sheet by increasing our liquidity through reductions in planned capital spending as well as dispositions of our non-core business assets. Since the beginning of 2009, dispositions of non-core business assets resulted in receipt of the following pre-tax proceeds:

- Sold six oil and gas properties for approximately $25 million;
- Sold a total of 15.2 million shares of CDI common stock held by us to CDI for $100 million in separate transactions in January and June 2009;
- Sold a total of 45.8 million shares of CDI common stock held by us to third parties in two separate public secondary offerings for approximately $404.4 million, net of underwriting fees in June 2009 and September 2009 (for additional information regarding the sales of CDI common shares by us see Note 4); and
- Sold Helix RDS Limited, our subsurface reservoir consulting business for $25 million in April 2009.

In March 2010, we announced the engagement of advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. At the time of the filing of this Current Report on Form 10-Q, we do not have an approved or definitive plan for the disposition of our oil and gas business. We are unable to be specific regarding a timetable for any disposition, the completion of which will be largely dependent on the evolving economic and financial market conditions as well as regulatory developments with respect to the Gulf of Mexico oil and gas business.

Economic Outlook and Industry Influences

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our 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, 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.

The NYMEX West Texas Intermediate crude oil price has averaged $77.65 per barrel over the nine-month period ended September 30, 2010. Although this price level is generally favorable to support potential additional capital investment in exploration and development activities, this price remains significantly lower than the historical high prices realized in mid-to-late 2008. The NYMEX Henry Hub natural gas price began 2010 with prices approximating $6.00 per Mmbtu; however the price has since decreased to the current approximate range of $3.50 to $4.00 per Mmbtu. Prices for natural gas are near decade lows and reflect the increased supply from non-traditional sources of natural gas such as production from shale formations and tight sands as well as decreased demand following the economic downturn that commenced in mid-to-late 2008. Although there have been signs that the economy is improving, most economists believe the recovery will be slow and may take years to recover to levels previously achieved. The oil and natural gas industry has been adversely affected by the uncertainty of the general timing and level of the economic recovery as well as more recently the uncertainties concerning increased government regulation of the industry in the United States (as further discussed below).

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252 (Note 2). The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which was unprecedented in U.S territorial waters. In May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. This moratorium also affected 33 in progress deepwater wells. The moratorium on drilling in the shallow water of the Gulf, defined as water depths less than 500 feet, was lifted in late May 2010. However, the DOI extended the drilling moratorium on deepwater wells through November 2010. On October 12, 2010, the DOI lifted the drilling moratorium and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. No deepwater drilling permits have been issued since the lifting of the drilling moratorium and relatively few shallow water drilling permits have been issued since its ban was lifted in May 2010.

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

Over the longer-term, the fundamentals for our business remain generally favorable as the need for the continual replenishment of oil and gas production should drive the demand for our services.

Goodwill

At September 30, 2010, the amount of goodwill in our accompanying consolidated condensed balance sheet totaled $79.1 million, with all of these amounts being associated with our Contracting Services businesses. Goodwill is an asset that does not amortize but rather must periodically be assessed for impairment. We have concluded that no impairment indicators have been present to require a test during the interim periods of 2010. We are required to perform our annual assessment as of November 1, 2010.

RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two continuing reportable segments. As a result, our reportable segments consist of the following: Contracting Services, Oil and Gas and Production Facilities. Formerly, we had a third contracting services segment, Shelf Contracting. In June 2009, we ceased consolidating our Shelf Contracting segment, which represented the results and operations of Cal Dive, following the sale of a substantial amount of our ownership of Cal Dive (Note 4). However, each line item within our consolidated statement of operations for the nine-month period ended September 30, 2010 is impacted significantly when compared to the same periods last year as a result of the deconsolidation of the Cal Dive results. The amounts for the three-month periods ended September 30, 2010 and 2009 are comparable as we deconsolidated Cal Dive in June 2009. We continued to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009. See Note 4 elsewhere in this Quarterly Report on Form 10-Q and Note 3 of our 2009 Form 10-K for additional disclosure regarding our transactions that substantially eliminated our ownership interest in Cal Dive.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and production facilities. Our Contracting Services business operates primarily in the Gulf of Mexico, the North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. As of September 30, 2010, our Contracting Services operations had backlog of approximately $299 million, including $267 million through December 31, 2011. Our Contracting Services backlog includes amounts for the *HP I* and the *Caesar* that were placed in service during the second quarter of 2010. At December 31, 2009, our Contracting Services backlog totaled approximately $251 million, including $217 million for 2010. Backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

We began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to generate incremental returns. We 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 have been 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. Our oil and gas business currently operates exclusively in the Gulf of Mexico. 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.

Mid-Year Reserve Assessment

In connection with our regular mid-year review as well as our efforts to pursue potential divestment alternatives for our oil and gas assets, we engaged an independent petroleum reservoir engineering firm to update our estimates of proved reserves for our domestic oil and gas properties as of June 30, 2010. The resulting independent petroleum engineer's reserve report indicated the we had a significant reduction in proved reserves (approximately 143 Bcfe from year end 2009) resulting from a combination of factors including well performance issues at certain of our producing fields, most notably our Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our other oil and gas properties. The changes in field economics primarily affected properties that were either close to the end of their production life or in which we had proved undeveloped reserves, which would have been required to be developed in the near term The decision not to develop these properties in light of these economic changes was also driven by our desire to pursue potential alternatives to divest our oil and gas assets and the increasing uncertainties about future oil and gas operations in the Gulf of Mexico as a result of the oil spill from the Macondo well. As a result of the reduction in estimated reserves we were required to record oil and gas property impairment charges totaling $159.9 million at June 30, 2010.

The total present value of the future cash flows of our estimated proved reserves at June 30, 2010 as discounted by the SEC mandated 10% discount was approximately $1.3 billion, which is substantially the same amount we reported at December 31, 2009 (see Note 20 of our 2009 Annual Report on Form 10-K). The reason for the relative lack of change in our future cash flows despite the rather substantial reduction in estimated proved reserves can be primarily attributed to the higher natural gas and oil prices used at June 30, 2010 as compared to those used at December 31, 2009 (see table below) and the reduction of some or all of the future development costs associated with projects that we have now concluded do not merit future development because of updated economics.

