HERCULES OFFSHORE, INC.
Form 10-Q
August 03, 2010

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

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2010

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 0-51582

HERCULES OFFSHORE, INC.
(Exact name of registrant as specified in its charter)

Delaware	**56-2542838**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9 Greenway Plaza, Suite 2200 Houston, Texas	**77046**
(Address of principal executive offices)	**(Zip Code)**

(713) 350-5100
(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES o NO o

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES o NO þ

Indicate the number of shares outstanding of each of the issuer s classes of common stock as of the latest practicable date.

Common Stock, par value $0.01 per share	Outstanding as of July 23, 2010
	114,772,344

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except par value)

	June 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 91,724	$ 140,828
Restricted Cash	7,029	3,658
Accounts Receivable, Net of Allowance for Doubtful Accounts of $33,019 and $38,522 as of June 30, 2010 and December 31, 2009, Respectively	161,488	133,662
Prepaids	28,313	13,706
Current Deferred Tax Asset	12,195	22,885
Other	21,067	6,675
	321,816	321,414
Property and Equipment, Net	1,841,652	1,923,603
Other Assets, Net	29,756	32,459
	$ 2,193,224	$ 2,277,476
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 4,924	$ 4,952
Insurance Notes Payable	21,930	5,484
Accounts Payable	50,803	51,868
Accrued Liabilities	52,949	67,773
Interest Payable	14,756	6,624
Taxes Payable		5,671
Other Current Liabilities	30,895	34,229
	176,257	176,601
Long-term Debt, Net of Current Portion	854,778	856,755
Other Liabilities	8,302	19,809
Deferred Income Taxes	205,283	245,799
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 Par Value; 200,000 Shares Authorized; 116,308 and 116,154 Shares Issued, Respectively; 114,762 and 114,650 Shares Outstanding, Respectively	1,163	1,162
Capital in Excess of Par Value	1,922,226	1,921,037
Treasury Stock, at Cost, 1,546 Shares and 1,504 Shares, Respectively	(50,320)	(50,151)
Accumulated Other Comprehensive Loss	(1,762)	(5,773)
Retained Deficit	(922,703)	(887,763)

	948,604	978,512
	$ 2,193,224	$ 2,277,476

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Revenues	$ 165,895	$ 183,691	$ 316,744	$ 407,182
Costs and Expenses:				
Operating Expenses	108,321	116,097	216,957	265,341
Impairment of Property and Equipment		26,882		26,882
Depreciation and Amortization	48,350	51,091	98,604	99,937
General and Administrative	14,798	15,450	27,101	31,742
	171,469	209,520	342,662	423,902
Operating Loss	(5,574)	(25,829)	(25,918)	(16,720)
Other Income (Expense):				
Interest Expense	(21,259)	(14,561)	(42,998)	(30,350)
Gain on Early Retirement of Debt, Net		13,747		13,747
Other, Net	3,183	3,346	3,169	2,690
Loss Before Income Taxes	(23,650)	(23,297)	(65,747)	(30,633)
Income Tax Benefit	4,666	11,510	30,807	14,335
Loss from Continuing Operations	(18,984)	(11,787)	(34,940)	(16,298)
Loss from Discontinued Operation, Net of Taxes		(242)		(675)
Net Loss	$ (18,984)	$ (12,029)	$ (34,940)	$ (16,973)
Basic Loss Per Share:				
Loss from Continuing Operations	$ (0.17)	$ (0.13)	$ (0.30)	$ (0.18)
Loss from Discontinued Operation		(0.01)		(0.01)
Net Loss	$ (0.17)	$ (0.14)	$ (0.30)	$ (0.19)
Diluted Loss Per Share:				
Loss from Continuing Operations	$ (0.17)	$ (0.13)	$ (0.30)	$ (0.18)
Loss from Discontinued Operation		(0.01)		(0.01)
Net Loss	$ (0.17)	$ (0.14)	$ (0.30)	$ (0.19)
Weighted Average Shares Outstanding:				
Basic	114,757	88,733	114,727	88,368
Diluted	114,757	88,733	114,727	88,368

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash Flows from Operating Activities:		
Net Loss	$ (34,940)	$ (16,973)
Adjustments to Reconcile Net Loss to Net Cash Provided by (Used In) Operating Activities:		
Depreciation and Amortization	98,604	99,937
Stock-Based Compensation Expense	1,817	4,115
Deferred Income Taxes	(32,311)	(25,063)
Provision (Benefit) for Doubtful Accounts Receivable	(1,771)	543
Amortization of Deferred Financing Fees	1,683	2,096
Amortization of Original Issue Discount	1,998	2,386
Non-Cash Loss on Derivatives	2,835	
Gain on Insurance Settlement		(8,700)
Gain on Disposal of Assets	(6,729)	(332)
Gain on Early Retirement of Debt, Net		(13,747)
Impairment of Property and Equipment		26,882
Excess Tax Benefits from Stock-Based Arrangements	(377)	(5,031)
(Increase) Decrease in Operating Assets -		
Accounts Receivable	(26,055)	64,738
Prepaid Expenses and Other	13,027	8,383
Increase (Decrease) in Operating Liabilities -		
Accounts Payable	(1,065)	(31,542)
Insurance Notes Payable	(7,669)	(13,236)
Other Current Liabilities	(30,370)	(5,010)
Other Liabilities	(12,175)	(1,946)
Net Cash Provided by (Used In) Operating Activities	(33,498)	87,500
Cash Flows from Investing Activities:		
Additions of Property and Equipment	(11,015)	(62,068)
Deferred Drydocking Expenditures	(7,574)	(9,662)
Insurance Proceeds Received		8,717
Proceeds from Sale of Assets, Net	9,969	4,722
Increase in Restricted Cash	(3,371)	
Net Cash Used in Investing Activities	(11,991)	(58,291)
Cash Flows from Financing Activities:		
Short-term Debt Repayments		(2,455)
Long-term Debt Repayments	(4,003)	(2,250)
Redemption of 3.375% Convertible Senior Notes		(6,099)
Excess Tax Benefits from Stock-Based Arrangements	377	5,031
Other	11	(11)
Net Cash Used in Financing Activities	(3,615)	(5,784)

Net Increase (Decrease) in Cash and Cash Equivalents	(49,104)	23,425
Cash and Cash Equivalents at Beginning of Period	140,828	106,455
Cash and Cash Equivalents at End of Period	$ 91,724	$ 129,880

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(In thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net Loss	$ (18,984)	$ (12,029)	$ (34,940)	$ (16,973)
Other Comprehensive Income, Net of Taxes:				
Changes Related to Hedge Transactions	1,932	1,988	4,011	1,582
Comprehensive Loss	$ (17,052)	$ (10,041)	$ (30,929)	$ (15,391)

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
UNAUDITED

1. General

Hercules Offshore, Inc., a Delaware corporation, and its majority owned subsidiaries (the Company) provide shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally through its Domestic Offshore, International Offshore, Inland, Domestic Liftboats, International Liftboats and Delta Towing segments (See Note 10). At June 30, 2010, the Company owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels operated through Delta Towing, a wholly owned subsidiary, and 60 liftboat vessels and operated an additional five liftboat vessels owned by a third party. In addition, the Company currently owns three retired jackup rigs and two retired inland barges, all located in the U.S. Gulf of Mexico, which are currently not expected to re-enter active service. The Company s diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection, maintenance and decommissioning operations in several key shallow water provinces around the world.

The consolidated financial statements of the Company are unaudited; however, they include all adjustments of a normal recurring nature which, in the opinion of management, are necessary to present fairly the Company s Consolidated Balance Sheet at June 30, 2010, Consolidated Statements of Operations and Consolidated Statements of Comprehensive Loss for the three and six months ended June 30, 2010 and 2009, and Consolidated Statements of Cash Flows for the six months ended June 30, 2010 and 2009. Although the Company believes the disclosures in these financial statements are adequate to make the interim information presented not misleading, certain information relating to the Company s organization and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles have been condensed or omitted in this Form 10-Q pursuant to Securities and Exchange Commission rules and regulations. These financial statements should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2009 and the notes thereto included in the Company s Annual Report on Form 10-K. The results of operations for the three and six months ended June 30, 2010 are not necessarily indicative of the results expected for the full year.

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, the Company evaluates its estimates, including those related to bad debts, investments, intangible assets, property and equipment, income taxes, insurance, employment benefits and contingent liabilities. The Company bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

In December 2009, the Company entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby it would market, manage and operate two Friede & Goldman Super M2 design, new-build jackup drilling rigs each with a maximum water depth of 300 feet. The rigs are currently under construction and one is scheduled to be delivered in each of the fourth quarter of 2010 and the first quarter of 2011. The Company is actively marketing the rigs globally on an exclusive basis.

In January 2010, the Company entered into an agreement with SKDP 1 Ltd., an affiliate of Skeie Drilling & Production ASA, to market, manage and operate an ultra high specification KFELS Class N new-build jackup drilling rig with a maximum water depth of 400 feet. The agreement was limited to a specified opportunity in the Middle East and expired by its terms during the second quarter when the rig was not selected by the operator.

Reclassifications

Certain reclassifications have been made to conform prior year financial information to the current period presentation.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

Revenue Recognition

Revenues generated from our contracts are recognized as services are performed, as long as collectability is reasonably assured. For certain contracts, the Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another under contracts longer than ninety days are recognized as services are performed over the term of the related drilling contract. Amounts related to mobilization fees are summarized below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Mobilization revenue deferred	$	$	$ 600	$12,000
Mobilization expense deferred				132
Mobilization revenue recognized	4,134	4,233	7,911	8,149
Mobilization expense recognized	676	700	1,592	1,393

For certain contracts, the Company may receive fees from its customers for capital improvements to its rigs. Such fees are deferred and recognized as services are performed over the term of the related contract. The Company capitalizes such capital improvements and depreciates them over the useful life of the asset.

The balances related to the Company s Deferred Mobilization and Contract Preparation Costs and Deferred Mobilization Revenue are as follows (in thousands):

	Balance Sheet Classification	As of June 30, 2010	As of December 31, 2009
Assets:			
Deferred Mobilization and Contract Preparation Expense-Current Portion	Other	$ 959	$ 1,092
Deferred Mobilization and Contract Preparation Expense-Non-Current Portion	Other Assets, Net	23	1,651
Liabilities:			
Deferred Mobilization Revenue-Current Portion	Other Current Liabilities	18,910	19,406
Deferred Mobilization Revenue-Non-Current Portion	Other Liabilities	3,502	12,628

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for doubtful accounts. Management of the Company monitors the accounts receivable from its customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance. The Company had an allowance of $33.0 million and $38.5 million at June 30, 2010 and December 31, 2009, respectively.

Other Assets

Other assets consist of drydocking costs for marine vessels, other intangible assets, deferred income taxes, deferred costs, financing fees, investments, deposits and other. Drydocking costs are capitalized at cost and amortized on the straight-line method over a period of 12 months. Drydocking costs, net of accumulated amortization, at both June 30, 2010 and December 31, 2009, were $4.9 million. Amortization expense for drydocking costs was $3.4 million and $7.6 million for the three and six months ended June 30, 2010, respectively and $4.8 million and $8.6 million for the three and six months ended June 30, 2009, respectively.

Financing fees are deferred and amortized over the life of the applicable debt instrument. However, in the event of an early repayment of debt, the related unamortized deferred financing fees are expensed in connection with the repayment. Unamortized deferred financing fees at June 30, 2010 and December 31, 2009 were $13.0 million and $14.7 million, respectively. The amortization

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

expense related to the deferred financing fees is included in Interest Expense on the Consolidated Statements of Operations. Amortization expense for financing fees was $0.8 million and $1.7 million for the three and six months ended June 30, 2010, respectively and $1.0 million and $2.1 million for the three and six months ended June 30, 2009, respectively. In addition, the Company recognized a pretax charge of $1.4 million during the second quarter of 2009 related to the write off of unamortized issuance costs related to its 3.375% Convertible Senior Notes in connection with the April 2009 debt repurchase and the June 2009 debt retirement (See Note 4).

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits with banks and all highly liquid investments with original maturities of three months or less.

Restricted Cash

At June 30, 2010 and December 31, 2009, the Company had restricted cash of $7.0 million and $3.7 million to support surety bonds primarily related to the Company s Mexico and U.S. operations. In July 2010, the Company increased its restricted cash balance by $6.1 million as additional collateral to support surety bonds related to its Mexico and U.S. operations (See Note 13).

2. Earnings Per Share

The Company calculates basic earnings per share by dividing net income by the weighted average number of shares outstanding. Diluted earnings per share is computed by dividing net income by the weighted average number of shares outstanding during the period as adjusted for the dilutive effect of the Company s stock option and restricted stock awards. The effect of stock option and restricted stock awards is not included in the computation for periods in which a net loss occurs, because to do so would be anti-dilutive. Stock equivalents of 6,564,611 and 6,006,817 were anti-dilutive and are excluded from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the three and six months ended June 30, 2010, respectively. Stock equivalents of 4,826,061 and 4,343,526 were anti-dilutive and are excluded from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the three and six months ended June 30, 2009, respectively.

3. Dispositions

In December 2009, the Company entered into an agreement to sell its retired jackups *Hercules 191* and *Hercules 255* for $5.0 million each. The sale of the *Hercules 191* was completed in April 2010 for gross proceeds of $5.0 million, resulting in a gain of $3.1 million. The sale of the *Hercules 255* is expected to close in the third quarter of 2010. In February 2010, the Company entered into an agreement to sell six of its retired barges for $3.0 million of which $2.2 million in gross proceeds was received during the first quarter of 2010 for the completion of the sale of three of the six barges resulting in a net gain of $1.8 million. The sale of the remaining three barges was completed in April 2010 for gross proceeds of $0.8 million resulting in a gain of $0.4 million. Additionally, in July 2010, the Company entered into an agreement to sell retired jackup *Hercules 155* for $4.8 million (See Note 13).

In June 2009, the Company entered into an agreement to sell its *Hercules 100* and *Hercules 110* jackup drilling rigs for a total purchase price of $12.0 million. *Hercules 100* was classified as retired and was stacked in Sabine Pass, Texas, and *Hercules 110* was cold-stacked in Trinidad. The closing of the sale of *Hercules 100* and *Hercules 110* occurred in August 2009 and the net proceeds of $11.8 million from the sale were used to repay a portion of the Company s term loan facility. The Company realized approximately $26.9 million ($13.1 million, net of tax) of impairment charges related to the write-down of *Hercules 110* to fair value less costs to sell during the second quarter of 2009 (See Note 6). The financial information for *Hercules 100* has historically been reported as part of the Domestic Offshore Segment and *Hercules 110* financial information has been reported as part of the International Offshore Segment.

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

4. Debt

Debt is comprised of the following (in thousands):

	June 30, 2010	December 31, 2009
Term Loan Facility, due July 2013	$ 478,849	$ 482,852
10.5% Senior Secured Notes, due October 2017	292,595	292,272
3.375% Convertible Senior Notes, due June 2038	84,746	83,071
7.375% Senior Notes, due April 2018	3,512	3,512
Total Debt	859,702	861,707
Less Short-term Debt and Current Portion of Long-term Debt	4,924	4,952
Total Long-term Debt, Net of Current Portion	$ 854,778	$ 856,755

Senior secured credit facility

The Company has a $653.8 million credit facility, consisting of a $478.8 million term loan facility and a $175.0 million revolving credit facility. The availability under the $175.0 million revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay the term loan. Under the credit agreement which governs the credit facility (the Credit Agreement), the Company must comply with the following:

The total leverage ratio for any test period is calculated as the ratio of consolidated indebtedness on the test date to consolidated EBITDA for the trailing twelve months, all as defined in the Credit Agreement.

Test Date	Maximum Total Leverage Ratio
September 30, 2010	8.00 to 1.00
December 31, 2010	7.50 to 1.00
March 31, 2011	7.00 to 1.00
June 30, 2011	6.75 to 1.00
September 30, 2011	6.00 to 1.00
December 31, 2011	5.50 to 1.00
March 31, 2012	5.25 to 1.00
June 30, 2012	5.00 to 1.00
September 30, 2012	4.75 to 1.00
December 31, 2012	4.50 to 1.00
March 31, 2013	4.25 to 1.00
June 30, 2013	4.00 to 1.00

- At June 30, 2010, the Company s total leverage ratio was 8.09. There is no maximum total leverage requirement for the period ended June 30, 2010.