Six Months Ended June 30, 2010— (1)		
Oil price per Bbl	$	73.15
Natural gas price per Mcf	$	4.07
Year Ended December 31, 2009—(1)		
Oil price per Bbl	$	58.05
Natural gas price per Mcf	$	3.72

(1) Price at June 30, 2010 and December 31, 2009 represents the average trailing twelve month price for both oil and natural gas as now required under the new accounting standards.

See "Comparison of Three Months Ended September 30, 2010 and 2009" below for the amount of oil and natural gas we produced in the third quarter of 2010. We will engage an independent petroleum engineering firm to prepare a report of the estimate of our proved reserves at December 31, 2010.

Impairments

Following the determination of a significant reduction in our estimates of reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million in the second quarter of 2010 which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. The Bushwood field was not impaired; however, our revised depletion rate for the field increased substantially, which has resulted in an incremental $33.7 million of depletion expense being recorded in 2010 compared to what would have been recorded had there been no change in the Bushwood field's estimated proved reserves at June 30, 2010. See Note 6 for more information regarding our impairment charges.

Discontinued Operations

In April 2009, we sold Helix RDS Limited, a provider of reservoir engineering, geophysical production technology and associated specialized consulting services to the upstream oil and gas industry, 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.

Comparison of Three Months Ended September 30, 2010 and 2009

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 238,531	$ 175,091	$ 63,440
Oil and Gas	95,566	63,715	31,851
Production Facilities	74,458	1,141	73,317
Intercompany elimination	(15,886)	(23,922)	8,036
	$ 392,669	$ 216,025	$ 176,644
Gross profit (loss) (in thousands) –			
Contracting Services	$ 42,149	$ 29,104	$ 13,045
Oil and Gas	1,083	(22,291)	23,374
Production Facilities	44,616	(1,318)	45,934
Corporate	(1,010)	(907)	(103)
Intercompany elimination	(286)	(1,971)	1,685
	$ 86,552	$ 2,617	$ 83,935
Gross Margin –			
Contracting Services	18%	17%	1 pts
Oil and Gas	1%	(35)%	36 pts
Total company	22%	1%	21 pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/97%	8/77%	
Well operations	4/83%	2/92%	
ROVs	46/68%	47/74%	

(1) Represents number of 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 three-month periods ended September 30, 2010 and 2009 were as follows (in thousands):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase/ (Decrease)
Contracting Services	$ 15,886	$ 23,922	$ (8,036)
Production Facilities	—	—	—
	$ 15,886	$ 23,922	$ (8,036)

Intercompany segment profit during the three-month periods ended September 30, 2010 and 2009 was as follows (in thousands):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase/ (Decrease)
Contracting Services	$ 330	$ 2,153	$ (1,823)
Production Facilities	(44)	(44)	—
Shelf Contracting	—	(138)	138
	$ 286	$ 1,971	$ (1,685)

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	751	546	205
Oil sales revenue (in thousands)	$ 55,314	$ 37,576	$ 17,738
Average oil sales price per Bbl (excluding hedges)	$ 74.68	$ 68.86	$ 5.82
Average realized oil price per Bbl (including hedges)	$ 73.63	$ 68.86	$ 4.77
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 2,603		
Change in production volume (in thousands)	15,135		
Total increase in oil sales revenue (in thousands)	$ 17,738		
Gas production volume (MMcf)	5,875	6,534	(659)
Gas sales revenue (in thousands)	$ 36,039	$ 24,355	$ 11,684
Average gas sales price per mcf (excluding hedges)	$ 4.74	$ 3.59	$ 1.15
Average realized gas price per mcf (including hedges)	$ 6.13	$ 3.73	$ 2.40
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 15,728		
Change in production volume (in thousands)	(4,044)		
Total increase in gas sales revenue (in thousands)	$ 11,684		
Total production (MMcfe)	10,383	9,808	575

Price per Mcfe	$ 8.80	$ 6.31	$ 2.49
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 91,352	$ 61,930	$ 29,422
Other revenues(1)	4,214	1,785	2,429
	$ 95,566	$ 63,715	$ 31,851

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements. Amount during the three-month period ended September 30, 2010 includes $2.7 million related to settlement of a royalty claim.

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

	Three Months Ended September 30,			
	2010		2009	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 27,406	$ 2.64	$ 25,109	$ 2.56
Workover	3,701	0.36	5,940	0.61
Transportation	1,889	0.18	3,044	0.31
Repairs and maintenance	2,646	0.25	4,143	0.42
Overhead and company labor	1,992	0.19	2,468	0.25
	$ 37,634	$ 3.62	$ 40,704	$ 4.15
Depletion expense (3)	$ 50,677	$ 4.88	$ 31,348	$ 3.20
Abandonment	150	0.01	2,913	0.30
Accretion expense	3,743	0.36	3,539	0.36
Net hurricane costs	940	0.09	5,061	0.52
Impairment	897	0.09	1,537	0.16
	56,407	5.43	44,398	4.54
Total	$ 94,041	$ 9.05	$ 85,102	$ 8.69

(1) Excludes exploration expense of $0.4 million and $0.9 million for the three month periods ended September 30, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.
(2) Includes production taxes.
(3) Includes an incremental $15.0 million of depletion charges related to our Bushwood field following reductions in our estimated proved reserves at June 30, 2010, which increased our depletion rate for the field (Note 6).

Revenues. Our Contracting Services revenues increased 36% for the three-month period ended September 30, 2010 compared to the same period in 2009 reflecting higher utilization of our subsea construction vessels, partially offset by a decrease in the utilization of our well operation and intervention vessels. The well operations and intervention vessel utilization rate was adversely impacted by the *Well Enhancer* initiating its coiled tubing unit upgrade in August 2010. The vessel returned to service in October. The substantial increase in revenues related to our Production Facilities segment reflects the use of the *HP I* in the oil spill containment efforts. The utilization rate for our ROV business decreased slightly but margins remained strong. Our third quarter 2010 revenues included amounts earned by the contracting of the *Q4000*, the *Express* and the *HP I* to assist in the Gulf oil spill response and containment efforts. These vessels were released from these services by BP in October. Separately, in the 2009 period we had significant revenues associated with a large international construction project for which we completed our scope of work in the third quarter of 2009.

Oil and Gas revenues increased 50% during the three month period ended September 30, 2010 as compared to the same period in 2009. The increase in revenues is attributable to higher prices received for our natural gas and oil sales volumes, in particular our natural gas sales realization price which increased by 64%. Our production also increased by 0.6 billion cubic feet of natural gas equivalent (Bcfe) in the third quarter of 2010 as compared to the same period in 2009. The increase in production primarily reflects the incremental production from the Bushwood field following certain recompletion and development activities that were completed in the first quarter of 2010. For the period October 1, 2010 through October 26, 2010, our production rate approximated 125 MMcfe/d as compared to an approximate average of 113 MMcfe/d in the third quarter of 2010. The October rate includes the commencement of production from the Phoenix field on October 19, 2010.

Gross Profit. Our Contracting Services gross profit increased by 45% primarily reflecting work in the Gulf oil spill and containment response efforts coupled with the relatively low margin that our large international construction project earned in the prior year. Our contracting services gross profit was adversely affected by two negative margin jobs during the quarter. The first was the initial pipelay project utilizing the *Caesar* and the other is the ongoing well abandonment project located offshore China (Note 16), utilizing the *Normand Clough,* a vessel chartered from our CloughHelix JV (Note 8). The total losses recorded for these two projects totaled $20.5 million in the third quarter of 2010.

Our oil and gas operating gross profit for the three-month period ended September 30, 2010 increased by $23.4 million compared to the same period in 2009. The increase primarily reflects the higher oil production in the third quarter of 2010 compared to the same period of 2009. Our oil sales have a higher margin than our natural gas sales on a per Mcfe basis.

Selling and Administrative Expenses. Selling and administrative expenses of $26.6 million for the third quarter of 2010 were $4.7 million higher than the $21.9 million incurred in the same prior year period. The increase primarily reflects the establishment of an allowance for doubtful accounts reserve associated with our trade receivable balance for a large international construction contract.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $7.2 million during the three-month period ended September 30, 2010 as compared to the same prior year period. Our equity in earnings for the three-month period ended September 30, 2009 includes $7.2 million related to our approximate 26% ownership interest in Cal Dive. The decrease in our share of the earnings of Deepwater Gateway and Independence Hub were offset by our $0.7 million share of the income from the CloughHelix JV in Australia (Note 8).

Net Interest Expense. Our net interest expense was $25.5 million in third quarter 2010 as compared to $7.3 million in the same prior year period. The increase primarily reflects that we had no capitalized interest for three-month period ended September 30, 2010 as compared with $16.1 million for the same period last year. The decrease in our capitalized interest was primarily attributable to the completion of our major capital projects in 2010, including placing the *Caesar* and *HP I* vessels in service during the second quarter of 2010.

Other Income (Expense). We incurred foreign exchange gains and losses related to fluctuations in our non U.S dollar functional currencies and currency contracts. We recorded a $4.3 million gain in the third quarter of 2010 compared to a loss of $3.1 million in third quarter of 2009. The gains on our foreign exchange forward contracts totaled $1.1 million in the third quarter of 2010 compared to a loss of $1.9 million in the third quarter of 2009 (Note 18).

Provision for Income Taxes. Income taxes increased to $18.0 million in the third quarter of 2010 compared to $4.5 million in the same prior year period. The increase is primarily due to increased profitability in the current year period and the deconsolidation of CDI in 2009.

Comparison of Nine Months Ended September 30, 2010 and 2009

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 595,048	$ 645,422	$ (50,374)
Shelf Contracting	—	404,709	(404,709)
Oil and Gas	288,867	313,888	(25,021)
Production Facilities	97,169	2,261	94,908
Intercompany elimination	(87,583)	(84,641)	(2,942)
	$ 893,501	$ 1,281,639	$ (388,138)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase/ (Decrease)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 130,104	$ 117,721	$ 12,383
Shelf Contracting	—	92,728	(92,728)
Oil and Gas	(149,036)	97,434	(246,470)
Production Facilities	57,715	(2,177)	59,892
Corporate	(2,471)	(2,231)	(240)
Intercompany elimination	(18,722)	(3,892)	(14,830)
	$ 17,590	$ 299,583	$ (281,993)
Gross Margin –			
Contracting Services	22%	18%	4 pts
Shelf Contracting	—	23%	N/A
Oil and Gas	(52)%	31%	(83) pts
Total company	2%	23%	(21) pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	8/84%	8/81%	
Well operations	4/81%	2/89%	
ROVs	46/63%	47/70%	
Shelf Contracting	N/A	N/A	

(1) Represents number of 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 nine-month periods ended September 30, 2010 and 2009 were as follows (in thousands):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase/ (Decrease)
Contracting Services	$ 84,053	$ 76,776	$ 7,277
Production Facilities	3,530	—	3,530
Shelf Contracting	—	7,865	(7,865)
	$ 87,583	$ 84,641	$ 2,942

Intercompany segment profit during the nine-month periods ended September 30, 2010 and 2009 was as follows (in thousands):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase/ (Decrease)
Contracting Services	$ 15,473	$ 3,600	$ 11,873
Production Facilities	3,249	(73)	3,322
Shelf Contracting	—	365	(365)
	$ 18,722	$ 3,892	$ 14,830

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	2,196	2,171	25
Oil sales revenue (in thousands)	$ 159,688	$ 143,231	$ 16,457
Average oil sales price per Bbl (excluding hedges)	$ 75.24	$ 62.23	$ 13.01
Average realized oil price per Bbl (including hedges)	$ 72.71	$ 65.96	$ 6.75
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 14,655		
Change in production volume (in thousands)	1,802		
Total increase in oil sales revenue (in thousands)	$ 16,457		
Gas production volume (MMcf)	20,365	21,060	(695)
Gas sales revenue (in thousands)	$ 121,814	$ 93,522	$ 28,292
Average gas sales price per mcf (excluding hedges)	$ 4.83	$ 4.03	$ 0.80
Average realized gas price per mcf (including hedges)	$ 5.98	$ 4.44	$ 1.54
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 32,448		
Change in production volume (in thousands)	(4,156)		
Total increase in gas sales revenue (in thousands)	$ 28,292		
Total production (MMcfe)	33,541	34,088	(547)
Price per Mcfe	$ 8.39	$ 6.95	$ 1.44
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 281,502	$ 236,753	$ 44,749
Other revenues(1)	7,365	77,135	(69,770)
	$ 288,867	$ 313,888	$ (25,021)

(1) Other revenues include fees earned under our process handling agreements. The amount in 2009 also included $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 (Note 6).