Maintain a minimum level of liquidity, measured as the amount of unrestricted cash and cash equivalents on hand and availability under the revolving credit facility, of (i) $100.0 million for the period between October 1, 2009 through December 31, 2010, (ii) $75.0 million during calendar year 2011 and (iii) $50.0 million thereafter. As of June 30, 2010, as calculated pursuant to the Credit Agreement, the Company s total liquidity was $256.7 million.

Maintain a minimum fixed charge coverage ratio as follows:

Period		**Fixed Charge Coverage Ratio**
July 1, 2009	December 31, 2011	1.00 to 1.00
January 1, 2012	March 31, 2012	1.05 to 1.00
April 1, 2012	June 30, 2012	1.10 to 1.00
July 1, 2012 and thereafter		1.15 to 1.00

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

- The consolidated fixed charge coverage ratio for any test period is defined as the sum of consolidated EBITDA for the test period plus an amount that may be added for the purpose of calculating the ratio for such test period, not to exceed $130.0 million in total during the term of the credit facility, to consolidated fixed charges for the test period, all as defined in the Credit Agreement. As of June 30, 2010, the Company s fixed charge coverage ratio was 1.0.

Mandatory prepayments of debt outstanding under the Credit Agreement with 50% of excess cash flow as defined in the Credit Agreement for the fiscal years ending December 31, 2010, 2011 and 2012, and with proceeds from:

- unsecured debt issuances, with the exception of refinancing;
- secured debt issuances;
- casualty events not used to repair damaged property;
- sales of assets in excess of $25 million annually; and

The Company s obligations under the Credit Agreement are secured by liens on a majority of its vessels and substantially all of its other personal property. Substantially all of the Company s domestic subsidiaries, and several of its international subsidiaries, guarantee the obligations under the Credit Agreement and have granted similar liens on several of their vessels and substantially all of their other personal property.

Other covenants contained in the Credit Agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, stock repurchases and redemptions, other restricted payments, debt issuances, liens, investments, convertible notes repurchases and affiliate transactions. The Credit Agreement also contains a provision under which an event of default on any other indebtedness exceeding $25.0 million would be considered an event of default under the Company s Credit Agreement.

The Credit Agreement requires that the Company meet certain financial ratios and tests, which it met as of June 30, 2010. The Company s failure to comply with such covenants would result in an event of default under the Credit Agreement. An event of default could prevent the Company from borrowing under the revolving credit facility, which would in turn have a material adverse effect on the Company s available liquidity. Additionally, an event of default could result in the Company having to immediately repay all amounts outstanding under the credit facility, the 10.5% Senior Secured Notes and the 3.375% Convertible Senior Notes and in the foreclosure of liens on its assets.

As of June 30, 2010, no amounts were outstanding and $10.0 million in stand-by letters of credit had been issued under the revolving credit facility, therefore the remaining availability under this revolving credit facility was $165.0 million. Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.2 million, with the balance due on July 11, 2013. All borrowings under the revolving credit facility mature on July 11, 2012. Interest payments on both the revolving and term loan facility are due at least on a quarterly basis and in certain instances, more frequently. As of June 30, 2010, $478.8 million was outstanding on the term loan facility and the interest rate was 6.00%. The annualized effective interest rate was 9.07% for the six months ended June 30, 2010 after giving consideration to revolver fees and derivative activity.

10.5% senior secured notes due 2017

The notional amount of the 10.5% Senior Secured Notes, its unamortized discount and its net carrying amount was $300.0 million, $7.4 million and $292.6 million, respectively, as of June 30, 2010 and $300.0 million, $7.7 million and $292.3 million, respectively, as of December 31, 2009. The unamortized discount is being amortized to interest expense over the life of the 10.5% Senior Secured Notes which ends in October 2017. During the three months ended June 30, 2010, the Company recognized $8.0 million, $5.2 million, net of tax, in interest expense, or $0.05 per diluted share, at an effective rate of 11%, of which $7.8 million related to the coupon rate of 10.5% and $0.2 million related to discount amortization. During the six months ended June 30, 2010, the Company recognized $16.0 million, $10.4 million, net of tax, in interest expense, or $0.09 per diluted share, at an effective rate of 11%, of which $15.7 million related to the coupon rate of 10.5% and $0.3 million related to discount amortization. There was no interest expense recognized during the three or six months ended June 30, 2009 as the 10.5% Senior Secured Notes were issued in October 2009.

The notes are guaranteed by all of the Company s existing and future restricted subsidiaries that incur or guarantee indebtedness under a credit facility, including the Company s existing credit facility. The notes are secured by liens on all collateral that secures the Company s obligations under its secured credit facility, subject to limited exceptions. The liens securing the notes share on an equal

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

and ratable first priority basis with liens securing the Company s credit facility. Under the intercreditor agreement, the collateral agent for the lenders under the Company s secured credit facility is generally entitled to sole control of all decisions and actions.

All the liens securing the notes may be released if the Company s secured indebtedness, other than these notes, does not exceed the lesser of $375.0 million and 15.0% of our consolidated tangible assets. The Company refers to such a release as a collateral suspension. If a collateral suspension is in effect, the notes and the guarantees will be unsecured, and will effectively rank junior to our secured indebtedness. If, after any such release of liens on collateral, the aggregate principal amount of the Company s secured indebtedness, other than these notes, exceeds the greater of $375.0 million and 15.0% of its consolidated tangible assets, as defined in the indenture, then the collateral obligations of the Company and guarantors will be reinstated and must be complied with within 30 days of such event.

The indenture governing the notes contains covenants that, among other things, limit the Company s ability and the ability of its restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- make other restricted payments or investments;
- sell assets;
- create liens;
- enter into agreements that restrict dividends and other payments by restricted subsidiaries;
- engage in transactions with its affiliates; and
- consolidate, merge or transfer all or substantially all of its assets.

The indenture governing the notes also contains a provision under which an event of default by the Company or by any restricted subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default is: a) caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

Prior to October 15, 2012, the Company may redeem the notes with the net cash proceeds of certain equity offerings, at a redemption price equal to 110.50% of the aggregate principal amount plus accrued and unpaid interest; provided, that (i) after giving effect to any such redemption, at least 65% of the notes originally issued would remain outstanding immediately after such redemption and (ii) the Company makes such redemption not more than 90 days after the consummation of such equity offering. In addition, prior to October 15, 2013, the Company may redeem all or part of the notes at a price equal to 100% of the aggregate principal amount of notes to be redeemed, plus the applicable premium, as defined in the indenture, and accrued and unpaid interest.

On or after October 15, 2013, the Company may redeem the notes, in whole or part, at the redemption prices set forth below, together with accrued and unpaid interest to the redemption date.

Year	Optional Redemption Price
2013	105.2500%
2014	102.6250%
2015	101.3125%

2016 and thereafter	100.0000%

If the Company experiences a change of control, as defined, it must offer to repurchase the notes at an offer price in cash equal to 101% of their principal amount, plus accrued and unpaid interest. Furthermore, following certain asset sales, the Company may be required to use the proceeds to offer to repurchase the notes at an offer price in cash equal to 100% of their principal amount, plus accrued and unpaid interest.

3.375% convertible senior notes due 2038

The carrying amount of the equity component of the 3.375% Convertible Senior Notes was $30.1 million at both June 30, 2010 and December 31, 2009. The principal amount of the liability component of the 3.375% Convertible Senior Notes, its unamortized discount and its net carrying amount was $95.9 million, $11.2 million and $84.7 million, respectively, as of June 30, 2010 and $95.9 million, $12.8 million and $83.1 million, respectively, as of December 31, 2009. The unamortized discount is being amortized to interest expense over the expected life of the 3.375% Convertible Senior Notes which ends June 1, 2013. During the three months ended June 30, 2010, the Company recognized $1.6 million, $1.1 million, net of tax, in interest expense, or $0.01 per diluted share, at an effective rate of 7.93%, of which $0.8 million related to the coupon rate of 3.375% and $0.8 million related to discount amortization. During the six months ended June 30, 2010, the Company recognized $3.3 million, $2.1 million, net of tax, in interest expense, or $0.02 per diluted share, at an effective rate of 7.93%, of which $1.6 million related to the coupon rate of 3.375% and $1.7

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million related to discount amortization. During the three months ended June 30, 2009, the Company recognized $2.2 million, $1.5 million, net of tax, in interest expense, or $0.02 per diluted share, at an effective rate of 7.93%, of which $1.1 million related to the coupon rate of 3.375% and $1.1 million related to discount amortization. During the six months ended June 30, 2009, the Company recognized $4.9 million, $3.2 million, net of tax, in interest expense, or $0.04 per diluted share, at an effective rate of 7.93%, of which $2.5 million related to the coupon rate of 3.375% and $2.4 million related to discount amortization.

The notes will be convertible under certain circumstances into shares of the Company s common stock (Common Stock) at an initial conversion rate of 19.9695 shares of Common Stock per $1,000 principal amount of notes, which is equal to an initial conversion price of approximately $50.08 per share. Upon conversion of a note, a holder will receive, at the Company s election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At June 30, 2010, the number of conversion shares potentially issuable in relation to the 3.375% Convertible Senior Notes was 1.9 million.

The indenture governing the 3.375% Convertible Senior Notes contains a provision under which an event of default by the Company or by any subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default: a) is caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

The Company determined that upon maturity or redemption it has the intent and ability to settle the principal amount of its 3.375% Convertible Senior Notes in cash, and any additional conversion consideration spread (the excess of conversion value over face value) in shares of the Company s Common Stock. There were no stock equivalents to exclude from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the three and six months ended June 30, 2010 and 2009 related to the assumed conversion of the 3.375% Convertible Senior Notes under the if-converted method as there was no excess of conversion value over face value in any of these periods. In April 2009, the Company repurchased $20.0 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $6.1 million, resulting in a gain of $10.7 million. In addition, the Company expensed $0.4 million of unamortized issuance costs in connection with the retirement. In June 2009, the Company retired $45.8 million aggregate principal amount of its 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share and payment of accrued interest, resulting in a gain of $4.4 million. In addition, the Company expensed $1.0 million of unamortized issuance costs in connection with the retirement. In accordance with Financial Accounting Standards Board s (FASB) Accounting Standards Codification (ASC) Topic 470-20, *Debt Debt with Conversion and Other Options*, the settlement consideration was allocated to the extinguishment of the liability component in an amount equal to the fair value of that component immediately prior to extinguishment, with the difference between this allocation and the net carrying amount of the liability component and unamortized debt issuance costs recognized as a gain or loss on debt extinguishment. If there would have been any remaining settlement consideration, it would have been allocated to the reacquisition of the equity component and recognized as a reduction of Stockholders Equity.

Other debt

In connection with the TODCO acquisition in July 2007, one of our domestic subsidiaries assumed approximately $3.5 million of 7.375% Senior Notes due in April 2018. There are no financial or operating covenants associated with these notes.

Fair value estimate

The fair value of the Company s 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of the Company s 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. The following table provides the carrying value and fair value of our long-term debt instruments:

	June 30, 2010	December 31, 2009

	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility, due July 2013	$478.8	$421.4	$482.9	$468.4
10.5% Senior Secured Notes, due October 2017	292.6	265.9	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	84.7	70.0	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.4	3.5	3.0

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5. Derivative Instruments and Hedging

The Company is required to recognize all of its derivative instruments as either assets or liabilities in the statement of financial position at fair value. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, a company must designate the hedging instrument, based upon the exposure being hedged, as a fair value hedge, cash flow hedge, or a hedge of a net investment in a foreign operation.

The Company periodically uses derivative instruments to manage its exposure to interest rate risk, including interest rate swap agreements to effectively fix the interest rate on variable rate debt and interest rate collars to limit the interest rate range on variable rate debt. These hedge transactions have historically been accounted for as cash flow hedges.

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the period or periods during which the hedged transaction affects earnings. The effective portion of the interest rate swaps and collars hedging the exposure to variability in expected future cash flows due to changes in interest rates is reclassified into interest expense. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, or hedged components excluded from the assessment of effectiveness, is recognized in interest expense.

In May 2008 and July 2007, the Company entered into derivative instruments with the purpose of hedging future interest payments on its term loan facility. In May 2008, the Company entered into a floating to fixed interest rate swap with varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million which was settled on December 31, 2009. The Company received an interest rate of three-month LIBOR and paid a fixed coupon of 2.980% over six quarters. The terms and settlement dates of the swap matched those of the term loan through July 27, 2009, the date of the Credit Amendment. In July 2007, the Company entered into a floating to fixed interest rate swap with decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million which was settled on April 1, 2009. The Company received a payment equal to the product of three-month LIBOR and the notional amount and paid a fixed coupon of 5.307% on the notional amount over six quarters. The terms and settlement dates of the swap matched those of the term loan. In July 2007, the Company also entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010 with a ceiling of 5.75% and a floor of 4.99%. The counterparty is obligated to pay the Company in any quarter that actual LIBOR resets above 5.75% and the Company pays the counterparty in any quarter that actual LIBOR resets below 4.99%. The terms and settlement dates of the collar matched those of the term loan through July 27, 2009, the date of the Credit Amendment.

As a result of the inclusion of a LIBOR floor in the Credit Agreement, the Company does not believe, as of July 27, 2009 and on an ongoing basis, that the interest rate swap and collar will be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, the Company has prospectively discontinued cash flow hedge accounting for the interest rate swap and collar as of July 27, 2009 and no longer applies cash flow hedge accounting to these instruments. Because cash flow hedge accounting will not be applied to these instruments, changes in fair value related to the interest rate swap and collar subsequent to July 27, 2009 have been recorded in earnings and will be on a go-forward basis. As a result of discontinuing the cash flow hedging relationship, the Company recognized an increase in fair value of $0.1 million and a decrease in fair value of $0.3 million related to the hedge ineffectiveness of its collar as Interest Expense in its Consolidated Statements of Operations for the three and six months ended June 30, 2010, respectively. The Company did not recognize a gain or loss due to hedge ineffectiveness in its Consolidated Statements of Operations for the three and six months ended June 30, 2009 related to interest rate derivative instruments. The

Company expects to realize all of the unrealized loss in the Consolidated Statements of Operations during 2010.

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The following table provides the fair values of the Company s interest rate derivatives (in thousands):

	June 30, 2010 Balance Sheet Classification	Fair Value	December 31, 2009 Balance Sheet Classification	Fair Value
Derivatives(a):				
Interest rate contracts:				
	Other	$	Other	$
	Total Asset Derivatives	$	Total Asset Derivatives	$
	Other Current Liabilities	$ 6,976	Other Current Liabilities	$ 10,312
	Other Liabilities		Other Liabilities	
	Total Liability Derivatives	$ 6,976	Total Liability Derivatives	$ 10,312

(a) These interest rate contracts were designated as cash flow hedges through July 27, 2009.

The following table provides the effect of the Company s interest rate derivatives on the Consolidated Statements of Operations (in thousands):

	Three Months Ended June 30,							
	2010	2009		2010	2009		2010	2009
Derivatives(a)	**I.**		**II.**	**III.**		**IV.**	**V.**	
Interest rate contracts	$	$ (605)	Interest Expense	$ (2,972)	$ (3,989)	Interest Expense	$ 104	$

	Six Months Ended June 30,							
	2010	2009		2010	2009		2010	2009
Derivatives(a)	**I.**		**II.**	**III.**		**IV.**	**V.**	
Interest rate contracts	$	$ (3,880)	Interest Expense	$ (6,170)	$ (8,403)	Interest Expense	$ (259)	$

(a) These interest rate contracts were designated as cash flow hedges through July 27, 2009.

I. Amount of Gain (Loss), Net of Taxes Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)

II. Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)

III. Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)

IV. Classification of Gain (Loss) Recognized in Income (Loss) on Derivative

V. Amount of Gain (Loss) Recognized in Income (Loss) on Derivative

A summary of the changes in Accumulated Other Comprehensive Loss (in thousands):

Cumulative unrealized loss, net of tax of $3,108, as of December 31, 2009	$ (5,773)
Reclassification of losses into net income, net of tax of $2,159	4,011

Cumulative unrealized loss, net of tax of $949, as of June 30, 2010	$ (1,762)

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6. Fair Value Measurements

FASB ASC Topic 820-10, *Fair Value Measurements and Disclosures* defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurements; however, it does not require any new fair value measurements, rather, its application is made pursuant to other accounting pronouncements that require or permit fair value measurements.

Fair value measurements are generally based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our view of market assumptions in the absence of observable market information. The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. FASB ASC Topic 820-10, *Fair Value Measurements and Disclosures* includes a fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The fair value hierarchy consists of the following three levels:

Level 1 - Inputs are quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs are quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable and market-corroborated inputs which are derived principally from or corroborated by observable market data.

Level 3 - Inputs are derived from valuation techniques in which one or more significant inputs or value drivers are unobservable.

The valuation techniques that may be used to measure fair value are as follows:

(A) Market approach Uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities

(B) Income approach Uses valuation techniques to convert future amounts to a single present amount based on current market expectations about those future amounts, including present value techniques, option-pricing models and excess earnings method

(C) Cost approach Based on the amount that currently would be required to replace the service capacity of an asset (replacement cost)

As of January 1, 2010, the Company adopted the FASB Accounting Standards Update (ASU) No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06) which requires additional disclosures about the various classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the activity in Level 3 fair value measurements and the transfers between Levels 1, 2, & 3. The requirement for disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements are effective for interim and annual reporting periods beginning after December 15, 2010 and will be adopted by the Company on January 1, 2011 (See Note 12).

As of June 30, 2010 the fair value of the Company s interest rate derivative was in a liability position in the amount of $7.0 million. The fair value of the interest rate derivative was determined based on a discounted cash flow approach using market observable inputs including forward interest rates and credit spreads.

The following table represents our derivative liabilities measured at fair value on a recurring basis as of June 30, 2010 (in thousands):

Quoted
Prices in

	Total Fair Value Measurement June 30, 2010	Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
Interest Rate Contracts	$ 6,976	$	$ 6,976	$	A

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The following table represents our derivative liabilities measured at fair value on a recurring basis as of December 31, 2009 (in thousands):

	Total Fair Value Measurement December 31, 2009	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
Interest Rate Contracts	$ 10,312	$	$ 10,312	$	A

The following table represents our assets measured at fair value on a non-recurring basis for which an impairment measurement was made as of December 31, 2009 (in thousands):

	Total Fair Value Measurement December 31, 2009	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique	Total Gain (Loss)
Assets Held for Sale	$	$	$	$	A	$(26,882)

The Company realized approximately $26.9 million ($13.1 million, net of tax) of impairment charges related to the write-down of *Hercules 110* to fair value less costs to sell during the second quarter of 2009 (See Note 3). The sale of *Hercules 110* was completed in August 2009 (See Note 3).

7. Stock-based Compensation

The Company s 2004 Long-Term Incentive Plan (the 2004 Plan) provides for the granting of stock options, restricted stock, performance stock awards and other stock-based awards to selected employees and non-employee directors of the Company. At June 30, 2010, approximately 2.3 million shares were available for grant or award under the 2004 Plan.

During the six months ended June 30, 2010, the Company granted 1,355,000 stock options with a weighted average exercise price of $3.77 and 782,532 restricted stock awards with a weighted average grant-date fair value per share of $3.79. The Company recognized $1.7 million and $1.8 million in stock-based compensation expense during the three and six months ended June 30, 2010, respectively, which includes a reduction of $0.3 million and $2.1 million due to a change in the Company s estimated forfeiture rate, respectively. The Company recognized $2.1 million and $4.1 million in stock-based compensation expense during the three and six months ended June 30, 2009, respectively.

The unrecognized compensation cost related to the Company s unvested stock options and restricted stock grants as of June 30, 2010 was $4.0 million and $4.3 million, respectively, and is expected to be recognized over a weighted-average period of 1.8 years and 1.7 years, respectively.

8. Supplemental Cash Flow Information

The Company had non-cash financing activities related to its June 2009 retirement of $45.8 million aggregate principal amount of its 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share ($34.0 million) and payment of accrued interest, resulting in a gain of $4.4 million (See Note 4).

	Six Months Ended June 30,	
	2010	**2009**
	(In thousands)	
Cash paid during the period for:		
Interest, net of capitalized interest	$28,628	$14,982
Income taxes	23,603	12,038

During the six months ended June 30, 2009, the Company capitalized interest of $0.3 million. There was no interest capitalized during the six months ended June 30, 2010.

9. Income Tax

In connection with the July 2007 acquisition of TODCO, the Company, as successor to TODCO, and TODCO s former parent, Transocean Ltd., are parties to a tax sharing agreement that was originally entered into in connection with TODCO s initial public offering in 2004. The tax sharing agreement was amended and restated in November 2006 in a negotiated settlement of disputes between Transocean and TODCO over the terms of the original tax sharing agreement. The tax sharing agreement continues to require that additional payments be made to Transocean based on a portion of the expected tax benefit from the exercise of certain compensatory stock options to acquire Transocean common stock attributable to current and former TODCO employees and board members. The estimated amount of payments to Transocean related to compensatory options that remain outstanding at June 30, 2010, assuming a Transocean stock price of $46.33 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at June 30, 2010), is approximately $0.1 million. The Company accounts for the exercise of Transocean

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stock options held by current and former TODCO employees and board members in the period in which such option is exercised. As tax deductions are generated from the exercise of the stock options the Company takes a current tax deduction for the value of the stock option tax deduction, pays Transocean for 55% of the tax benefit and increases additional paid-in capital by 45% of the tax benefit. Because of the Company s current NOL position, the tax benefit of the stock option deduction is reclassified as a reduction in net deferred tax liability. There is no certainty that the Company will realize future economic benefits from TODCO s tax benefits equal to the amount of the payments required under the tax sharing agreement.

The Company s tax filings for various periods are subject to audit by the tax authorities in most jurisdictions where we conduct business. Internationally, an income tax return for 2004 is currently under examination. The timing and effect on the Company s consolidated financial statements of the resolution of this income tax examination is highly uncertain due to various underlying factors. These factors include, among other things, the amount and nature of additional taxes potentially asserted by local tax authorities; the willingness of local tax authorities to negotiate a reasonable and appropriate settlement through an administrative process; and the impartiality of the local courts. The amounts ultimately paid, if any, upon the resolution of the issues raised by the tax authorities in any audit may differ materially from the amounts accrued for each year. While it is possible that some of these examinations may be resolved in the next 12 months, the Company cannot predict or provide assurance as to the ultimate outcome of existing or future tax assessments.

In December 2002, TODCO received an assessment from SENIAT, the national Venezuelan tax authority, for approximately $20.7 million (based on the current exchange rates at the time of the assessment and inclusive of penalties) relating to calendar years 1998 through 2001. In March 2003, TODCO paid approximately $2.6 million of the assessment, plus approximately $0.3 million in interest, and we are contesting the remainder of the assessment with the Venezuelan Tax Court. After TODCO made the partial assessment payment, it received a revised assessment in September 2003 of approximately $16.7 million (based on the current exchange rates at the time of the assessment and inclusive of penalties). Thereafter, TODCO filed an administrative tax appeal with SENIAT and the tax authority rendered a decision that reduced the tax assessment to $8.1 million (based on the current exchange rates at the time of the decision). TODCO then initiated a judicial tax court appeal with the Venezuelan Tax Court to set aside the $8.1 million administrative tax assessment. In August 2008, the Venezuelan Tax Court ruled in favor of TODCO; however, SENIAT has the right to appeal this case to the Venezuelan Supreme Court. In July 2009, the Company settled the taxes and interest portion of the assessment for approximately 3.3 million Bolivares Fuertes, or approximately $1.5 million (based on the official exchange rate at the date of settlement). The Company is disputing any residual penalties which are currently assessed at 3.4 million Bolivares Fuertes, or $0.8 million (based on the official exchange rate at June 30, 2010). The Company, as successor to TODCO, is fully indemnified by TODCO s former parent, Transocean Ltd. related to this settlement. The Company does not expect the ultimate resolution of this tax assessment and settlement to have a material impact on its consolidated results of operations, financial condition or cash flows. In January 2008, SENIAT commenced an audit for the 2003 calendar year, which was completed in the fourth quarter of 2008. The Company has not yet received any proposed adjustments from SENIAT for that year.

In March 2007, a subsidiary of the Company received an assessment from the Mexican tax authorities related to its operations for the 2004 tax year. This assessment contests the Company s right to certain deductions and also claims it did not remit withholding tax due on certain of these deductions. In accordance with local statutory requirements, we provided a surety bond for an amount equal to $13.2 million as of June 30, 2010, which was released in July 2010, to contest these assessments (See Notes 11 and 13). In 2008, the Mexican tax authorities commenced an audit for the 2005 tax year. During the quarter ended March 31, 2010, the Company effectively reached a compromise settlement of all issues for 2004 2007 in the amount of approximately $10.8 million, of which $5.7 million relating to 2004-2005 was paid as of June 30, 2010. The amount attributed to 2006-2007 is expected to be paid in the third quarter of 2010. This resulted in the Company reversing previously provided reserves and an associated tax benefit in the year in the amount of approximately $6.0 million. The criteria for effective settlement of this reserve is that the tax authority has completed all its examination procedures, the Company does not intend to appeal and the possibility is remote that the tax authority would reexamine any aspect of the tax position.

As of June 30, 2010, the Company had Taxes Receivable of $16.9 million which is included in Other on the Consolidated Balance Sheets.

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10. Segments

The Company reports its business activities in six business segments: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats, (5) International Liftboats and (6) Delta Towing. The financial information of the Company s discontinued operation is not included in the financial information presented for the Company s reporting segments. The Company eliminates inter-segment revenue and expenses, if any.

The following describes the Company s reporting segments as of June 30, 2010:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Twelve of the jackup rigs are either working on short-term contracts or available for contracts and ten are cold-stacked. All three submersibles are cold-stacked.

International Offshore includes eight jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. The Company has two jackup rigs working offshore in each of India and Saudi Arabia. The Company has one jackup rig contracted offshore in Malaysia and one platform rig under contract in Mexico. In addition, the Company has one jackup rig warm-stacked in each of Bahrain and Gabon and one jackup rig contracted to a customer in Angola, however, the rig is currently on stand-by in Gabon.

Inland includes a fleet of 6 conventional and 11 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of the inland barges are either operating on short-term contracts or available and 14 are cold-stacked.

Domestic Liftboats includes 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating or available and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-one are operating or available offshore West Africa, including five liftboats owned by a third party, one is cold-stacked offshore West Africa and two are operating or available in the Middle East region.

Delta Towing the Company s Delta Towing business operates a fleet of 29 inland tugs, 12 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and from time to time along the Southeastern coast and in Mexico. Of these vessels, 21 crew boats, 12 inland tugs, five offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working, being repaired or available for contracts.

The Company s jackup rigs, submersible rigs and platform rigs are used primarily for exploration and development drilling in shallow waters. The Company s liftboats are self-propelled, self-elevating vessels that support a broad range of offshore maintenance and construction services throughout the life of an oil or natural gas well.

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Information regarding reportable segments is as follows (in thousands):

	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
	Revenue	Income (Loss) from Operations	Depreciation & Amortization	Revenue	Income (Loss) from Operations	Depreciation & Amortization
Domestic Offshore	$ 34,143	$ (20,520)	$ 17,170	$ 63,105	$ (50,646)	$ 33,709
International Offshore	73,493	24,237	14,473	146,935	46,723	29,404
Inland	5,180	(7,728)	6,239	9,931	(13,035)	13,745
Domestic Liftboats	17,895	2,993	3,668	29,338	427	7,868
International Liftboats	27,187	6,493	4,368	53,149	11,796	9,059
Delta Towing	7,997	(282)	1,614	14,286	(1,223)	3,204
	165,895	5,193	47,532	316,744	(5,958)	96,989
Corporate		(10,767)	818		(19,960)	1,615
Total Company	$ 165,895	$ (5,574)	$ 48,350	$ 316,744	$ (25,918)	$ 98,604

	Three Months Ended June 30, 2009			Six Months Ended June 30, 2009		
	Revenue	Income (Loss) from Operations	Depreciation & Amortization	Revenue	Income (Loss) from Operations	Depreciation & Amortization
Domestic Offshore	$ 36,970	$ (20,180)	$ 15,092	$ 96,151	$ (32,120)	$ 30,132
International Offshore (a)	101,757	17,175	16,749	205,209	60,060	31,933
Inland	96	(17,372)	8,283	13,009	(33,616)	16,276
Domestic Liftboats	18,884	212	5,747	41,494	3,231	10,796
International Liftboats	20,747	8,378	2,278	39,389	15,238	4,662
Delta Towing	5,237	(3,065)	2,142	11,930	(7,322)	4,426
	183,691	(14,852)	50,291	407,182	5,471	98,225
Corporate		(10,977)	800		(22,191)	1,712
Total Company	$ 183,691	$ (25,829)	$ 51,091	$ 407,182	$ (16,720)	$ 99,937

(a) Income (Loss) from Operations for the Company s International Offshore Segment includes a $26.9 million impairment of property and equipment charge for the three and six months ended June 30, 2009.

	Total Assets	
	June 30, 2010	**December 31, 2009**
Domestic Offshore	$ 865,890	$ 870,723
International Offshore	785,104	860,252
Inland	151,211	160,354
Domestic Liftboats	89,377	88,942
International Liftboats	167,141	164,221
Delta Towing	60,313	62,563
Corporate	74,188	70,421
Total Company	$ 2,193,224	$ 2,277,476

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

11. Commitments and Contingencies

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of June 30, 2010, management did not believe any accruals were necessary in accordance with FASB Codification Topic 450-20, *Contingencies Loss Contingencies.*

In connection with the July 2007 acquisition of TODCO, the Company assumed certain material legal proceedings from TODCO and its subsidiaries.

In October 2001, TODCO was notified by the U.S. Environmental Protection Agency (EPA) that the EPA had identified a subsidiary of TODCO as a potentially responsible party under CERCLA in connection with the Palmer Barge Line superfund site located in Port Arthur, Jefferson County, Texas. Based upon the information provided by the EPA and the Company s review of its internal records to date, the Company disputes the Company s designation as a potentially responsible party and does not expect that the ultimate outcome of this case will have a material adverse effect on our consolidated results of operations, financial position or cash flows. The Company continues to monitor this matter.

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases that have been filed in the Circuit Courts of the State of Mississippi involving 768 persons that allege personal injury or whose heirs claim their deaths arose out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints name as defendants, among others, certain of TODCO s subsidiaries and certain subsidiaries of TODCO s former parent to whom TODCO may owe indemnity, and other unaffiliated defendant companies, including companies that allegedly manufactured drilling-related products containing asbestos that are the subject of the complaints. The number of unaffiliated defendant companies involved in each complaint ranges from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things, negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. All of these cases were assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made would be properly served against specific defendants. Approximately 700 questionnaires were returned and the remaining plaintiffs, who did not submit a questionnaire reply, have had their suits dismissed without prejudice. Of the respondents, approximately 100 shared periods of employment by TODCO and its former parent which could lead to claims against either company, even though many of these plaintiffs did not state in their questionnaire answers that the employment actually involved exposure to asbestos. After providing the questionnaire, each plaintiff was further required to file a separate and individual amended complaint naming only those defendants against whom they had a direct claim as identified in the questionnaire answers. Defendants not identified in the amended complaints were dismissed from the plaintiffs litigation. To date, three plaintiffs named TODCO as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named TODCO as a defendant may attempt to add TODCO as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. The Company has not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. More than three years has passed since the court ordered that amended complaints be filed by each individual plaintiff, and the original complaints. No additional plaintiffs have attempted to name TODCO as a defendant and such actions may now be time-barred. The Company intends to defend vigorously and does not expect the ultimate outcome of these lawsuits to have a material adverse effect on its consolidated results of operations, financial position or cash flows.

The Company and its subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of business. The Company does not believe that ultimate liability, if any, resulting from any such other pending litigation will have a material adverse effect on its business or consolidated financial statements.

The Company cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any other pending litigation. There can be no assurance that the Company s belief or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct, and the eventual outcome of these matters could materially differ from management s current estimates.

Insurance

The Company maintains insurance coverage that includes coverage for physical damage, third party liability, workers compensation and employers liability, general liability, vessel pollution and other coverages.

In April 2010, the Company completed the annual renewal of all of its key insurance policies. The Company s primary marine package provides for hull and machinery coverage for the Company s rigs and liftboats up to a scheduled value of each asset. The

HERCULES OFFSHORE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
UNAUDITED

total maximum amount of coverage for these assets is $2.1 billion. The marine package includes protection and indemnity and maritime employers liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employers liability coverage) of $5.0 million per occurrence with excess liability coverage up to $200.0 million. The marine package also provides coverage for cargo and charter s legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of $100.0 million for property damage and removal of debris liability coverage. The Company also procured an additional $75.0 million excess policy for removal of debris and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of $1.0 million, and $1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is $25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy with a $3.0 million deductible providing limits as required by applicable law, including the Oil Pollution Act of 1990. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, the Company has separate policies providing coverage for onshore foreign and domestic general liability, employer s liability, auto liability and non-owned aircraft liability, with customer deductibles and coverage as well as a separate primary marine package for its Delta Towing business.