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

	Nine Months Ended September 30, 2010 Total	2010 Per Mcfe	2009 Total	2009 Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 57,728	$ 1.72	$ 61,576	$ 1.81
Workover	18,818	0.56	7,635	0.22
Transportation	4,218	0.13	6,465	0.19
Repairs and maintenance	6,179	0.18	9,329	0.27
Overhead and company labor	5,465	0.16	6,829	0.20
	$ 92,408	$ 2.75	$ 91,834	$ 2.69

Depletion expense[3]	$ 154,283	$ 4.60	$ 116,510	$ 3.42
Abandonment	1,316	0.04	4,444	0.13
Accretion expense	11,686	0.35	11,601	0.34
Net hurricane costs (reimbursements)	4,559	0.14	(24,139)	(0.71)
Impairment	171,871	5.12	13,341	0.39
	343,715	10.25	121,757	3.57
Total	$ 436,123	$ 13.00	$ 213,591	$ 6.26

(1) Excludes exploration expense of $1.8 million and $2.9 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.
(2) Includes production taxes.
(3) Includes an incremental $33.7 million of depletion charges related to our Bushwood field following reductions in our estimated proved reserves at June 30, 2010, which increased the field's depletion rate (Note 6).

The following table contains selected data extracted from our condensed consolidated statements of operations. This information is presented to illustrate the amounts associated with our Contracting Services, including our Production Facilities segment, the operations of which substantially increased when the *HP I* was placed in service in the second quarter of 2010 and our Oil and Gas business and to facilitate the understanding of the variances in our results of operations for the comparative nine-month periods ended September 30, 2010 and 2009:

	2010			2009		
	Contracting Services	Oil and Gas	Total	Contracting Services	Oil and Gas	Total
	(in thousands)					
Revenues	$ 604,634	$ 288,867	$893,501	$ 967,751	$ 313,888	$ 1,281,639
Gross profit (loss)	166,626	(149,036)	17,590	202,149	97,434	299,583
Gain on sale or acquisition of assets	—	6,246	6,246	70	1,703	1,773
Selling and administrative expenses	71,831	19,844	91,675	86,830	15,779	102,609
Equity in earnings of investment	12,932	—	12,932	27,152	-	27,152
Net interest expense and other	50,659	14,123	64,782	24,474	15,495	39,969

The following table modifies the preceding table to illustrate the effect that our former Shelf Contracting business (Cal Dive) had on our Contracting Services and Production Facilities operating results over the first half of 2009 (Note 4). These results are provided to facilitate the understanding of the variances discussed below of our operations as reported on an continuing basis for the comparative nine- month periods ended September 30, 2009 and 2010 (amounts in thousands):

	2009			2010	
	Contracting Services as reported	Less Shelf Contracting	Continuing Contracting Services	Contracting Services	Variance Of Continuing Contracting Services
			(in thousands)		
Revenues	$ 967,751	$ 404,709	$ 563,042	$ 604,634	$ 41,592
Gross Profit	202,149	92,728	109,421	166,626	57,205
Gain on sale or acquisition of assets	70	—	70	—	(70)
Selling and administrative expenses	86,830	33,651	53,179	71,831	18,652
Equity in earnings of investment	27,152	8,100	19,052	12,932	(6,120)
Net interest expense and other	24,474	6,642	17,832	50,659	32,827

In the following discussion of our results of operations the discussion of our Contracting Services specifically refers to those businesses which we continue to operate, including both our Contracting Services and Production Facilities segments. We no longer have any Shelf Contracting operations. The preceding table illustrates the variances of our continuing Contracting Services that are discussed below

Revenues. Contracting Services revenues increased 7% for the nine-month period ended September 30, 2010 compared to the same period in 2009. Our Production Facilities revenues increased by $94.9 million for the nine-month period ended September 30, 2010 compared to the same period last year primarily reflecting the *HP I* being placed in service in 2010 and the subsequent contracting of the vessel to BP to participate in the oil spill containment efforts in the Gulf of Mexico. Excluding the Production Facilities revenues, our continuing Contracting Services revenues decreased by 8% for the nine- month period ended September 30, 2010 compared to the same period last year reflecting the increased amount of internal vessel utilization to develop our oil and gas properties in the first half of 2010, the scheduled regulatory dry docking of our *Seawell* vessel in February 2010, and the completion of a large international construction project in the third quarter of 2009. Overall utilization levels for our well operations vessels and ROVs decreased. Our revenues in 2010 have benefitted from two

Contracting Services vessels being added to our fleet since September 30, 2009 (the *Well Enhancer* in October 2009 and the *Caesar* in May 2010). As previously noted our *Q4000, Express* and *HP I* vessels were all involved in the Gulf oil spill containment efforts but all three vessels have been released by BP in October.

Oil and Gas revenues decreased 8% during the nine-month period ended September 30, 2010 compared to the same period in 2009. The decrease is substantially attributable to the $73.5 million of previously accrued royalty payments that we recognized in the first quarter of 2009 following a favorable judicial ruling in the dispute over the lessee's responsibility to make these payments with respect to the Gunnison leases (Note 6). For additional information regarding the resolution of these previously disputed royalty payments see Note 17 of our 2009 Form 10-K. Excluding the effect of these royalty payments being reversed our oil and gas revenues increased by 20% primarily reflecting higher oil and natural gas prices. Our production was 0.5 Bcfe less for the nine-month period ended September 30, 2010 compared to the same period in 2009. Our production for the nine months ended September 30, 2010 benefited from increased production from our Bushwood field, including commencement of production from our Danny oil reservoir in February 2010. This increase in our deepwater production was more than offset by decreases in production from our shelf properties and mechanical platform issues at our East Cameron Block 346 field in the first quarter of 2010, which were resolved in April 2010. Initial production from our Phoenix field commenced on October 19, 2010. Initial production from this field was delayed when we contracted the *HP I* to BP to assist in the Gulf oil spill containment efforts.