In 2010, in connection with the renewal of certain of its insurance policies, the Company entered into an agreement to finance a portion of its annual insurance premiums. Approximately $24.1 million was financed through this arrangement, and $21.7 million was outstanding at June 30, 2010. The interest rate on the note was 3.79% and it is scheduled to mature in March 2011. Additionally, there was $0.2 million outstanding on the $1.9 million note related to the 2009 insurance renewals for the Company s Delta Towing business. The interest rate on this note is 3.75% and it is scheduled to mature in July 2010.

The Company is self-insured for the deductible portion of its insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of the Company s insurance coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. However, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences.

Surety Bonds, Bank Guarantees and Unsecured Letters of Credit

The Company has $50.6 million outstanding related to surety bonds at June 30, 2010. The surety bonds guarantee our performance as it relates to the Company s drilling contracts, tax and other obligations in various jurisdictions. These obligations could be called at any time prior to the expiration dates. The obligations that are the subject of the surety bonds are geographically concentrated primarily in Mexico and the U.S. In July 2010, a $13.2 million surety bond related to the Mexico tax assessment was released (See Notes 9 and 13).

The Company had a $1.0 million unsecured bank guarantee and a $0.1 million unsecured letter of credit outstanding at June 30, 2010.

12. Accounting Pronouncements

In January 2010, the FASB issued ASU 2010-06 which requires additional disclosures about the various classes of assets and liabilities measured at fair value, the valuation techniques and inputs used, the activity in Level 3 fair value measurements and the transfers between Levels 1, 2, & 3. The disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements, which are effective for interim and annual reporting periods beginning after December 15, 2010. The Company adopted the required portions of ASU 2010-06 as of January 1, 2010 with no material impact to its consolidated financial statements and will adopt the remaining portions on January 1, 2011 with no expected material impact on its consolidated financial statements (See Note 6).

13. Subsequent Events

In July 2010, the Company increased its restricted cash balance by $6.1 million as additional collateral to support surety bonds related to its Mexico and U.S. operations (See Note 1).

In July 2010, the Company entered into an agreement to sell retired jackup *Hercules 155* for $4.8 million (See Note 3).

In July 2010, a $13.2 million surety bond related to the Mexico tax assessment was released (See Notes 9 and 11).

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the accompanying unaudited consolidated financial statements as of June 30, 2010 and for the three and six months ended June 30, 2010 and June 30, 2009, included elsewhere herein, and with our Annual Report on Form 10-K for the year ended December 31, 2009. The following information contains forward-looking statements. Please read Forward-Looking Statements below for a discussion of certain limitations inherent in such statements. Please also read Risk Factors in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009, Item 1A of Part II of our quarterly report on Form 10-Q for the quarter ended March 31, 2010 and Item 1A of Part II of this quarterly report for a discussion of certain risks facing our company.

OVERVIEW

We are a leading provider of shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally. We provide these services to national oil and gas companies, major integrated energy companies and independent oil and natural gas operators. As of July 20, 2010, we owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels and 60 liftboat vessels. In addition, we operate five liftboat vessels owned by a third party. We own three retired jackup rigs and two retired inland barges, all located in the U.S. Gulf of Mexico, which are currently not expected to re-enter active service. Our diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection, maintenance and decommissioning operations in several key shallow water provinces around the world.

In January 2009, we reclassified four of our cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of our cold-stacked inland barges as retired; subsequently in each of September and November 2009, we sold one retired inland barge for approximately $0.2 million and $0.4 million, respectively. In December 2009 we entered into an agreement to sell our retired jackups *Hercules 191* and *Hercules 255* for $5.0 million each. The sale of the *Hercules 191* was completed in April 2010 for gross proceeds of $5.0 million and the sale of the *Hercules 255* is expected to close in the third quarter of 2010. In February 2010, we entered into an agreement to sell six of our retired barges for $3.0 million. The sale of three of the six retired barges was completed in the quarter ended March 31, 2010 for gross proceeds of $2.2 million. The sale of the remaining three barges was completed in April 2010 for gross proceeds of $0.8 million. Additionally, in July 2010, we entered into an agreement to sell retired jackup *Hercules 155* for $4.8 million.

We report our business activities in six business segments, which, as of July 20, 2010, included the following:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eleven of the jackup rigs are either working on short-term contracts or available for contracts and eleven are cold-stacked. All three submersibles are cold-stacked.

International Offshore includes eight jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have two jackup rigs working offshore in each of India and Saudi Arabia. We have one jackup rig contracted offshore in Malaysia and one platform rig under contract in Mexico. In addition, we have one jackup rig warm-stacked in each of Bahrain and Gabon and one jackup rig contracted to a customer in Angola, however, the rig is currently on stand-by in Gabon.

Inland includes a fleet of 6 conventional and 11 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of our inland barges are either operating on short-term contracts or available and 14 are cold-stacked.

Domestic Liftboats includes 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating or available and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-one are operating or available offshore West Africa, including five liftboats owned by a third party, one is cold-stacked offshore West Africa and two are operating or available in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 29 inland tugs, 12 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and from time to time along the Southeastern coast and in Mexico. Of these vessels, 18 crew boats, 11 inland tugs, five offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working, being repaired or available for contracts.

In December 2009, we entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby we would market, manage and operate two Friede & Goldman Super M2 design, new-build jackup drilling rigs each with a maximum water depth of 300 feet. The rigs are currently under construction and one is scheduled to be delivered in each of the fourth quarter of 2010 and the first quarter of 2011. We are actively marketing the rigs globally on an exclusive basis.

In January 2010, we entered into an agreement with SKDP 1 Ltd., an affiliate of Skeie Drilling & Production ASA, to market, manage and operate an ultra high specification KFELS Class N new-build jackup drilling rig with a maximum water depth of 400 feet. The agreement was limited to a specified opportunity in the Middle East and expired by its terms during the second quarter when the rig was not selected by the operator.

Our jackup and submersible rigs and our barge rigs are used primarily for exploration and development drilling in shallow waters. Under most of our contracts, we are paid a fixed daily rental rate called a dayrate, and we are required to pay all costs associated with our own crews as well as the upkeep and insurance of the rig and equipment.

Our liftboats are self-propelled, self-elevating vessels that support a broad range of offshore support services, including platform maintenance, platform construction, well intervention and decommissioning services throughout the life of an oil or natural gas well. Under most of our liftboat contracts, we are paid a fixed dayrate for the rental of the vessel, which typically includes the costs of a small crew of four to eight employees, and we also receive a variable rate for reimbursement of other operating costs such as catering, fuel, rental equipment and other items.

Our revenues are affected primarily by dayrates, fleet utilization, the number and type of units in our fleet and mobilization fees received from our customers. Utilization and dayrates, in turn, are influenced principally by the demand for rig and liftboat services from the exploration and production sectors of the oil and natural gas industry. Our contracts in the U.S. Gulf of Mexico tend to be short-term in nature and are heavily influenced by changes in the supply of units relative to the fluctuating expenditures for both drilling and production activity. Our international drilling contracts and some of our liftboat contracts in West Africa are longer-term in nature.

Our backlog at July 20, 2010 totaled approximately $316.3 million for our executed contracts, excluding the amount related to our Angola contract. Approximately $162.0 million of this backlog is expected to be realized during the remainder of 2010. We calculate our backlog, or future contracted revenue, as the contract dayrate multiplied by the number of days remaining on the contract, assuming full utilization. Backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. The amount of actual revenues earned and the actual periods during which revenues are earned will be different than the backlog disclosed or expected due to various factors. Downtime due to various operational factors, including unscheduled repairs, maintenance, weather and other factors (some of which are beyond our control), may result in lower dayrates than the full contractual operating dayrate. In some of the contracts, our customer has the right to terminate the contract without penalty and in certain instances, with little or no notice.

Our operating costs are primarily a function of fleet configuration and utilization levels. The most significant direct operating costs for our Domestic Offshore, International Offshore and Inland segments are wages paid to crews, maintenance and repairs to the rigs, and insurance. These costs do not vary significantly whether the rig is operating under contract or idle, unless we believe that the rig is unlikely to work for a prolonged period of time, in which case we may decide to cold-stack or warm-stack the rig. Cold-stacking is a common term used to describe a rig that is expected to be idle for a protracted period and typically for which routine maintenance is suspended and the crews are either redeployed or laid-off. When a rig is cold-stacked, operating expenses for the rig are significantly reduced because the crew is smaller and maintenance activities are suspended. Placing rigs in service that have been cold-stacked typically requires a lengthy reactivation project that can involve significant expenditures and potentially additional regulatory review, particularly if the rig has been cold-stacked for a long period of time. Warm-stacking is a term used for a rig expected to be idle for a period of time that is not as prolonged as is the case with a cold-stacked rig. Maintenance is continued for warm-stacked rigs. Crews are reduced but a small crew is retained. Warm-stacked rigs generally can be reactivated in three to four weeks.

The most significant costs for our Domestic Liftboats and International Liftboats segments are the wages paid to crews and the amortization of regulatory drydocking costs. Unlike our Domestic Offshore, International Offshore and Inland segments, a significant portion of the expenses incurred with operating each liftboat are paid for or reimbursed by the customer under contractual terms and prices. This includes catering, fuel, oil, rental equipment, crane overtime and other items. We record reimbursements from customers as revenues and the related expenses as operating costs. Our liftboats are required to undergo regulatory inspections every year and to be drydocked two times every five years; the drydocking expenses and length of time in drydock vary depending on the condition of the vessel. All costs associated with regulatory inspections, including related drydocking costs, are deferred and amortized over a period of twelve months.

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RESULTS OF OPERATIONS

The following table sets forth financial information by operating segment and other selected information for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Dollars in thousands)			
Domestic Offshore:				
Number of rigs (as of end of period)	25	23	25	23
Revenues	$ 34,143	$ 36,970	$ 63,105	$ 96,151
Operating expenses	37,229	40,746	76,381	95,159
Depreciation and amortization expense	17,170	15,092	33,709	30,132
General and administrative expenses	264	1,312	3,661	2,980
Operating loss	$ (20,520)	$ (20,180)	$ (50,646)	$ (32,120)
International Offshore:				
Number of rigs (as of end of period)	9	12	9	12
Revenues	$ 73,493	$ 101,757	$ 146,935	$ 205,209
Operating expenses	32,610	39,128	67,329	83,269
Impairment of property and equipment		26,882		26,882
Depreciation and amortization expense	14,473	16,749	29,404	31,933
General and administrative expenses	2,173	1,823	3,479	3,065
Operating income	$ 24,237	$ 17,175	$ 46,723	$ 60,060
Inland:				
Number of barges (as of end of period)	17	17	17	17
Revenues	$ 5,180	$ 96	$ 9,931	$ 13,009
Operating expenses	6,363	8,857	12,080	29,121
Depreciation and amortization expense	6,239	8,283	13,745	16,276
General and administrative expenses	306	328	(2,859)	1,228
Operating loss	$ (7,728)	$ (17,372)	$ (13,035)	$ (33,616)
Domestic Liftboats:				
Number of liftboats (as of end of period)	41	45	41	45
Revenues	$ 17,895	$ 18,884	$ 29,338	$ 41,494
Operating expenses	10,853	12,418	20,167	26,552
Depreciation and amortization expense	3,668	5,747	7,868	10,796
General and administrative expenses	381	507	876	915
Operating income	$ 2,993	$ 212	$ 427	$ 3,231
International Liftboats:				
Number of liftboats (as of end of period)	24	20	24	20
Revenues	$ 27,187	$ 20,747	$ 53,149	$ 39,389
Operating expenses	14,897	9,113	29,359	17,220

Depreciation and amortization expense	4,368	2,278	9,059	4,662
General and administrative expenses	1,429	978	2,935	2,269
Operating income	$ 6,493	$ 8,378	$ 11,796	$ 15,238

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	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(Dollars in thousands)			
Delta Towing:				
Revenues	$ 7,997	$ 5,237	$ 14,286	$ 11,930
Operating expenses	6,369	5,835	11,641	14,020
Depreciation and amortization expense	1,614	2,142	3,204	4,426
General and administrative expenses	296	325	664	806
Operating loss	$ (282)	$ (3,065)	$ (1,223)	$ (7,322)
Total Company:				
Revenues	$ 165,895	$ 183,691	$ 316,744	$ 407,182
Operating expenses	108,321	116,097	216,957	265,341
Impairment of property and equipment		26,882		26,882
Depreciation and amortization	48,350	51,091	98,604	99,937
General and administrative	14,798	15,450	27,101	31,742
Operating loss	(5,574)	(25,829)	(25,918)	(16,720)
Interest expense	(21,259)	(14,561)	(42,998)	(30,350)
Gain on early retirement of debt, net		13,747		13,747
Other, net	3,183	3,346	3,169	2,690
Loss before income taxes	(23,650)	(23,297)	(65,747)	(30,633)
Income tax benefit	4,666	11,510	30,807	14,335
Loss from continuing operations	(18,984)	(11,787)	(34,940)	(16,298)
Loss from discontinued operation, net of taxes		(242)		(675)
Net loss	$ (18,984)	$ (12,029)	$ (34,940)	$ (16,973)

The following table sets forth selected operational data by operating segment for the period indicated:

Three Months Ended June 30, 2010

	Operating Days	Available Days	Utilization (1)	Average Revenue per Day (2)	Average Operating Expense per Day (3)
Domestic Offshore	966	1,072	90.1%	$ 35,345	$ 34,729
International Offshore	533	819	65.1%	137,886	39,817
Inland	250	273	91.6%	20,720	23,308
Domestic Liftboats	2,503	3,458	72.4%	7,149	3,139
International Liftboats	1,224	2,154	56.8%	22,212	6,916

Three Months Ended June 30, 2009

Average

	Operating Days	Available Days	Utilization (1)	Average Revenue per Day (2)	Operating Expense per Day (3)
Domestic Offshore	706	1,136	62.1%	$ 52,365	$ 35,868
International Offshore	788	910	86.6%	129,133	42,998
Inland		303	0.0%	n/a	29,231
Domestic Liftboats	2,444	3,842	63.6%	7,727	3,232
International Liftboats	1,005	1,729	58.1%	20,644	5,271

	Six Months Ended June 30, 2010				
	Operating Days	Available Days	Utilization (1)	Average Revenue per Day (2)	Average Operating Expense per Day (3)
Domestic Offshore	1,789	2,062	86.8%	$ 35,274	$ 37,042
International Offshore	1,060	1,688	62.8%	138,618	39,887
Inland	490	543	90.2%	20,267	22,247
Domestic Liftboats	4,230	6,878	61.5%	6,936	2,932
International Liftboats	2,398	4,314	55.6%	22,164	6,806

	Six Months Ended June 30, 2009				
	Operating Days	Available Days	Utilization (1)	Average Revenue per Day (2)	Average Operating Expense per Day (3)
Domestic Offshore	1,570	2,520	62.3%	$ 61,243	$ 37,762
International Offshore	1,583	1,757	90.1%	129,633	47,393
Inland	298	1,026	29.0%	43,654	28,383
Domestic Liftboats	4,883	7,712	63.3%	8,498	3,443
International Liftboats	1,923	3,439	55.9%	20,483	5,007

(1) Utilization is defined as the total number of days our rigs or liftboats, as applicable, were under contract, known as operating days, in the period as a percentage of the total number of available days in the period. Days during which our rigs and liftboats were undergoing major refurbishments, upgrades or construction, and days during which our rigs and liftboats are cold-stacked, are not counted as available days. Days during which our liftboats are in the shipyard undergoing drydocking or inspection are considered available days for the purposes of calculating utilization.

(2) Average revenue per rig or liftboat per day is defined as revenue earned by our rigs or liftboats, as applicable, in the period divided by the total number of operating days for our rigs or liftboats, as applicable, in the period. Included in International Offshore revenue is a total of $3.7 million and $7.3 million related to amortization of deferred mobilization revenue for the three and six months ended June 30, 2010, respectively and $4.2 million and $8.0 million for the three and six months ended June 30, 2009, respectively. Included in International Liftboats revenue is a total of $0.5 million and $0.6 million related to amortization of deferred mobilization revenue for the three and six months ended June 30, 2010, respectively and $0.1 million for the six months ended June 30, 2009. There was no such revenue in the three months ended June 30, 2009.

(3) Average operating expense per rig or liftboat per day is defined as operating expenses, excluding depreciation and amortization, incurred by our rigs or liftboats, as applicable, in the period divided by the total number of available days in the period. We use available days to calculate average operating expense per rig or liftboat per day rather than operating days, which are used to calculate average revenue per rig or liftboat per day, because we incur operating expenses on our rigs and liftboats even when they are not under contract and earning a dayrate. In addition, the operating expenses we incur on our rigs and liftboats per day when they are not under contract are typically lower than the per day expenses we incur when they are under contract. Included in International Offshore operating expense is a total of $0.2 million and $0.4 million related to amortization of deferred mobilization expenses for the three and six months ended June 30, 2010, respectively

and $0.7 million and $1.4 million for the three and six months ended June 30, 2009, respectively. Included in International Liftboats operating expense is a total of $0.5 million and $1.2 million related to amortization of deferred mobilization expenses for the three and six months ended June 30, 2010, respectively. There was no such operating expense for the three and six months ended June 30, 2009.

For the Three Months Ended June 30, 2010 and 2009

Revenues

Consolidated. Total revenues for the three-month period ended June 30, 2010 (the Current Quarter) were $165.9 million compared with $183.7 million for the three-month period ended June 30, 2009 (the Comparable Quarter), a decrease of $17.8 million, or 10%. This decrease is further described below.

***Domestic Offshore*.** Revenues for our Domestic Offshore segment were $34.1 million for the Current Quarter compared with $37.0 million for the Comparable Quarter, a decrease of $2.8 million, or 8%. This decrease resulted primarily from a 33% decline in average dayrates which contributed an approximate $12 million decrease during the Current Quarter as compared to the Comparable Quarter. Partially offsetting this decrease is an increase in operating days to 966 days during the Current Quarter from 706 days during the Comparable Quarter, which contributed to an approximate $9 million increase in revenues.

***International Offshore*.** Revenues for our International Offshore segment were $73.5 million for the Current Quarter compared with $101.8 million for the Comparable Quarter, a decrease of $28.3 million, or 28%. Approximately $28 million of this decrease related to *Hercules 170* in warm stack during the Current Quarter and a decline in revenue associated with mobilizing *Hercules 205* and *Hercules 206* to the U.S. Gulf of Mexico. Average revenue per rig per day increased to $137,886 in the Current Quarter from $129,133 in the Comparable Quarter due primarily to contract mix as the warm-stacked *Hercules 170* and transferred rigs in the Current Quarter operated at lower average dayrates during the Comparable Quarter.

Inland. Revenues for our Inland segment were $5.2 million for the Current Quarter. There were essentially no revenues in the Comparable Quarter.

Domestic Liftboats. Revenues from our Domestic Liftboats segment were $17.9 million for the Current Quarter compared with $18.9 million in the Comparable Quarter, a decrease of $1.0 million, or 5%. This decrease resulted primarily from the decline in average revenue per vessel per day, $7,149 in the Current Quarter as compared to $7,727 per vessel per day in the Comparable Quarter, or a per vessel per day decrease of $578. The decrease in average revenue per vessel per day was due to weaker dayrates on our smaller class vessels and a shift in the average size of our available vessels due to the mobilization of four larger class vessels to West Africa in the fourth quarter of 2009. Operating days increased slightly in the Current Quarter to 2,503 as compared to 2,444 in the Comparable Quarter primarily due to activity associated with the Macondo blowout remediation efforts, partially offset by the transfer of four vessels to West Africa in the fourth quarter of 2009.

International Liftboats. Revenues for our International Liftboats segment were $27.2 million for the Current Quarter compared with $20.7 million in the Comparable Quarter, an increase of $6.4 million, or 31%. This increase resulted primarily from the transfer of four vessels to West Africa from the U.S. Gulf of Mexico which contributed approximately $9.6 million in revenue during the Current Quarter. Average revenue per liftboat per day increased to $22,212 in the Current Quarter compared with $20,644 in the Comparable Quarter while operating days increased to 1,224 days in the Current Quarter as compared to 1,005 days in the Comparable Quarter.

Delta Towing. Revenues for our Delta Towing segment were $8.0 million for the Current Quarter compared with $5.2 million in the Comparable Quarter, an increase of $2.8 million, or 53%. This increase resulted from an increase in operating days during the Current Quarter as compared to the Comparable Quarter due in part to activity associated with the Macondo blowout remediation efforts. The increase was partially offset by a decrease in average vessel dayrates during the Current Quarter as compared to the Comparable Quarter.

Operating Expenses

***Consolidated*.** Total operating expenses for the Current Quarter were $108.3 million compared with $116.1 million in the Comparable Quarter, a decrease of $7.8 million, or 7%. This decrease is further described below.

***Domestic Offshore*.** Operating expenses for our Domestic Offshore segment were $37.2 million in the Current Quarter compared with $40.7 million in the Comparable Quarter, a decrease of $3.5 million, or 9%. The decrease was driven by lower costs as a result of our cold stacking plan, a $3.1 million gain on the sale of *Hercules 191* in the Current Quarter, partially offset by increased utilization of our non-stacked jackup rigs and the transfer of *Hercules 205* to the U.S. GOM in the first quarter of 2010. Average operating expenses per rig per day were $34,729 in the Current Quarter compared with $35,868 in the Comparable Quarter.

International Offshore. Operating expenses for our International Offshore segment were $32.6 million in the Current Quarter compared with $39.1 million in the Comparable Quarter, a decrease of $6.5 million, or 17%. This decrease related primarily to *Hercules 170* in warm stack during the Current Quarter as well as *Hercules 205* and *Hercules 206* being transferred to Domestic Offshore in the first quarter of 2010 and the fourth quarter of 2009, respectively. These decreases were partially offset by increased cost for *Hercules 208* due to expenses incurred to repair leg damage in the Current Quarter. Average operating expenses per rig per day were $39,817 in the Current Quarter compared with $42,998 in the Comparable Quarter.

Inland. Operating expenses for our Inland segment were $6.4 million in the Current Quarter compared with $8.9 million in the Comparable Quarter, a decrease of $2.5 million, or 28%. This decrease is primarily due to lower costs as a result of our cold stacking plan and other cost reduction initiatives, partially offset by increased utilization of our non-stacked barges. Average operating expenses per rig per day were $23,308 in the Current Quarter compared with $29,231 in the Comparable Quarter.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $10.9 million in the Current Quarter compared with $12.4 million in the Comparable Quarter, a decrease of $1.6 million, or 13%. Available days declined to 3,458 in the Current Quarter from 3,842 in the Comparable Quarter due to the transfer of four vessels to our International Liftboats segment in the fourth quarter of 2009. Average operating expenses per vessel per day were $3,139 in the Current Quarter compared with $3,232 in the Comparable Quarter.

International Liftboats. Operating expenses for our International Liftboats segment were $14.9 million for the Current Quarter compared with $9.1 million in the Comparable Quarter, an increase of $5.8 million, or 63%. The increase resulted primarily from the transfer of four vessels to West Africa from the U.S. Gulf of Mexico, the availability of the *Whale Shark* as well as higher expenses related to insurance, equipment rentals and licensing fees. Available days increased to 2,154 in the Current Quarter from 1,729 in the Comparable Quarter related to the availability of the *Whale Shark* and the four vessels transferred from our Domestic Liftboats segment during the fourth quarter of 2009.

Delta Towing. Operating expenses for our Delta Towing segment were $6.4 million for the Current Quarter compared with $5.8 million in the Comparable Quarter, an increase of $0.5 million, or 9%. The increase is primarily due to the increase in activity associated with the Macondo blowout remediation efforts as well as higher insurance costs, partially offset by lower labor costs.

Impairment of Property and Equipment

In June 2009, we entered into an agreement to sell *Hercules 110*, which was cold stacked in Trinidad, and incurred a $26.9 million impairment charge to write-down the rig to its fair value less costs to sell.

Depreciation and Amortization

Depreciation and amortization expense in the Current Quarter was $48.4 million compared with $51.1 million in the Comparable Quarter, a decrease of $2.7 million, or 5%. This decrease resulted primarily from lower amortization of our international contract values and drydocking costs as well as reduced depreciation due to the sale of *Hercules 110* during the third quarter of 2009.

General and Administrative Expenses

General and administrative expenses were relatively flat in the Current Quarter at $14.8 million compared with $15.5 million in the Comparable Quarter, a decrease of $0.7 million, or 4%.

Interest Expense

Interest expense in the Current Quarter was $21.3 million compared with $14.6 million in the Comparable Quarter, an increase of $6.7 million, or 46%. This increase was primarily related to interest expense incurred on our 10.5% Senior Secured Notes issued in October 2009, partially offset by lower interest on our 3.375% Convertible Senior Notes due to our second quarter 2009 retirements. In addition, the increase in interest rates after the Credit Amendment were offset by lower debt balances due to the early retirement of a portion of our term loan in the third and fourth quarters of 2009.

Gain on Early Retirement of Debt, Net

During the Comparable Quarter, we retired $65.8 million aggregate principal amount of the 3.375% Convertible Senior Notes for cash and equity consideration of approximately $40.1 million, resulting in a gain of $13.7 million, net of an associated write-off of a portion of our unamortized issuance costs.

Income Tax Benefit

Our income tax benefit was $4.7 million on a pre-tax loss of $23.7 million, for an effective rate of 19.7%, during the Current Quarter, compared to a benefit of $11.5 million on a pre-tax loss of $23.3 million, for an effective rate of 49.4%, for the Comparable Quarter. The effective tax rate in the Current Quarter decreased due to the reduction in our estimated annual effective tax rate and other discrete items, including various return to provision adjustments.

For the Six Months Ended June 30, 2010 and 2009

Revenues

Consolidated. Total revenues for the six-month period ended June 30, 2010 (the Current Period) were $316.7 million compared with $407.2 million for the six-month period ended June 30, 2009 (the Comparable Period), a decrease of $90.4 million, or 22%. This decrease is further described below.

Domestic Offshore. Revenues for our Domestic Offshore segment were $63.1 million for the Current Period compared with $96.2 million for the Comparable Period, a decrease of $33.0 million, or 34%. This decrease resulted primarily from a 42% decline in average dayrates which contributed an approximate $41 million decrease during the Current Period as compared to the Comparable Period. Partially offsetting this decrease is an increase in operating days to 1,789 days during the Current Period from 1,570 days during the Comparable Period, which contributed to an approximate $8 million increase in revenues.

International Offshore. Revenues for our International Offshore segment were $146.9 million for the Current Period compared with $205.2 million for the Comparable Period, a decrease of $58.3 million, or 28%. This decrease related primarily to *Hercules 156* and *Hercules 170,* which did not work in the Current Period, and a decline in revenue associated with mobilizing *Hercules 205* and *Hercules 206* to the U.S. Gulf of Mexico. Average revenue per rig per day increased to $138,618 in the Current Period from $129,633 in the Comparable Period due primarily to contract mix as the warm-stacked or transferred rigs in the Current Period operated at lower average dayrates during the Comparable Period.

Inland. Revenues for our Inland segment were $9.9 million for the Current Period compared with $13.0 million for the Comparable Period, a decrease of $3.1 million, or 24%. This decrease resulted primarily from a 54% decrease in average dayrates during the Current Period as compared to the Comparable Period, partially offset by increased operating days, 490 days during the Current Period as compared to 298 days during the Comparable Period.

Domestic Liftboats. Revenues from our Domestic Liftboats segment were $29.3 million for the Current Period compared with $41.5 million in the Comparable Period, a decrease of $12.2 million, or 29%. This decrease resulted primarily from the decline in average revenue per vessel per day, $6,936 in the Current Period as compared to $8,498 per vessel per day in the Comparable Period, or a per vessel per day decrease of $1,562. The decrease in average revenue per vessel per day was due to both weaker dayrates on our smaller class vessels and a shift in the mix of vessel class, as we mobilized four larger class vessels to West Africa in the fourth quarter of 2009. In addition, operating days decreased to 4,230 days during the Current Period as compared to 4,883 days during the Comparable Period.

International Liftboats. Revenues for our International Liftboats segment were $53.1 million for the Current Period compared with $39.4 million in the Comparable Period, an increase of $13.8 million, or 35%. This increase resulted primarily from the transfer of four vessels to West Africa from the U.S. Gulf of Mexico which contributed approximately $18.6 million in revenue during the Current Period. Average revenue per liftboat per day increased to $22,164 in the Current Period compared with $20,483 in the Comparable Period while operating days increased to 2,398 days in the Current Period as compared to 1,923 days in the Comparable Period.

Delta Towing. Revenues for our Delta Towing segment were $14.3 million for the Current Period compared with $11.9 million in the Comparable Period, an increase of $2.4 million, or 20%. This increase resulted primarily from an increase in operating days during the Current Period as compared to the Comparable Period, partially offset by a decrease in average vessel dayrates during the Current Period as compared to the Comparable Period.

Operating Expenses

Consolidated. Total operating expenses for the Current Period were $217.0 million compared with $265.3 million in the Comparable Period, a decrease of $48.4 million, or 18%. This decrease is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $76.4 million in the Current Period compared with $95.2 million in the Comparable Period, a decrease of $18.8 million, or 20%. The decrease was driven primarily by 458 fewer available days during the Current Period as compared to the Comparable Period, or a 18% decline, due to our cold stacking of rigs. As a part of our cold stacking plan, we reduced our labor force. Our cold stacking resulted in a reduction to our labor, repairs and maintenance, insurance and catering expenses. Average operating expenses per rig per day were relatively flat in the Current Period compared with the Comparable Period.

International Offshore. Operating expenses for our International Offshore segment were $67.3 million in the Current Period compared with $83.3 million in the Comparable Period, a decrease of $15.9 million, or 19%. This decrease related primarily to *Hercules 156* and *Hercules 170* in warm stack during the Current Period as well as *Hercules 205* and *Hercules 206* being transferred to Domestic Offshore in the first quarter of 2010 and fourth quarter of 2009, respectively. Average operating expenses per rig per day were $39,887 in the Current Period compared with

$47,393 in the Comparable Period.

Inland. Operating expenses for our Inland segment were $12.1 million in the Current Period compared with $29.1 million in the Comparable Period, a decrease of $17.0 million, or 59%. Fourteen of our seventeen barges were cold stacked which reduced our available days from 1,026 in the Comparable Period to 543 in the Current Period. This reduction in available days coupled with the reduction in our labor force significantly reduced the segment s variable operating costs. In addition, the Current Period includes a

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$2.2 million gain on the sale of six of our retired barges. Average operating expenses per rig per day were $22,247 in the Current Period compared with $28,383 in the Comparable Period.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $20.2 million in the Current Period compared with $26.6 million in the Comparable Period, a decrease of $6.4 million, or 24%. This decrease is primarily due to the transfer of four vessels to our International Liftboats segment as well as a reduction in labor costs. Available days declined to 6,878 in the Current Period from 7,712 in the Comparable Period due primarily to the transfer of four vessels to our International Liftboats segment in the fourth quarter of 2009. Operating expenses per vessel per day were $2,932 in the Current Period compared with $3,443 in the Comparable Period.

International Liftboats. Operating expenses for our International Liftboats segment were $29.4 million for the Current Period compared with $17.2 million in the Comparable Period, an increase of $12.1 million, or 70%. The increase resulted primarily from the transfer of four vessels to West Africa from the U.S. Gulf of Mexico, the availability of the *Whale Shark* as well as higher expenses related to labor, insurance, equipment rentals, repairs and maintenance and licensing fees. Available days increased to 4,314 in the Current Period from 3,439 in the Comparable Period related to the availability of the *Whale Shark* and the four vessels transferred from our Domestic Liftboats segment during the fourth quarter of 2009.

Delta Towing. Operating expenses for our Delta Towing segment were $11.6 million for the Current Period compared with $14.0 million in the Comparable Period, a decrease of $2.4 million, or 17%. This decrease is primarily due to lower labor expenses during the Current Period as compared to Comparable Period due to the cold stacking of vessels.

Impairment of Property and Equipment

In June 2009, we entered into an agreement to sell *Hercules 110*, which was cold stacked in Trinidad, and incurred a $26.9 million impairment charge to write-down the rig to its fair value less costs to sell.

Depreciation and Amortization

Depreciation and amortization expense of $98.6 million was relatively flat in the Current Period as compared to the Comparable Period of $99.9 million, a decrease of $1.3 million, or 1%.

General and Administrative Expenses

General and administrative expenses in the Current Period were $27.1 million compared with $31.7 million in the Comparable Period, a decrease of $4.6 million, or 15%. This decrease primarily related to a reduction of approximately $2.1 million in stock-based compensation expense due to a revision of our estimated forfeiture rate during the Current Period and a net reduction of $1.8 million to bad debt expense.