Gross Profit. Our Contracting Services gross profit increased by 52% primarily reflecting the utilization of the *HP I* for oil spill containment efforts for the entire third quarter of 2010. Excluding the gross profit related to our Production Facilities the gross profit for our Contracting Services decreased by 2% reflecting the lower vessel utilization for our well operations vessels and robotics and our increased scope of internal work related to the development of our oil and gas properties in the first half of 2010.

The Oil and Gas gross profit decrease of $246.5 million for the nine-month period ended September 30, 2010 compared to the same period in 2009 was primarily attributable to the reversal of the disputed accrued royalties discussed above, the insurance settlement agreement in June 2009 (Note 6), higher recorded impairment charges as further discussed below, increased workover costs mostly attributed to our Bushwood and East Cameron Block 346 fields and higher depletion rates for certain fields including the Bushwood field following the completion of the mid-year 2010 reserve report and resulting reserve reductions.

Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million in the second quarter of 2010 which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. Although our Bushwood field was not impaired, the revised depletion rate for the field increased substantially, which resulted in an incremental $33.7 million of depletion expense being recorded in the nine-month period ended September 30, 2010 compared to what would have been recorded had there been no change in the Bushwood field's estimated proved reserves at June 30, 2010. Further, following decreases in natural gas prices from those in effect at year end 2009, we were required to record $7.0 million of impairment expense in the first quarter of 2010 related to three of our U.S. Gulf of Mexico natural gas production fields and a $4.1 million impairment related to our only non-domestic (U.K.) oil and gas property. In the second quarter of 2009, we recorded $63.1 million of property impairment primarily related to new estimates of asset retirement obligations related to hurricane damaged properties. See Note 6 for additional information regarding our property impairments.

Gain on Sale or Purchase of Assets, Net. For the nine-month period ended September 30, 2010 our gain was primarily associated with the acquisition of the remaining 50% working interest related to the Camelot field in the United Kingdom (Note 6). The gain in the nine-month period ended September 30, 2009 reflected the sale of East Cameron Block 316 for gross proceeds of $18 million ($0.7 million gain) and the remaining 10% of our interest in the Bass Lite field in January 2009.

Selling and Administrative Expenses. Selling and administrative expenses of $91.7 million for the nine-month period ended September 30, 2010 were $22.7 million higher than the $69.0 million incurred in the same prior year period after excluding our Shelf Contracting expense. The increase primarily reflects the $17.5 million charge related to our settlement of litigation claims in Australia for the termination of an international construction contract and the establishment of an allowance for doubtful accounts reserve related to a separate international construction contract.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $14.2 million during the nine-month period ended September 30, 2010 compared to the same prior year period. In 2009, we recorded equity in earnings of $8.1 million related to our approximate 26% ownership of Cal Dive. This remaining decrease is primarily associated with our $5.0 million share of the losses of the CloughHelix JV (Note 8), which primarily reflects certain start-up costs. We also processed lower production throughput at both the Deepwater Gateway and Independence Hub facilities for the nine-month period ended September 30, 2010 compared to the same period in 2009.

Net Interest Expense. We reported net interest of $61.6 million for the nine-month period ended September 30, 2010 compared to $44.9 million in the same prior year period. Gross interest expense of $74.7 million during the nine-month period ended September 30, 2010 was lower than the $81.1 million incurred in 2009 reflecting both lower interest rates and balances outstanding as well as inclusion of $6.5 million of interest related to Cal Dive's debt that was deconsolidated in June 2009. Capitalized interest totaled $12.4 million for the nine-month period ended September 30, 2010 compared with $35.5 million for the same period last year. The decrease in our capitalized interest was primarily attributable to the completion of our major capital projects since September 30, 2009, more specifically during the first half of 2010, including placing in service our *Caesar* and *HP I* vessels. Interest income totaled $0.7 million for both nine-month periods ended September 30, 2010 and 2009.

Other Income (Expense). We incurred foreign exchange losses related to declines in our non U.S dollar functional currencies and currency contracts totaling $3.0 million for the nine-month period ended September 30, 2010 compared to gains of $5.0 million for the nine-month period ended September 30, 2009. Losses on our foreign exchange forward contracts totaled $2.4 million for the nine-month period ended September 30, 2010 compared gains of $3.3 million for the same period last year (Note 18).

Provision for Income Taxes. An income tax benefit of $42.0 million was recorded for the nine- month period ended September 30, 2010 compared to income tax expense of $126.2 million in the same prior year period. The variance primarily reflects decreased profitability in the current year period. The effective tax rate for the nine-month period ended September 30, 2010 was a 35.9% benefit; this was more favorable than the 36.4% tax provision that was recorded for the nine-month period ended September 30, 2009. The improved effective tax rate reflects the deconsolidation of CDI in 2009.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2010	December 31, 2009
	(in thousands)	
Net working capital	$ 294,981	$ 197,072
Long-term debt(1)	1,346,698	1,348,315

(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 standards effective January 1, 2009 (see Note 2 of our 2009 Form 10-K).

The carrying amount of our debt, including current maturities as of September 30, 2010 and December 31, 2009 is as follows:

	September 30, 2010	December 31, 2009
	(in thousands)	
Term Loan (matures July 2013)	$ 411,522	$ 414,766
Revolving Credit Facility (matures November 2012)	—	—
Convertible Senior Notes (matures March 2025) (1)	279,336	273,064
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures February 2027)	114,811	119,235
Loan Note(2)	1,874	3,674
Total	$ 1,357,543	$ 1,360,739

(1) Net of the unamortized debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 "*Convertible Debt and Other Options*" on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest expense through 2012, the date the note can first be put to us (Note 9).

(2) Assumed to be current, represents the loan provided by Kommandor RØMØ to Kommandor LLC (Note 16).

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 241,766	$ 431,172
Investing activities	$(160,085)	$ 47,341
Financing activities	$ (26,621)	$(290,237)

As of September 30, 2010, our liquidity totaled $699.3 million, including cash and cash equivalents of $325.5 million and $373.8 million of available borrowing capacity under our Revolving Credit Facility (Note 9).

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 reduce debt with additional free cash flow from operations and/or cash received from any dispositions of our non core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We may reduce planned capital spending and seek further additional dispositions of our non-core business assets. We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the significant hedged portion of our estimated oil and gas production through 2011. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility will be sufficient to fund our operations. In the first half of 2009, we repaid the remaining $349.5 million of borrowings outstanding under our Revolving Credit Facility.