Interest Expense

Interest expense in the Current Period was $43.0 million compared with $30.4 million in the Comparable Period, an increase of $12.6 million, or 42%. This increase was primarily related to interest expense incurred on our 10.5% Senior Secured Notes issued in October 2009, partially offset by lower interest on our 3.375% Convertible Senior Notes due to our second quarter 2009 retirements. In addition, the increase in interest rates after the Credit Amendment were offset by lower debt balances due to the early retirement of a portion of our term loan in the third and fourth quarters of 2009.

Gain on Early Retirement of Debt, Net

During the Comparable Period, we retired $65.8 million aggregate principal amount of the 3.375% Convertible Senior Notes for cash and equity consideration of approximately $40.1 million, resulting in a gain of $13.7 million, net of an associated write-off of a portion of our unamortized issuance costs.

Income Tax Benefit

Our income tax benefit was $30.8 million on a pre-tax loss of $65.7 million, for an effective rate of 46.9%, during the Current Period, compared to a benefit of $14.3 million on a pre-tax loss of $30.6 million, for an effective rate of 46.8%, for the Comparable Period. During the Current Period we effectively reached a compromise settlement with the Mexican tax authorities on certain outstanding tax liabilities that resulted in a net income tax benefit of approximately $6.0 million during the Current Period. Partially offsetting the effect of this adjustment is the reduction in our estimated annual effective tax rate and other discrete items, including various return to provision adjustments recorded in the Current Period.

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Non-GAAP Financial Measures

Regulation G, *General Rules Regarding Disclosure of Non-GAAP Financial Measures* and other SEC regulations define and prescribe the conditions for use of certain Non-Generally Accepted Accounting Principles (Non-GAAP) financial measures. We use various Non-GAAP financial measures such as adjusted operating income (loss), adjusted income (loss) from continuing operations, adjusted diluted earnings (loss) per share from continuing operations, EBITDA and Adjusted EBITDA. EBITDA is defined as net income plus interest expense, income taxes, depreciation and amortization. We believe that in addition to GAAP based financial information, Non-GAAP amounts are meaningful disclosures for the following reasons: (i) each are components of the measures used by our board of directors and management team to evaluate and analyze our operating performance and historical trends, (ii) each are components of the measures used by our management team to make day-to-day operating decisions, (iii) the Credit Agreement contains covenants that require us to maintain a total leverage ratio and a consolidated fixed charge coverage ratio, which contain Non-GAAP adjustments as components, (iv) each are components of the measures used by our management to facilitate internal comparisons to competitors results and the shallow-water drilling and marine services industry in general, (v) results excluding certain costs and expenses provide useful information for the understanding of the ongoing operations without the impact of significant special items, and (vi) the payment of certain bonuses to members of our management is contingent upon, among other things, the satisfaction by the Company of financial targets, which may contain Non-GAAP measures as components. We acknowledge that there are limitations when using Non-GAAP measures. The measures below are not recognized terms under GAAP and do not purport to be an alternative to net income as a measure of operating performance or to cash flows from operating activities as a measure of liquidity. EBITDA and Adjusted EBITDA are not intended to be a measure of free cash flow for management s discretionary use, as it does not consider certain cash requirements such as tax payments and debt service requirements. In addition, the EBITDA and Adjusted EBITDA amounts presented in the following table should not be used for covenant compliance purposes as these amounts could differ materially from the amounts ultimately calculated under our Credit Agreement. Because all companies do not use identical calculations, the amounts below may not be comparable to other similarly titled measures of other companies.

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The following tables present a reconciliation of the GAAP financial measures to the corresponding adjusted financial measures (in thousands, except per share amounts):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Operating Loss	$ (5,574)	$ (25,829)	$ (25,918)	$ (16,720)
Adjustments:				
Property and equipment impairment		26,882		26,882
Total adjustments		26,882		26,882
Adjusted Operating Income (Loss)	$ (5,574)	$ 1,053	$ (25,918)	$ 10,162
Loss from Continuing Operations	$ (18,984)	$ (11,787)	$ (34,940)	$ (16,298)
Adjustments:				
Property and equipment impairment		26,882		26,882
Gain on early retirement of debt, net		(13,747)		(13,747)
Tax impact of adjustments		(8,966)		(8,966)
Total adjustments		4,169		4,169
Adjusted Loss from Continuing Operations	$ (18,984)	$ (7,618)	$ (34,940)	$ (12,129)
Diluted Loss per Share from Continuing Operations	$ (0.17)	$ (0.13)	$ (0.30)	$ (0.18)
Adjustments:				
Property and equipment impairment		0.30		0.30
Gain on early retirement of debt, net		(0.15)		(0.16)
Tax impact of adjustments		(0.11)		(0.10)
Total adjustments		0.04		0.04
Adjusted Diluted Loss per Share from Continuing Operations	$ (0.17)	$ (0.09)	$ (0.30)	$ (0.14)
Loss from Continuing Operations	$ (18,984)	$ (11,787)	$ (34,940)	$ (16,298)
Interest expense	21,259	14,561	42,998	30,350
Income tax benefit	(4,666)	(11,510)	(30,807)	(14,335)
Depreciation and amortization	48,350	51,091	98,604	99,937
EBITDA	45,959	42,355	75,855	99,654
Adjustments:				
Property and equipment impairment		26,882		26,882
Gain on early retirement of debt, net		(13,747)		(13,747)

Total adjustments		13,135		13,135
Adjusted EBITDA	$ 45,959	$ 55,490	$ 75,855	$ 112,789

CRITICAL ACCOUNTING POLICIES

Critical accounting policies are those that are important to our results of operations, financial condition and cash flows and require management s most difficult, subjective or complex judgments. Different amounts would be reported under alternative assumptions. We have evaluated the accounting policies used in the preparation of the unaudited consolidated financial statements and related notes appearing elsewhere in this quarterly report. We apply those accounting policies that we believe best reflect the underlying business and economic events, consistent with accounting principles generally accepted in the United States. We believe that our policies are generally consistent with those used by other companies in our industry. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

We periodically update the estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. During recent periods, there has been substantial volatility and a decline in commodity prices. In addition, there has been uncertainty in the capital markets and available financing has been limited.

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These conditions adversely impact the business of our customers, and in turn our business. This could result in changes to estimates used in preparing our financial statements, including the assessment of certain of our assets for impairment.

We believe that our more critical accounting policies include those related to property and equipment, revenue recognition, income tax, allowance for doubtful accounts, deferred charges, stock-based compensation, cash and cash equivalents and intangible assets. Inherent in such policies are certain key assumptions and estimates. For additional information regarding our critical accounting policies, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009.

OUTLOOK

Offshore

In general, demand for our drilling rigs is a function of our customers capital spending plans, which are largely driven by current commodity prices and their expectations of future commodity prices. Demand in the U.S. Gulf of Mexico is particularly driven by natural gas prices, with demand internationally typically driven by oil prices. U.S. natural gas prices tend to be highly volatile. Since mid-2008, the spot price for Henry Hub natural gas has ranged from a high of $13.31 per MMBtu on July 2, 2008, to a low of $1.83 in September 4, 2009. As of July 23, 2010, the spot price for Henry Hub natural gas was $4.69 per MMBtu, and the twelve month strip, or the average of the next twelve month s futures contract, was $4.97 per MMBtu. A myriad of factors combined to cause natural gas prices to decline to extremely depressed levels during the late summer and fall of 2009 from its recent high in mid-2008. The worldwide economic downturn resulted in reduced energy consumption, creating a sharp decline in the demand for natural gas. On the supply side, increases in onshore production in the U.S., driven by a significant increase in onshore drilling activity through mid-2008 and increased activity in prolific unconventional natural gas basins also put downward pressure on natural gas prices. Growing deepwater production and potential increased deliveries of liquefied natural gas are additional factors which weighed on natural gas prices.

Natural gas prices have recovered from the September 2009 low, but still remain depressed. Expectations for a subdued economic rebound leading to a recovery in industrial demand for natural gas have been overshadowed by the current natural gas supply overhang in the United States. The decline in North American drilling activity from its recent peak has not led to the production declines many had expected thus far, and drilling activity has since increased. All of these factors, together with weather, will likely remain key drivers in the natural gas market for the foreseeable future.

Oil prices also declined significantly from mid-2008 to early 2009 as a result of the anticipated effects of global economic weakness, increase in oil inventories relative to consumption and a strengthening in the U.S. dollar. The price of West Texas intermediate crude (WTI) declined from $145.29 on July 3, 2008, to a multi-year low of $31.41 on December 22, 2008. However, it has since recovered meaningfully to $78.73 as of July 23, 2010.

During 2009, the Company s domestic segments experienced the effects of a historic decline in U.S. focused exploration and production capital spending. Based on capital spending surveys from various third party sources, domestic focused exploration and production capital spending was expected to increase in 2010. However, in the wake of the Macondo blowout in the U.S. Gulf of Mexico, regulatory changes imposed by the Department of Interior and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEM formerly the Minerals Management Service) have had an adverse impact on our customers ability to timely obtain the necessary drilling permits, and as a result, together with other regulatory uncertainty, have adversely affected demand for our drilling rigs in the region. While we did not experience a material impact to our financial results during the second quarter of 2010, a prolonged continuation of the regulatory delays in the permit approval process would likely have a material impact to our Domestic Offshore segment s financial results going forward. Further, depending on the severity of the decline in domestic shallow water drilling activity, the effectiveness of our cost reduction and other mitigating measures and the profitability of our other business segments, these events could significantly impact our financial results and could affect our ability to continue to comply with the financial covenants contained in our Credit Agreement.

Furthermore, activity levels in the Domestic Offshore segment will likely continue to be highly dependent upon natural gas prices, among other factors as our domestic focused customers often quickly adjust their drilling plans to changes in the outlook. Additionally, operators focused in the U.S., have increasingly been deploying incremental capital to other less mature basins such as the various shale formations, a trend that is expected to continue for the foreseeable future. Further, during 2009, we experienced an increase in seasonality with certain operators completing their drilling programs during the first half of the year, so as to avoid drilling during the Atlantic hurricane season. A continuation of this trend could be negative for our operating results as it would be difficult to adjust our cost structure to account for such seasonality.

While international spending programs are much longer-term in nature than typical U.S. drilling programs, and the customers tend to have greater financial resources, international capital spending also declined in 2009, but to a lesser degree, following nine years of growth. However, international focused capital spending is also expected to modestly increase during 2010.

While increased capital spending may lead to additional demand for jackup drilling rigs, the offshore drilling industry is still expected to have excess capacity of jackup drilling rigs in 2010, given the current number of idle jackup rigs and expected growth in supply. As of July 23, 2010, there were a total of 81 jackup rigs in the U.S. Gulf of Mexico, with 34 contracted, 14 stacked ready and 33 in the shipyard or cold stacked. Cold stacked rigs are generally not marketed and in some cases would require significant capital to reactivate. Also as of July 23, 2010, there were 375 jackup rigs located in international regions, with 305 contracted, 33 stacked ready, 1 on standby, 1 in port and 35 in the shipyard or cold stacked. Further, 53 new jackup rigs are either under construction or on order for delivery through 2012, of which 21 are scheduled to be delivered during the remainder of 2010. Of the remaining 32 rigs that are under construction, work has been suspended on 11 of these units. However, we anticipate, the majority of the jackups under construction will likely ultimately be delivered and compete with our fleet. As a result of generally higher dayrates, longer duration contracts and lower insurance costs which are prevalent internationally, among other factors, we believe the vast majority of the newbuild jackup rigs will target international regions rather than the U.S. Gulf of Mexico. Our ability to secure new contracts for our international fleet or to expand our international drilling operations may be limited by the increased supply of newbuild jackup rigs.

While potential increases in capital spending may lead to improving international jackup rig demand in 2010, the expected newbuild deliveries, coupled with relatively large number of idle marketed jackup rigs, represent a significant amount of over capacity relative to current demand and could cause additional downward pressure on dayrates, or at a minimum, make it challenging for the industry to see any meaningful improvement in dayrates.

Nonetheless, a number of other factors could result in improved market conditions for future drilling activity for the longer term. First, with steep initial decline rates in many North American natural gas basins and a meaningful reduction in the rig count from the peak, the recent strong natural gas market production growth could slow or even reverse. With respect to international markets, which are typically driven by crude oil prices, the lack of any significant oil production growth over the last five years, despite a substantial increase in international exploration and production capital spending over this period, leads us to believe that further production growth will be difficult to achieve without significant increases in exploration and production spending or technological improvements. Further, the halt of deepwater drilling activity in the wake of the Macondo blowout in the U.S. Gulf of Mexico on April 20, 2010, may have a negative long term impact on the supply of crude oil from the region.

The offshore drilling market remains highly competitive and cyclical, and it has historically been difficult to forecast future market conditions. While future commodity price expectations have typically been a key driver for demand for drilling rigs, other factors also affect our customers drilling programs, including the quality of drilling prospects, exploration success, relative production costs, availability of insurance, and political and regulatory environments, including the ability and timeliness of obtaining drilling permits from the appropriate regulatory bodies as well as access to offshore leases. Additionally, the offshore drilling business has historically been cyclical, marked by periods of low demand, excess rig supply and low dayrates, followed by periods of high demand, short rig supply and increasing dayrates. These cycles have been volatile and are subject to rapid change.

Inland

The activity for inland barge drilling in the U.S. generally follows the same drivers as drilling in the U.S. Gulf of Mexico with activity following operators expectations of prices for natural gas and crude oil. Barge rig drilling activity historically lags activity in the U.S. Gulf of Mexico due to a number of factors such as the lengthy permitting process that operators must go through prior to drilling a well in Louisiana, where the majority of our inland drilling takes place. The predominance of smaller independent operators active in inland waters also adds to the volatility of this region.

Inland barge drilling activity has slowed dramatically over the past three years and dayrates have declined as a result of the number of the key operators that have curtailed or ceased their activity in the inland market for various reasons, including lack of funding, lack of drilling success and re-allocation of capital to other onshore basins. Activity has increased recently, with a higher percentage of the drilling focused on crude oil. As of July 20, 2010, all three of our marketed inland barges had contracts for work. While we may have some increased activity for our inland barges based on stronger capital budgets and improved commodity prices, we expect activity levels to remain very low during 2010 versus historic norms.

Liftboats

Demand for liftboats is typically a function of our customers demand for platform inspection and maintenance, well maintenance, offshore construction, well plugging and abandonment, and other related activities. Although activity levels for liftboats are not as closely correlated to movement in commodity prices as for offshore drilling rigs, commodity prices are still a key driver of the demand for liftboats. Despite the production maintenance related nature of the majority of the work, some of the work may be deferred from time to time.

Following the active 2005 hurricane season, which caused tremendous damage to the infrastructure in the U.S. Gulf of Mexico, liftboat utilization and dayrates in the region were stronger than historical levels for approximately two years. As a result of this robust activity, many of our competitors ordered new liftboats and approximately 24 have been delivered for work in the U.S. Gulf of Mexico since January 2007. As of June 2010, we believe that there are another nine liftboats under construction or on order in the U.S. that could potentially be delivered through 2011. Once delivered, these liftboats may further impact the demand and utilization of our domestic liftboat fleet. However, some of these new liftboats in the U.S. Gulf of Mexico could be offset by mobilizations to meet growing demand in other regions. During the second quarter of 2010, liftboat utilization improved in the U.S. Gulf of Mexico largely as a result of clean up efforts related to the Macondo blowout. A continuation of such clean up efforts could sustain higher utilization levels for liftboats in the region. Additionally, increased federal regulation could provide a catalyst for increased well plugging and abandoning activity.