In accordance with our Credit Agreement, Senior Unsecured Notes, Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios (such as collateral coverage, interest coverage and consolidated leverage), the maintenance of minimum net worth and working capital and debt-to-equity requirements. As of September 30, 2010 and December 31, 2009, we were in compliance with all of our debt covenants and restrictions.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, 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.

The Credit Agreement and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan with all or a portion of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans.

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 consolidated condensed balance sheet. No conversion triggers were met during any period covered in this Quarterly Report on Form 10-Q.

We amended our Credit Agreement in October 2009 and again in February 2010. In October 2009 the Credit Agreement was amended to, among other things, extend its maturity from July 2011 to November 2012. In February 2010, the Credit Agreement was once again amended, to among other things, modify the consolidated leverage ratio test and to include an additional senior secured debt leverage ratio test for periods beginning on or after March 31, 2010. See Note 9 for additional information related to our long-term debt, including more information regarding the recent amendments of our Credit Agreement and our requirements and obligations under the debt agreements including our covenants and collateral security.

Working Capital

Cash flow from operating activities decreased by $189.4 million in the nine months ended September 30, 2010 compared to the same period in 2009. This decrease includes the effect of recognizing $73.5 million of previously disputed cash royalty payments that we had been deferring until January 2009 (Note 6), the deconsolidation of Cal Dive in June 2009 (Note 4), the receipt of insurance proceeds associated with the settlement of our Hurricane Ike claims (Note 6), our increased internal utilization of vessels for developing our oil and gas properties in the first three months of 2010, and a decrease in our working capital cash flows.

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of dynamically positioned vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the nine-month periods ended September 30, 2010 and 2009 were as follows:

	Nine Months Ended September 30,	
	2010	**2009**
	(in thousands)	
Capital expenditures:		
Contracting Services	$ (50,663)	$ (149,872)
Shelf Contracting	—	(39,569)
Production Facilities[1]	(47,726)	(24,502)
Oil and Gas[1]	(64,523)	(92,209)
Investments in equity investments	—	(551)
Distributions from equity investments, net[2]	2,108	4,774
Proceeds from sale of properties and other	719	349,270
Cash (used in) provided by investing activities	$ (160,085)	$ 47,341

(1) Amounts net of insurance recovery ($7.0 million for Production Facilities and $9.1 million for oil and gas). This insurance recovery is related to damage sustained to the Phoenix field in 2005, which we remediated upon our acquisition of the field.
(2) 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 September 30, 2010 and December 31, 2009, we had $35.3 million and $35.4 million of restricted cash, all of which related to the funds contractually required to be escrowed to cover the asset retirement obligations associated with the South Marsh Island Block 130 field. We have fully satisfied our escrow requirements and may use the restricted cash for the future asset retirement costs for this field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

Equity Investments

Our net investment in the recently formed CloughHelix JV (Note 8) totaled $2.8 million at September 30, 2010, which includes equity contributions of $7.8 million less our $5.0 million share of the loss for the joint venture for the nine-month period ended September 30, 2010. Our investment in the CloughHelix JV is in the form of a loan, which is a fixed non-interest bearing with no stated maturity. We did not make any equity investments during the nine-months period ended September 30, 2009. We received the following distributions from our equity investments during the nine-month periods ended September 30, 2010 and 2009:

	Nine Months Ended September 30,	
	2010	2009
	(in thousands)	
Deepwater Gateway.	$ 6,125	$ 4,500
Independence	16,415	20,000
Total	$ 22,540	$ 24,500

Sale of Oil and Gas Properties

In the first quarter of 2009, we sold our remaining 10% interest in the Bass Lite field for $4.5 million and our interest 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.

New Reclamation Requirements

On September 15, 2010, BOEMRE issued Notice to Lessees (NTL) 2010-G05 with an effective date of October 15, 2010. The NTL continues the previously mandated timeframe for decommissioning structures (platforms and pipelines) and wells on terminated leases, which requires the lessee to commence reclamation activities within 12 months following the termination of any federal lease. The new requirements of the NTL mandate that leaseholders of active oil and gas leases submit plans to abandon wells and structures that have been inactive over the past five years. These types of structures are commonly referred to as “idle iron” within the industry. Pursuant to the new regulation operators of properties with idle iron must submit plans to BOEMRE that address the removal of dormant structures within the next five years and dormant wells over the next three years . This new mandate may have the effect of accelerating the timing of certain reclamation activities at some of our oil and gas fields. We are evaluating the potential impact of this NTL on our oil and gas properties and expect to complete this assessment by year-end 2010. At this time, we do not believe this NTL will materially affect our results of operations or our consolidated financial position.

Outlook

We anticipate that the total amount of our incurred capital expenditures for 2010 will approximate $200 million. The estimates for these capital expenditures may increase or decrease based on various economic factors. We believe internally generated cash flow, cash from future sales of our non-core business assets, and borrowings under our existing credit facilities will provide the capital necessary to fund our remaining 2010 initiatives as well as those in 2011.

The following table summarizes our contractual cash obligations as of September 30, 2010 and the scheduled years in which the obligations are contractually due:

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
Convertible Senior Notes(2)	$ 300,000	$ —	$ —	$ —	$ 300,000
Senior Unsecured Notes	550,000	—	—	—	550,000
Term Loan	411,522	4,326	407,196	—	—
MARAD debt	114,811	4,645	9,997	11,020	89,149
Revolving Credit Facility	—	—	—	—	—
Loan notes	1,874	1,874	—	—	—
Interest related to long-term debt	516,271	84,784	159,358	135,110	137,019
Drilling and development costs	17,191	17,191	—	—	—
Property and equipment	6,410	6,410	—	—	—
Operating leases(3)	78,092	47,157	28,406	2,529	—
Total cash obligations	$ 1,996,171	$ 166,387	$ 604,957	$ 148,659	$ 1,076,168

(1) Excludes unsecured letters of credit outstanding at September 30, 2010 totaling $61.2 million. These letters of credit primarily guarantee various contract bidding, contractual obligations and insurance activities.

(2) Contractual maturity in 2025 (Notes can be redeemed by us or we may be required to purchase them beginning in December 2012). Notes can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At September 30, 2010, the conversion trigger was not met. If the Convertible Senior Notes are converted in 2012 the amount due in 1-3 years would increase from the approximate $605 million shown in the table to approximately $905 million.

(3) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2010 were approximately $66.5 million.

Contingencies

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. Under the terms of the contract, our potential liability for damages was generally capped at approximately $32 million Australian dollars ("AUD"). We asserted a counterclaim that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. Under terms of the settlement, in April 2010 we paid the third party $15 million AUD to settle all its damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our accompanying condensed consolidated statement of operations for the nine-month period ended September 30, 2010 includes approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. The charges were recorded as a component of our general and administrative expenses.

In 2008, we were subcontracted by the prime contractor to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2008 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivable and claims yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor then arbitration in India remains a potential remedy. Based on number of factors associated with the ongoing negotiations with the prime contractor, at September 30, 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable. However, at the time of this filing no commercial resolution of this matter has been reached and we are continuing to actively pursue collection of the full balance of our trade receivable and our other claims.

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

We are currently involved in a large project located offshore China in which we are abandoning a number of wells utilizing our repaired subsea intervention device ("SID"), which was out of service since early 2009. The SID was installed on the *Normand Clough*, a vessel chartered through our CloughHelix J V. Even though we anticipated that abandonment of the wells would be challenging, the work has proven somewhat more difficult than initially contemplated both from a structural standpoint and because of certain start up issues related to the repaired SID. Further complicating the project is the fact that typhoon season is in effect and we have lost a number of days due to weather. We now estimate that this job will no longer be profitable. In accordance with ASC No. 605-35 "*Construction Type and Production Type Contracts*" we have estimated the shortfall between the future revenues and future costs associated with the project. The current estimate of the loss on this contract is $8.5 million, which was recorded in our results of operations for the three-month period ended September 30, 2010. This estimate is subject to change pending actual completion of the project which is expected to occur in the fourth quarter of 2010.

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 2009 Form 10-K.

RECENT ACCOUNTING STANDARDS

In January 2010, the Financial Accounting Standard Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06, "*Improving Disclosures about Fair Value Measurements*" an amendment to ASC Topic 820. This amendment requires an entity to: (i) disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reason for the transfers and (ii) present separate information for Level 3 activity pertaining to gross purchases, sales, issuances, and settlements. This amendment is effective interim and annual reporting periods beginning after December 15, 2009. We adopted this ASU effective January 1, 2010.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Commodity Price Risk. As of September 30, 2010, we have the following volumes under derivative contracts related to our oil and gas production totaling approximately 3.3 MMBbl of oil and 14.2 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes		Weighted Average Price
Crude Oil:				(per barrel)
October 2010 — December 2010	Collar	100	MBbl	$62.50-$80.73
October 2010 — December 2010	Swap	105	MBbl	$76.55
October 2010 — December 2010	Swap	107	MBbl	$81.39
January 2011 — December 2011	Swap	198	MBbl	$81.31
Natural Gas:				(per Mcf)
October 2010 — December 2010	Swap	1,020	Mmcf	$5.81
October 2010 — December 2010	Collar	1,012	Mmcf	$6.00 — $6.70
January 2011 — December 2011	Swap	675	Mmcf	$5.09

Until June 2010 all of our oil and gas commodity contracts for expected 2010 production qualified for hedge accounting. In June 2010 some of our oil contracts for 480 MBbl covering portions of our anticipated production during the third quarter of 2010 ceased to qualify for hedge accounting as a result of our decision to contract the *HP I* to BP to assist in the oil spill containment response rather than commencing production from our Phoenix field. In September 2010, we concluded that oil contracts for covering 480 MBbls of the fourth quarter 2010 anticipated production ceased to qualify for hedge accounting because of uncertainty as to when the Phoenix field would be ready to commence initial production following extensions of the *HP I* contract to assist BP in the oil spill containment response. The *HP I* returned to the Phoenix field in October and initial production from the field commenced on October 19, 2010. All of our remaining commodity derivative contracts are designated as cash flow hedges remain effective and qualify for hedge accounting as of September 30, 2010 (Note 18). The amount of ineffectiveness related to our oil and gas commodity contracts was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended September 30, 2010. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 2010 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended September 30, 2010.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 16 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the risk factors set forth below and the other information set forth in this quarterly report on Form 10-Q, careful consideration should be given to factors described in "Item 1A. Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2009 and subsequent Quarterly Reports on Form 10-Q that could materially affect our business, financial condition or future results

The *Deepwater Horizon* drilling rig explosion in the Gulf of Mexico, the subsequent oil spill and the resulting enhanced regulations for deepwater drilling offshore the United States may impact our oil and gas business located offshore in the Gulf of Mexico and reduce the need for our services in the Gulf of Mexico.

In April 2010, the *Deepwater Horizon* drilling rig experienced an explosion and fire, and later sank into the Gulf of Mexico. The complete destruction of the *Deepwater Horizon* rig also resulted in a significant release of crude oil into the Gulf. As a result of this explosion, the resulting oil spill and the inability to stop the oil spill, a moratorium was placed on offshore deepwater drilling in the United States, which was subsequently lifted on October 12, 2010 and replaced with enhanced safety standards for offshore deepwater drilling. Under the enhanced safety standards, in order for an operator to resume deepwater drilling, it is required to comply with existing and newly developed regulations and standards, including Notice to Lessees (NTL), 2010-N05 (Safety NTL), NTL 2010-N06 (Environmental NTL) and the Interim Final Rule (Drilling Safety Rule). BOEMRE also plans to conduct inspections of each deepwater drilling operation for compliance with BOEMRE's regulations, including but not limited to the testing of blow out preventers, before drilling resumes. As companies resume operations, they will also need to comply with the Workplace Safety Rule (SEMS Rule) within the deadlines specified by the regulation. Additionally, each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. The Department of the Interior has a process underway regarding the establishment of a mechanism relating to the availability of blowout containment resources, and it is expected that this mechanism will be implemented in the near future. It is also expected that the BOEMRE will issue further regulations regarding deepwater offshore drilling. Our contracting services business, a significant portion of which is in the Gulf of Mexico, provides development services to newly-drilled wells, and therefore relies heavily on the industry's drilling of new oil and gas wells. In addition, growth in our oil and gas business and any potential disposition of that business will be affected by the ability to develop our portfolio of prospects. Although the moratorium has been lifted, to date no new permits for offshore deepwater drilling have been issued. We can provide no assurance regarding the grant or timing of permits. If permits are not issued or there is a significant delay in issuance, and with respect to our services business, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations could be materially affected.