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Our customers growth in international capital spending for the last several years, coupled with an aging infrastructure and significant increases in the cost of alternatives for servicing this infrastructure, has generally resulted in strong demand for our liftboats in West Africa. As international markets mature and the focus shifts from exploration to development in locations such as West Africa, the Middle East and Southeast Asia, we expect to experience strong demand growth for liftboats. We anticipate that there may be contract opportunities in international locations for liftboats currently working in the U.S. Gulf of Mexico and for newly constructed liftboats. In 2008 we mobilized two of our liftboats to the Middle East from the U.S. Gulf of Mexico and in 2009 we mobilized four liftboats to West Africa from the U.S. Gulf of Mexico. While we believe that international demand for liftboats will continue to increase over the longer term, political instability in certain regions may negatively impact our customers capital spending plans.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for the six-month period ended June 30, 2010 are as follows (in millions):

Net Cash Used in Operating Activities	$ (33.5)
Net Cash Provided by (Used in) Investing Activities:	
Additions of Property and Equipment	(11.0)
Deferred Drydocking Expenditures	(7.6)
Proceeds from Sale of Assets, Net	10.0
Increase in Restricted Cash	(3.4)
Total	(12.0)
Net Cash Provided by (Used in) Financing Activities:	
Long-term Debt Repayments	(4.0)
Excess Tax Benefits from Stock-Based Arrangements	0.4
Total	(3.6)
Net Decrease in Cash and Cash Equivalents	$ (49.1)

Sources of Liquidity and Financing Arrangements

Our liquidity is comprised of cash on hand, cash from operations and availability under our revolving credit facility. We also maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If we issue any debt securities off the shelf or otherwise incur debt, we would generally be required to allocate the proceeds of such debt to repay or refinance existing debt. We currently believe we will have adequate liquidity to meet the minimum liquidity requirement under our Credit Agreement that governs our $478.8 million term loan and $175.0 million revolving credit facility and to fund our operations. However, to the extent we do not generate sufficient cash from operations we may need to raise additional funds through debt, equity offerings or the sale of assets to meet certain covenants under the Credit Agreement, to refinance existing debt or for general corporate purposes. In July 2012, our $175.0 million revolving credit facility matures. To the extent we are unsuccessful in extending the maturity or entering into a new revolving credit facility, our liquidity would be negatively impacted. In June 2013, we may be required to settle our 3.375% Convertible Senior Notes. As of June 30, 2010, the notional amount of these notes outstanding was $95.9 million. Additionally, our term loan matures in July 2013 and currently requires a balloon payment of $464.1 million at maturity. We intend to meet these obligations through one or more of the following: cash flow from operations, asset sales, debt refinancing and future debt or equity offerings.

Our Credit Agreement requires that we meet certain financial ratios and tests, which we currently meet. Our failure to comply with such covenants would result in an event of default under the Credit Agreement. An event of default could prevent us from borrowing under the revolving credit facility, which would in turn have a material adverse effect on our available liquidity. Additionally, an event of default could result in us having to immediately repay all amounts outstanding under the term loan facility, the revolving credit facility, our 10.5% Senior Secured Notes and our 3.375% Convertible Senior Notes and in the foreclosure of liens on our assets.

Cash Requirements and Contractual Obligations

Debt

Our current debt structure is used to fund our business operations.

In July 2007, we terminated all prior facilities and entered into a new $1,050.0 million credit facility with a syndicate of financial institutions, consisting of a $900.0 million term loan which matures on July 11, 2013 and a $150.0 million revolving credit facility which matures on July 11, 2012 (the Credit Agreement). On April 28, 2008, we entered into an agreement to increase the revolving credit facility to $250.0 million.

On July 27, 2009, we amended the Credit Agreement (the Credit Amendment) which governs our term loan and revolving credit facility. The Credit Amendment reduced the revolving credit facility by $75.0 million to $175.0 million. As a result of the Credit Amendment and payments on the term loan, the credit facility currently consists of a $478.8 million term loan and a $175.0 million revolving credit facility. The Credit Amendment establishes a minimum London Interbank Offered Rate (LIBOR) of 2.00% for Eurodollar Loans, a minimum rate of 3.00% with respect to Alternative Base Rate (ABR) Loans, and increases the margin applicable to Eurodollar Loans to 4.00% and ABR Loans to 3.00%. Under the Credit Amendment, the commitment fee on the revolving credit facility increased from 0.375% to 1.00% and the letter of credit fee with respect to the undrawn amount of each letter of credit issued under the revolving credit facility increased from 1.75% to 4.00% per annum.

The Credit Amendment also modifies certain provisions of the Credit Agreement to, among other things:

Eliminate the requirement that we comply with the total leverage ratio financial covenant for the nine month period commencing October 1, 2009 and ending on June 30, 2010.

Amend the maximum total leverage ratio that we must comply with to the following schedule. The total leverage ratio for any test period is calculated as the ratio of consolidated indebtedness on the test date to consolidated EBITDA for the trailing twelve months, all as defined in the Credit Agreement.

Test Date	**Maximum Total Leverage Ratio**
September 30, 2010	8.00 to 1.00
December 31, 2010	7.50 to 1.00
March 31, 2011	7.00 to 1.00
June 30, 2011	6.75 to 1.00
September 30, 2011	6.00 to 1.00
December 31, 2011	5.50 to 1.00
March 31, 2012	5.25 to 1.00
June 30, 2012	5.00 to 1.00
September 30, 2012	4.75 to 1.00
December 31, 2012	4.50 to 1.00
March 31, 2013	4.25 to 1.00
June 30, 2013	4.00 to 1.00

- At June 30, 2010, our total leverage ratio was 8.09. There is no maximum total leverage requirement for the period ended June 30, 2010.

Require us to maintain a minimum level of liquidity, measured as the amount of unrestricted cash and cash equivalents we have on hand and availability under the revolving credit facility, of (i) $100.0 million for the period between October 1, 2009 through December 31, 2010, (ii) $75.0 million during calendar year 2011 and

(iii) $50.0 million thereafter. As of June 30, 2010, as calculated pursuant to our Credit Agreement, our total liquidity was $256.7 million.

Revise the consolidated fixed charge coverage ratio definition and reduce the minimum fixed charge coverage ratio that we must maintain to the following schedule:

Period		**Fixed Charge Coverage Ratio**
July 1, 2009	December 31, 2011	1.00 to 1.00
January 1, 2012	March 31, 2012	1.05 to 1.00
April 1, 2012	June 30, 2012	1.10 to 1.00
July 1, 2012 and thereafter		1.15 to 1.00

- The consolidated fixed charge coverage ratio for any test period is defined as the sum of consolidated EBITDA for the test period plus an amount that may be added for the purpose of calculating the ratio for such test period, not to exceed $130.0 million in total during the term of the credit facility, to consolidated fixed charges for the test period, all as defined in the Credit Agreement. As of June 30, 2010, our fixed charge coverage ratio was 1.0.

Require mandatory prepayments of debt outstanding under the Credit Agreement with 50% of excess cash flow as defined in the Credit Agreement for the fiscal years ending December 31, 2010, 2011 and 2012, and with proceeds from:

- unsecured debt issuances, with the exception of refinancing;
- secured debt issuances;
- casualty events not used to repair damaged property;
- sales of assets in excess of $25 million annually; and
- unless we have achieved a specified leverage ratio, 50% of proceeds from equity issuances, excluding those for permitted acquisitions or to meet the minimum liquidity requirements.

The availability under the $175.0 million revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay our term loan. As of June 30, 2010, no amounts were outstanding and $10.0 million in stand-by letters of credit had been issued under the revolving credit facility, therefore the remaining availability under this revolving credit facility was $165.0 million. Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.2 million, with the balance due on July 11, 2013. All borrowings under the revolving credit facility mature on July 11, 2012. Interest payments on both the revolving and term loan facility are due at least on a quarterly basis and in certain instances, more frequently. As of June 30, 2010, $478.8 million was outstanding on the term loan facility and the interest rate was 6.00%. The annualized effective interest rate was 9.07% for the six months ended June 30, 2010 after giving consideration to revolver fees and derivative activity.

Other covenants contained in the Credit Agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, stock repurchases and redemptions, other restricted payments, debt issuances, liens, investments, convertible notes repurchases and affiliate transactions. The Credit Agreement also contains a provision under which an event of default on any other indebtedness exceeding $25.0 million would be considered an event of default under our Credit Agreement.

In May 2008 and July 2007, we entered into derivative instruments with the purpose of hedging future interest payments on our term loan facility. In May 2008, we entered into a floating-to-fixed interest rate swap with varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million which was settled on December 31, 2009. We received an interest rate of three-month LIBOR and paid a fixed coupon of 2.980% over six quarters. The terms and settlement dates of the swap matched those of the term loan through July 27, 2009, the date of the Credit Amendment. In July 2007, we entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010 with a ceiling of 5.75% and a floor of 4.99%. The counterparty is obligated to pay us in any quarter that actual LIBOR resets above 5.75% and we pay the counterparty in any quarter that actual LIBOR resets below 4.99%. The terms and settlement dates of the collar matched those of the term loan through July 27, 2009, the date of the Credit Amendment. As a result of the inclusion of a LIBOR floor in the Credit Agreement, we do not believe, as of July 27, 2009 and on an ongoing basis, that the interest rate swap and collar will be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, we have prospectively discontinued cash flow hedge accounting for the interest rate swap and collar as of July 27, 2009 and no longer apply cash flow hedge accounting to these instruments. Because cash flow hedge accounting will not be applied to these instruments, changes in fair value related to the interest rate swap and collar subsequent to July 27, 2009 have been recorded in earnings and will be on a go-forward basis. As a result of discontinuing the cash flow hedging relationship, we recognized an increase in fair value of $0.1 million and a decrease in fair value of $0.3 million related to the hedge ineffectiveness of our collar as Interest Expense in our Consolidated Statements of Operations for the three and six months ended June 30, 2010, respectively. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the three and six months ended June 30, 2009 related to interest rate derivative instruments. The change in the fair value of our hedging instruments resulted in a decrease in derivative liabilities of $3.3 million during the six months ended June 30, 2010. We had net unrealized gains on hedge transactions of $1.9 million, net of tax of $1.1 million, and $4.0 million, net of tax of $2.2 million for the three and six months ended June 30, 2010, respectively and $2.0 million, net of tax of $1.1 million, and $1.6 million, net of tax of $0.9 million for the three and six months ended June 30, 2009, respectively. Overall, our interest expense was increased by $2.9 million and $6.4 million during the three and six months ended June 30, 2010, respectively and $4.0 million and $8.4 million during the three and six months ended June 30, 2009, respectively, as a result of our interest rate derivative instruments.

On October 20, 2009, we completed an offering of $300.0 million of senior secured notes at a coupon rate of 10.5% (10.5% Senior Secured Notes) with a maturity in October 2017. The interest on the notes is payable in cash semi-annually in arrears on April 15 and October 15 of each year, to holders of record at the close of business on April 1 or October 1. Interest on the notes will be computed on the basis of a 360-day year of twelve 30-day months. The notes were sold at 97.383% of their face amount to yield 11.0% and were recorded at their discounted amount, with the discount to be amortized over the life of the notes. We used the net proceeds of approximately $284.4 million from the offering to repay a portion of the indebtedness outstanding under our term loan facility. As of June 30, 2010, $300.0 million notional amount of the 10.5% Senior Secured Notes was outstanding. The carrying amount of the 10.5% Senior Secured Notes was $292.6 million at June 30, 2010.

The notes are guaranteed by all of our existing and future restricted subsidiaries that incur or guarantee indebtedness under a credit facility, including our existing credit facility. The notes are secured by liens on all collateral that secures our obligations under our secured credit facility, subject to limited exceptions. The liens securing the notes share on an equal and ratable first priority basis with liens securing our credit facility. Under the intercreditor agreement, the collateral agent for the lenders under our secured credit facility is generally entitled to sole control of all decisions and actions.

All the liens securing the notes may be released if our secured indebtedness, other than these notes, does not exceed the lesser of $375.0 million and 15.0% of our consolidated tangible assets. We refer to such a release as a collateral suspension. If a collateral suspension is in effect, the notes and the guarantees will be unsecured, and will effectively rank junior to our secured indebtedness. If, after any such release of liens on collateral, the aggregate principal amount of our secured indebtedness, other than these notes, exceeds the greater of $375.0 million and 15.0% of our consolidated tangible assets, as defined in the indenture, then the collateral obligations of the Company and guarantors will be reinstated and must be complied with within 30 days of such event.

The indenture governing the notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- make other restricted payments or investments;
- sell assets;
- create liens;
- enter into agreements that restrict dividends and other payments by restricted subsidiaries;
- engage in transactions with our affiliates; and
- consolidate, merge or transfer all or substantially all of our assets.

The indenture governing the notes also contains a provision under which an event of default by us or by any restricted subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default is: a) caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

Prior to October 15, 2012, we may redeem the notes with the net cash proceeds of certain equity offerings, at a redemption price equal to 110.50% of the aggregate principal amount plus accrued and unpaid interest; provided, that (i) after giving effect to any such redemption, at least 65% of the notes originally issued would remain outstanding immediately after such redemption and (ii) we make such redemption not more than 90 days after the consummation of such equity offering. In addition, prior to October 15, 2013, we may redeem all or part of the notes at a price equal to 100% of the aggregate principal amount of notes to be redeemed, plus the applicable premium, as defined in the indenture, and accrued and unpaid interest.

On or after October 15, 2013, we may redeem the notes, in whole or part, at the redemption prices set forth below, together with accrued and unpaid interest to the redemption date.

Year	Optional Redemption Price
2013	105.2500%
2014	102.6250%
2015	101.3125%
2016 and thereafter	100.0000%

If we experience a change of control, as defined, we must offer to repurchase the notes at an offer price in cash equal to 101% of their principal amount, plus accrued and unpaid interest. Furthermore, following certain asset sales, we may be required to use the proceeds to offer to repurchase the notes at an offer price in cash equal to 100% of their principal amount, plus accrued and unpaid interest.

On June 3, 2008, we completed an offering of $250.0 million convertible senior notes at a coupon rate of 3.375% (3.375% Convertible Senior Notes) with a maturity in June 2038. As of June 30, 2010, $95.9 million notional amount of the $250.0 million 3.375% Convertible Senior Notes was outstanding. The carrying amount of the 3.375% Convertible Senior Notes was $84.7 million at June 30, 2010.

The interest on the 3.375% Convertible Senior Notes is payable in cash semi-annually in arrears, on June 1 and December 1 of each year until June 1, 2013, after which the principal will accrete at an annual yield to maturity of 3.375% per year. We will also pay contingent interest during any six-month interest period commencing June 1, 2013, for which the trading price of these notes for a specified period of time equals or exceeds 120% of their accreted principal amount. The notes will be convertible under certain circumstances into shares of our common stock (Common Stock) at an initial conversion rate of 19.9695 shares of Common Stock per $1,000 principal amount of notes, which is equal to an initial conversion price of approximately $50.08 per share. Upon conversion of a note, a holder will receive, at our election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At June 30, 2010, the number of conversion shares potentially issuable in relation to our 3.375% Convertible Senior Notes was 1.9 million. We may redeem the notes at our option beginning June 6, 2013, and holders of the notes will have the right to require us to repurchase the notes on June 1, 2013 and certain dates thereafter or on the occurrence of a fundamental change.

The indenture governing the 3.375% Convertible Senior Notes contains a provision under which an event of default by us or by any subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default: a) is caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

In April 2009, we repurchased $20.0 million aggregate principal amount of the 3.375% Convertible Senior Notes for a cost of $6.1 million, resulting in a gain of $10.7 million. In addition, we expensed $0.4 million of unamortized issuance costs in connection with the retirement. In June 2009, we retired $45.8 million aggregate principal amount of our 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share and payment of accrued interest, resulting in a gain of $4.4 million. In addition, we expensed $1.0 million of unamortized issuance costs in connection with the retirement. The settlement consideration was allocated to the extinguishment of the liability component in an amount equal to the fair value of that component immediately prior to extinguishment, with the difference between this allocation and the net carrying amount of the liability component and unamortized debt issuance costs recognized as a gain or loss on debt extinguishment. If there would have been any remaining settlement consideration, it would have been allocated to the reacquisition of the equity component and recognized as a reduction of Stockholders Equity.

The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. The following table provides the carrying value and fair value of our long-term debt instruments:

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility, due July 2013	$ 478.8	$ 421.4	$ 482.9	$ 468.4
10.5% Senior Secured Notes, due October 2017	292.6	265.9	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	84.7	70.0	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.4	3.5	3.0

In April 2010, we completed the annual renewal of all of our key insurance policies. Our primary marine package provides for hull and machinery coverage for our rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is $2.1 billion. The marine package includes protection and indemnity and maritime employers liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employers liability coverage) of $5.0 million per occurrence with excess liability coverage up to $200.0 million. The marine package also provides coverage for cargo and charter s legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of $100.0 million for property damage and removal of debris liability coverage. We also procured an additional $75.0 million excess policy for removal of debris and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of $1.0 million, and $1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is $25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy with a $3.0 million deductible providing limits as required by applicable law, including the Oil Pollution Act of 1990. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, we have separate policies providing coverage for onshore foreign and domestic general liability, employer s liability, auto liability and non-owned aircraft liability, with customer deductibles and coverage as well as a separate primary marine package for our Delta Towing business.