The potential increased costs of complying with new regulations on offshore drilling in the U.S. Gulf of Mexico following the *Deepwater Horizon* rig explosion and potentially in other areas around the world, may impact our oil and gas business and reduce the need for our services in those areas.

The *Deepwater Horizon* rig explosion in the Gulf of Mexico and its aftermath has resulted in legislation and regulation in the United States, which may result in substantial increases in costs or delays in drilling or other operations in the Gulf of Mexico, oil and gas projects becoming potentially non-economic, and a corresponding reduced demand for our services. We cannot predict with any certainty the substance or effect of any new or additional regulations in the United States or in other areas around the world. In addition, safety requirements or other governmental regulations could increase our costs of operation of our oil and gas business and impact our ability to divest the assets of that business. Likewise this could also result in increased costs of operating our contracting services business, and our potential consumers' oil and gas projects becoming non-economic, which could also negatively affect the demand for our contracting services business. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling or contracting services operations, our business, financial condition and results of operations could be materially affected.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum value of shares that may yet be purchased under the program
July 1 to July 31, 2010(1)	223,487	$ 11.21	223,487	—
August 1 to August 31, 2010(1)	—	—	—	—
September 1 to September 30, 2010(1)	2,481	9.53	—	—
	225,968	$ 11.19	223,487	—

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

(2) Shares repurchased under previously announced stock buyback program (Note 19). The remaining shares currently available under the share plan were purchased in early July 2010. There are currently no shares available for repurchase under our share plan.

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.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter(1)
23.1	Consent of Huddleston & Co., Inc. (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)
99.2	Report of Huddleston & Co. Inc., incorporated by reference to Exhibit 99.2 to the Quarterly Report on Form 10-Q filed by the registrant with the Securities and Exchange Commission on July 30, 2010.
	(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: October 28, 2010	By: **/s/ Owen Kratz**
	Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: October 28, 2010	By: **/s/ Anthony Tripodo**
	Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

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	(1) Filed herewith
	(2) Furnished herewith

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EXHIBIT 15.1

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S
ACKNOWLEDGEMENT LETTER

October 28, 2010

To the Board of Directors and Shareholders
of Helix Energy Solutions Group, Inc.

We are aware of the incorporation by reference in Registration Statement Forms S-3 (Nos. 333-157785, 333-103451 and 333-125276) and Forms S-8 (Nos. 333-126248, 333-58817, 333-50289 and 333-50205) of Helix Energy Solutions Group, Inc. of our report dated October 28, 2010 relating to the unaudited condensed consolidated interim financial statements of Helix Energy Solutions Group, Inc. and subsidiaries that are included in its Form 10-Q for the quarter ended September 30, 2010.

Very truly yours,

/s/ ERNST & YOUNG LLP

Houston, Texas

EXHIBIT 23.1

[Huddleston Letterhead]

October 28, 2010

Helix Energy Solutions Group, Inc.
400 North Sam Houston Parkway East
Suite 400
Houston, Texas 77060

Re: Helix Energy Solutions Group, Inc.
Securities and Exchange Commission
Form 10-Q
Consent Letter

Gentlemen:

The firm of Huddleston & Co., Inc. consents to the use of our reserve report letter dated July 19, 2010 relating to the proved reserves of oil and gas attributable to Energy Resource Technology GOM, Inc. as of July 1, 2010 to be incorporated by reference into the Helix Energy Solutions Group, Inc. Quarterly Report on Form 10-Q for the period ending September 30, 2010 to be filed with the Securities and Exchange Commission.

Huddleston & Co., Inc. has no interests in Helix Energy Solutions Group, Inc. or in any of its affiliated companies or subsidiaries and is not to receive any such interest as payment for such report and has no director, officer, or employee employed or otherwise connected with Helix Energy Solutions Group, Inc. We are not employed by Helix Energy Solutions Group, Inc. on a contingent basis.

Very truly yours,

HUDDLESTON & CO., INC.
Texas Registered Engineering Firm F-1024

By: /s/ Peter D. Huddleston

-
Name: Peter D. Huddleston, P.E.
Title: President

EXHIBIT 31.1

SECTION 302 CERTIFICATION

I, Owen Kratz, the President and Chief Executive Officer of Helix Energy Solutions Group, Inc., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Helix Energy Solutions Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 28, 2010

/s/ Owen Kratz
Owen Kratz
President and Chief Executive Officer

EXHIBIT 31.2

SECTION 302 CERTIFICATION

I, Anthony Tripodo, the Executive Vice President and Chief Financial Officer of Helix Energy Solutions Group, Inc., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Helix Energy Solutions Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 28, 2010

/s/ Anthony Tripodo
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO PURSUANT TO 18 U.S.C. SECTION 1350
(Adopted Pursuant to Section 906 of Sarbanes-Oxley Act of 2002)

Pursuant to section 1350 of chapter 63 of title 18 of the United States Code, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Owen Kratz, as President and Chief Executive Officer, and Anthony Tripodo, as Executive Vice President and Chief Financial Officer, each hereby certifies that the Quarterly Report of Helix Energy Solutions Group, Inc. (“Helix”) on Form 10-Q for the period ended September 30, 2010, as filed with the Securities and Exchange Commission on the date hereof (the “Report”):

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Helix.

Date: October 28, 2010

/s/ Owen Kratz
Owen Kratz
President and Chief Executive Officer

Date: October 28, 2010

/s/ Anthony Tripodo
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Helix and will be retained by Helix and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

EXHIBIT 99.1

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc.

We have reviewed the condensed consolidated balance sheet of Helix Energy Solutions Group, Inc. and subsidiaries as of September 30, 2010, and the related condensed consolidated statements of operations for the three-month and nine-month periods ended September 30, 2010 and 2009, and the condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2010 and 2009. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated February 26, 2010, we expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph for the adoption of a new accounting standard related to non-controlling interests and new oil and gas reserve estimation and disclosure requirements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2009, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Houston, Texas
October 28, 2010