In 2010, in connection with the renewal of certain of our insurance policies, we entered into an agreement to finance a portion of our annual insurance premiums. Approximately $24.1 million was financed through this arrangement, and $21.7 million was outstanding at June 30, 2010. The interest rate on the note was 3.79% and it is scheduled to mature in March 2011. Additionally, there was $0.2 million outstanding on the $1.9 million note related to the 2009 insurance renewals for our Delta Towing business. The interest rate on this note is 3.75% and it is scheduled to mature in July 2010.

We are self-insured for the deductible portion of our insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of our insurance coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. However, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences.

Common Stock Offering

In September 2009, we raised approximately $82.3 million in net proceeds from an underwritten public offering of 17,500,000 shares of our Common Stock. In addition, on October 9, 2009, we sold an additional 1,313,590 shares of our Common Stock pursuant to the partial exercise of the underwriters over-allotment option and raised an additional $6.3 million in net proceeds. We used a portion of the net proceeds from these sales of Common Stock to repay a portion of our outstanding indebtedness under our term loan facility.

Capital Expenditures

We expect to spend approximately $40 million on capital expenditures and drydocking, during the remainder of 2010. Planned capital expenditures are generally maintenance and regulatory in nature and do not include refurbishment or upgrades to our rigs, liftboats, and other marine vessels. Should we elect to reactivate cold stacked rigs or upgrade and refurbish selected rigs or liftboats our capital expenditures may increase. Reactivations, upgrades and refurbishments are subject to our discretion and will depend on our view of market conditions and our cash flows.

Costs associated with refurbishment or upgrade activities which substantially extend the useful life or operating capabilities of the asset are capitalized. Refurbishment entails replacing or rebuilding the operating equipment. An upgrade entails increasing the operating capabilities of a rig or liftboat. This can be accomplished by a number of means, including adding new or higher specification equipment to the unit, increasing the water depth capabilities or increasing the capacity of the living quarters, or a combination of each.

We are required to inspect and drydock our liftboats on a periodic basis to meet U.S. Coast Guard requirements. The amount of expenditures is impacted by a number of factors, including, among others, our ongoing maintenance expenditures, adverse weather, changes in regulatory requirements and operating conditions. In addition, from time to time we agree to perform modifications to our rigs and liftboats as part of a contract with a customer. When market conditions allow, we attempt to recover these costs as part of the contract cash flow.

From time to time, we may review possible acquisitions of rigs, liftboats or businesses, joint ventures, mergers or other business combinations, and we may have outstanding from time to time bids to acquire certain assets from other companies. We may not, however, be successful in our acquisition efforts. We are generally restricted by our Credit Agreement from making acquisitions for cash consideration, except to the extent the acquisition is funded by an issuance of our stock or cash proceeds from the issuance of stock, or unless we are in compliance with our financial covenants as they existed prior to the Credit Amendment. If we acquire additional assets, we would expect that the ongoing capital expenditures for our company as a whole would increase in order to maintain our equipment in a competitive condition.

Our ability to fund capital expenditures would be adversely affected if conditions deteriorate in our business.

Off-Balance Sheet Arrangements

Guarantees

Our obligations under the credit facility and 10.5% Senior Secured Notes are secured by liens on a majority of our vessels and substantially all of our other personal property. Substantially all of our domestic subsidiaries, and several of our international subsidiaries, guarantee the obligations under the credit facility and 10.5% Senior Secured Notes and have granted similar liens on several of their vessels and substantially all of their other personal property.

Bank Guarantees, Letters of Credit, and Surety Bonds

We execute bank guarantees, letters of credit and surety bonds in the normal course of business. While these obligations are not normally called, these obligations could be called by the beneficiaries at any time before the expiration date should we breach certain contractual or payment obligations. As of June 30, 2010, we had $61.7 million in a bank guarantee, letters of credit and surety bonds outstanding, consisting of a $1.0 million unsecured bank guarantee, a $0.1 million unsecured outstanding letter of credit, $10.0 million letters of credit outstanding under our revolver and $50.6 million outstanding in surety bonds that guarantee our performance as it relates to our drilling contracts, tax and other obligations primarily in Mexico and the U.S. If the beneficiaries called the bank guarantee, letters of credit and surety bonds, the called amount would become an on-balance sheet liability, and we would be required to settle the liability with cash on hand or through borrowings under our available line of credit. As of June 30, 2010, we have restricted cash of $7.0 million to support surety bonds primarily related to the Company s Mexico and U.S. operations. In July 2010, we increased our restricted cash balance by $6.1 million as additional collateral to support surety bonds related to our Mexico and U.S. operations. Additionally, in July 2010, a $13.2 million surety bond related to the Mexico tax assessment was released.

Contractual Obligations

Our contractual obligations and commitments principally include obligations associated with our outstanding indebtedness, certain income tax liabilities, surety bonds, letters of credit, future minimum operating lease obligations, purchase commitments and management compensation obligations. Except for the following, during the first six months of 2010, there were no material changes outside the ordinary course of business in the specified contractual obligations.

- Settled $5.3 million of insurance notes payable outstanding at December 31, 2009; and

- Financed $24.1 million related to the renewal of certain of our insurance policies.

For additional information about our contractual obligations as of December 31, 2009, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Contractual Obligations in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009.

Accounting Pronouncements

See Note 12 to our condensed consolidated financial statements included elsewhere in this report.

FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this quarterly report that address outlook, activities, events or developments that we expect, project, believe or anticipate will or may occur in the future are forward-looking statements. These include such matters as:

- our levels of indebtedness, covenant compliance and access to capital under current market conditions;

- our ability to enter into new contracts for our rigs and liftboats and future utilization rates and dayrates for the units;

- our ability to renew or extend our long-term international contracts, or enter into new contracts, when such contracts expire;

- demand for our rigs and our liftboats and our earnings;

- activity levels of our customers and their expectations of future energy prices and ability to obtain drilling permits;

- sufficiency and availability of funds for required capital expenditures, working capital and debt service;

levels of reserves for accounts receivable;

success of our cost cutting measures and plans to dispose of certain assets;

expected completion times for our refurbishment and upgrade projects;

our plans to increase international operations;

expected useful lives of our rigs and liftboats;

future capital expenditures and refurbishment, reactivation, transportation, repair and upgrade costs;

our ability to effectively reactivate rigs that we have recently stacked;

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liabilities and restrictions under coastwise laws of the United States and regulations protecting the environment;

expected outcomes of litigation, claims and disputes and their expected effects on our financial condition and results of operations; and

expectations regarding offshore drilling activity and dayrates, market conditions, demand for our rigs and liftboats, operating revenues, operating and maintenance expense, insurance coverage, insurance expense and deductibles, interest expense, debt levels and other matters with regard to outlook.

We have based these statements on our assumptions and analyses in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Forward-looking statements by their nature involve substantial risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such statements. Although it is not possible to identify all factors, we continue to face many risks and uncertainties. Among the factors that could cause actual future results to differ materially are the risks and uncertainties described under Risk Factors in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009, Item 1A of Part II of our quarterly report on Form 10-Q for the quarter ended March 31, 2010, Item 1A of Part II of this quarterly report and the following**:**

the ability of our customers in the U.S. Gulf of Mexico to obtain drilling permits;

oil and natural gas prices and industry expectations about future prices;

levels of oil and gas exploration and production spending;

demand and supply for offshore drilling rigs and liftboats;

our ability to enter into and the terms of future contracts;

the worldwide military and political environment, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East, West Africa and other oil and natural gas producing regions or acts of terrorism or piracy;

the impact of governmental laws and regulations, including new laws and regulations in the U.S. Gulf of Mexico arising out of the Macondo blowout incident;

the adequacy and costs of sources of credit and liquidity;

uncertainties relating to the level of activity in offshore oil and natural gas exploration, development and production;

competition and market conditions in the contract drilling and liftboat industries;

the availability of skilled personnel in view of recent reductions in our personnel;

labor relations and work stoppages, particularly in the West African and Mexican labor environments;

operating hazards such as hurricanes, severe weather and seas, fires, cratering, blowouts, war, terrorism and cancellation or unavailability of insurance coverage, or insufficient coverage;

the effect of litigation and contingencies; and our inability to achieve our plans or carry out our strategy.

Many of these factors are beyond our ability to control or predict. Any of these factors, or a combination of these factors, could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels. In addition, each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements except as required by applicable law.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are currently exposed to market risk from changes in interest rates. From time to time, we may enter into derivative financial instrument transactions to manage or reduce our market risk, but we do not enter into derivative transactions for speculative purposes. A discussion of our market risk exposure in financial instruments follows.

Interest Rate Exposure

We are subject to interest rate risk on our fixed-interest and variable-interest rate borrowings. Variable rate debt, where the interest rate fluctuates periodically, exposes us to short-term changes in market interest rates. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us to changes in market interest rates reflected in the fair value of the debt and to the risk that we may need to refinance maturing debt with new debt at a higher rate.

As of June 30, 2010, the long-term borrowings that were outstanding subject to fixed interest rate risk consisted of the 7.375% Senior Notes due April 2018, the 3.375% Convertible Senior Notes due June 2038 and the 10.5% Senior Secured Notes due October 2017 with a carrying amount of $3.5 million, $84.7 million and $292.6 million, respectively.

As of June 30, 2010, the interest rate for the $478.8 million outstanding under the term loan was 6.0%. If the interest rate averaged 1% more for 2010 than the rates as of June 30, 2010, annual interest expense would increase by approximately $4.8 million. This sensitivity analysis assumes there are no changes in our financial structure and excludes the impact of our derivatives.

The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. The following table provides the carrying value and fair value of our long-term debt instruments:

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility, due July 2013	$ 478.8	$ 421.4	$ 482.9	$ 468.4
10.5% Senior Secured Notes, due October 2017	292.6	265.9	292.3	315.8
3.375% Convertible Senior Notes, due June 2038	84.7	70.0	83.1	76.8
7.375% Senior Notes, due April 2018	3.5	2.4	3.5	3.0

Interest Rate Swaps and Derivatives

We manage our debt portfolio to achieve an overall desired position of fixed and floating rates and may employ hedge transactions such as interest rate swaps and zero cost LIBOR collars as tools to achieve that goal. The major risks from interest rate derivatives include changes in the interest rates affecting the fair value of such instruments, potential increases in interest expense due to market decreases in floating interest rates and the creditworthiness of the counterparties in such transactions. The counterparty to our zero cost LIBOR collar is a creditworthy multinational commercial bank. We believe that the risk of counterparty nonperformance is not currently material, but counterparty risk has recently increased throughout the financial system. Our interest expense was increased by $2.9 million and $6.4 million for the three and six months ended June 30, 2010, respectively and $4.0 million and $8.4 million for the three and six months ended June 30, 2009, respectively, as a result of our interest rate derivative transactions (See the information set forth under the caption Debt in Part 1, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations- *Liquidity and Capital Resources*).

In connection with the credit facility, in July 2007 we entered into a floating to fixed interest rate swap with the purpose of fixing the interest rate. The swap had decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million which was settled on April 1, 2009. We also entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010 with a ceiling of 5.75% and a floor of 4.99%.

In addition, as it relates to our term loan, in May 2008 we entered into a floating to fixed interest rate swap with the purpose of fixing the interest rate on varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million which was settled as of December 31, 2009, per the agreement.

As a result of the inclusion of a LIBOR floor in the Credit Agreement, we do not believe, as of July 27, 2009 and on an ongoing basis, that the interest rate swap and collar will be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, we prospectively discontinued cash flow hedge accounting for the interest rate swap and collar as of July 27, 2009. Because cash flow hedge accounting is not applied to these instruments for the periods after July 27, 2009, changes in fair value related to the interest rate swap and collar subsequent to July 27, 2009 are recorded in earnings. We recognized an increase in fair value of $0.1 million related to the hedge ineffectiveness of our collar as a reduction to Interest Expense in our Consolidated Statements of Operations for the three months ended June 30, 2010 and a decrease in fair value of $0.3 million related to the hedge ineffectiveness of our collar as Interest Expense in our Consolidated Statements of Operations for the six months ended June 30, 2010. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the three and six months ended June 30, 2009.

ITEM 4. CONTROLS AND PROCEDURES

We carried out an evaluation, under the supervision and with the participation of our management, including John T. Rynd, our Chief Executive Officer and President, and Stephen M. Butz, our Senior Vice President, Chief Financial Officer and Treasurer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this quarterly report. Based upon that evaluation, Mr. Rynd and Mr. Butz, acting in their capacities as our principal executive officer and our principal financial officer, concluded that, as of June 30, 2010, our disclosure controls and procedures were effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC s rules and forms, of information required to be disclosed by us in the reports that we file or submit under the Exchange Act.

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The information set forth under the caption Legal Proceedings in Note 11 of the Notes to Unaudited Consolidated Financial Statements in Item 1 of Part 1 of this report is incorporated by reference in response to this item.

ITEM 1A. RISK FACTORS

Except for the additional and updated disclosures set forth below, for additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009 and Item 1A of Part II of our quarterly report on Form 10-Q for the quarter ended March 31, 2010.

New and proposed laws and regulations arising out of the Macondo blowout incident could prevent or cause delays for our customers in obtaining drilling permits and lead to increased potential liability and costs for us and our customers, which could adversely impact our operations and profitability in the U.S. Gulf of Mexico.

On April 22, 2010, a deepwater Gulf of Mexico drilling rig, *Deepwater Horizon*, sank after an apparent blowout and fire at the Macondo wellsite. In response to this tragedy, on May 6, 2010, the Department of Interior and BOEM issued a moratorium on drilling in the United States Gulf of Mexico. This moratorium has since been lifted with respect to shallow water operations, but additional regulatory requirements have been imposed. On June 8, 2010, the BOEM issued a Notice to Lessees (NTL) outlining various new safety related regulations for offshore drilling operations. On June 18, 2010, a second NTL was issued outlining additional information that must be submitted to supplement exploration and development plans.

We have significant operations that are either ongoing or scheduled to commence in the Gulf of Mexico. The new requirements set forth in these NTL s may delay our operations and cause us to incur additional expenses in order for our rigs and operations in the Gulf of Mexico to be compliant with the new regulations. In addition, these NTL s and other potential changes in laws and regulations applicable to the offshore drilling industry in the Gulf of Mexico may continue to prevent our customers from obtaining new drilling permits in a timely manner, if at all, which could adversely impact our revenue and profitability. Our customers may also attempt to invoke the force majeure provisions in our drilling contracts, which could result in reduced dayrates during the periods of alleged force majeure or the termination of such contracts, which could further adversely impact our revenue and profitability.

In addition to recently implemented laws and regulations, the federal government is considering other new laws and regulations, including those that relate to the protection of the environment and impose additional equipment requirements, that would be applicable to the offshore drilling industry in the Gulf of Mexico. The implementation of some of the currently proposed legislation might lead to substantially increased potential liability and operating costs for us and our customers, which could cause our customers to discontinue operating in the Gulf of Mexico and redeploy capital to international markets. These actions, if taken by any of our customers, could result in underutilization of our Gulf of Mexico assets and have an adverse impact on our revenue, profitability and financial position.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth for the periods indicated certain information with respect to our purchases of our Common Stock:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Plan (2)	Maximum Number of Shares That May Yet Be Purchased Under Plan (2)
April 1-30, 2010	1,949	$ 4.13	N/A	N/A
May 1-31, 2010	594	3.29	N/A	N/A
June 1-30, 2010	1,251	2.56	N/A	N/A
Total	3,794	3.48	N/A	N/A

(1) Represents the surrender of shares of our Common Stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under our stockholder-approved long-term incentive plan.

(2) We did not have at any time during the quarter, and currently do not have, a share repurchase program in place.

ITEM 6. EXHIBITS

10.1* Executive Employment Agreement dated as of December 15, 2008, between Hercules and Stephen M. Butz.

10.2*	Amendment to Executive Employment Agreement for Lisa W. Rodriguez, dated as of May 7, 2010.
10.3*	Amendment to Executive Employment Agreement for Stephen M. Butz, dated as of May 7, 2010.
10.4*	Amendment to Executive Employment Agreement for Troy L. Carson, dated as of May 7, 2010.
31.1*	Certification of Chief Executive Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of the Chief Executive Officer and the Chief Financial Officer of Hercules pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed 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.

HERCULES OFFSHORE, INC.

By: **/s/ John T. Rynd**
John T. Rynd
Chief Executive Officer and President
(Principal Executive Officer)

By: **/s/ Stephen M. Butz**
Stephen M. Butz
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

By: **/s/ Troy L. Carson**
Troy L. Carson
Chief Accounting Officer
(Principal Accounting Officer)

Date: August 3, 2010