TODCO
Form 10-Q
May 03, 2007

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2007

Or

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

For the transition period from to

Commission File Number 1-31983

TODCO
(Exact name of registrant as specified in its charter)

Delaware	**76-0544217**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
2000 W. Sam Houston Parkway South, Suite 800 Houston, Texas	**77042-3615**
(Address of principal executive offices)	*(Zip Code)*

(713) 278-6000
(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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

As of May 1, 2007, the Registrant had 57,771,463 shares of common stock outstanding.

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PART I

Item 1. ***Financial Statements***

TODCO
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2007 (Unaudited)	December 31, 2006
	(In millions, except share data)	
ASSETS		
Cash and cash equivalents	$ 225.5	$ 169.3
Accounts receivable		
Trade	189.4	196.8
Other	38.8	32.5
Supplies	4.9	4.9
Deferred income taxes	11.0	11.0
Other current assets	12.0	12.8
Total current assets	481.6	427.3
Property and equipment	979.2	968.4
Less accumulated depreciation	538.3	517.1
Property and equipment, net	440.9	451.3
Other assets	15.7	10.6
Total assets	$ 938.2	$ 889.2
LIABILITIES AND STOCKHOLDERS EQUITY		
Trade accounts payable	$ 74.9	$ 66.1
Accrued income taxes	23.6	21.8
Accrued income taxes former parent	35.1	51.7
Other current liabilities	50.6	58.9
Total current liabilities	184.2	198.5
Long-term debt	16.3	16.4
Deferred income taxes	99.7	110.2
Other long-term liabilities	6.0	0.2
Total long-term liabilities	122.0	126.8
Commitments and contingencies		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and none outstanding		

Common stock, $0.01 par value, 500,000,000 shares authorized, 57,770,990 shares and 57,742,030 shares issued and outstanding at March 31, 2007 and December 31, 2006, respectively	0.6	0.6
Additional paid-in capital	6,411.6	6,409.0
Retained deficit	(5,780.2)	(5,845.7)
Total stockholders equity	632.0	563.9
Total liabilities and stockholders equity	$ 938.2	$ 889.2

See accompanying notes.

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TODCO
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2007	2006
	(In millions, except per share amounts)	
Operating revenues	$ 241.9	$ 183.6
Costs and expenses		
Operating and maintenance	114.7	107.3
Depreciation	22.0	22.3
General and administrative	13.3	9.7
	150.0	139.3
Operating income	91.9	44.3
Other income (expense), net		
Interest income	2.8	2.1
Interest expense	(0.7)	(0.7)
Gain on disposal of assets, net	5.5	0.9
Other, net		0.2
	7.6	2.5
Income before income taxes and cumulative effect of a change in accounting principle	99.5	46.8
Income tax expense	38.8	17.6
Income before cumulative effect of a change in accounting principle	60.7	29.2
Cumulative effect of a change in accounting principle, net of tax		0.1
Net income	$ 60.7	$ 29.3
Net income per common share:		
Basic:		
Income before cumulative effect of a change in accounting principle	$ 1.06	$ 0.48
Cumulative effect of a change in accounting principle		
Net income per common share	$ 1.06	$ 0.48
Diluted:		
Income before cumulative effect of a change in accounting principle	$ 1.05	$ 0.47

Cumulative effect of a change in accounting principle		
Net income per common share	$ 1.05	$ 0.47
Weighted average common shares outstanding:		
Basic	57.5	61.4
Diluted	57.9	62.0

See accompanying notes.

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TODCO
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2007	2006
	(In millions)	
Cash Flows from Operating Activities		
Net income	$ 60.7	$ 29.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Cumulative effect of a change in accounting principle, net of tax		(0.1)
Depreciation	22.0	22.3
Deferred income taxes	(5.7)	(7.6)
Stock-based compensation expense	1.6	1.5
Net gain on disposal of assets	(5.5)	(0.9)
Deferred income, net	(0.1)	(17.4)
Deferred expenses, net	(3.7)	4.8
Excess tax benefit from stock based compensation	(0.4)	(0.9)
Changes in operating assets and liabilities		
Accounts receivable, net	1.1	(21.2)
Accounts payable and other current liabilities	6.3	9.5
Income taxes receivable/payable, net	(12.7)	23.6
Other, net	(1.9)	(0.7)
Net cash provided by operating activities	61.7	42.2
Cash Flows from Investing Activities		
Capital expenditures	(11.9)	(5.8)
Investment in oil and gas partnership	(0.5)	
Decrease in restricted cash	1.8	
Proceeds from disposal of assets, net	5.8	1.0
Net cash used in investing activities	(4.8)	(4.8)
Cash Flows from Financing Activities		
Payments on short-term debt		(2.9)
Proceeds from short-term debt		2.4
Excess tax benefit from stock based compensation	0.4	0.9
Issuance of common stock under long-term incentive plans	(1.1)	(0.5)
Other, net		0.1
Net cash used in financing activities	(0.7)	
Net increase in cash and cash equivalents	56.2	37.4
Cash and cash equivalents at beginning of period	169.3	163.0

Cash and cash equivalents at end of period	$ 225.5	$ 200.4

See accompanying notes.

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TODCO
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 Nature of Business

TODCO (together with its subsidiaries and predecessors, unless the context requires otherwise, the Company, we or our), is a leading provider of contract oil and gas drilling services, primarily in the United States (U.S.) Gulf of Mexico shallow water and inland marine region, an area we refer to as the U.S. Gulf Coast. The Company owns 64 drilling rigs, consisting of 24 jackup rigs, 27 inland barge rigs, three submersible rigs, one platform rig and nine land rigs. The Company contracts its drilling rigs, related equipment and work crews primarily on a dayrate basis to drill oil and natural gas wells. The Company also operates a fleet of 42 inland tugs, 18 offshore tugs, 36 crew boats, 33 deck barges, 17 shale barges, four spud barges and one offshore barge through its wholly-owned subsidiary, Delta Towing LLC (Delta Towing).

In March 2007, the Company announced that it had entered into a merger agreement with Hercules Offshore, Inc., a Delaware corporation (Hercules), and THE Hercules Offshore Drilling Company LLC, a Delaware limited liability company and a direct and wholly-owned subsidiary of Hercules (Merger Sub). Under the terms of the merger agreement, which was unanimously approved by the Company s Board of Directors and the Board of Directors of Hercules, the Company will merge with and into Merger Sub, with Merger Sub as the surviving entity, which the Company refers to as the merger. Pursuant to the terms of the merger agreement, at the effective time of the merger, each share of Company common stock will be converted into the right to receive an amount of consideration, on a per-share basis, equal to $16.00 plus the product of (1) 0.979 and (2) the average closing price of Hercules common stock during a ten day consecutive trading valuation period ending on the fifth calendar day prior to the effective date of the merger, or if the fifth calendar day is not a trading day, ending on the immediately preceding trading day. The completion of the merger is subject to various conditions. Those conditions include, among other things: (1) approval by Hercules stockholders of its issuance of additional shares of Hercules common stock to be issued to the Company s stockholders in the merger, (2) approval and adoption of the merger agreement by both the Company s and Hercules stockholders, (3) termination or expiration of the applicable waiting period (and any extension thereof) under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, (4) approval of the listing of these shares of Hercules common stock to be issued in the merger on the NASDAQ Global Select Market, and (5) no more than 5% of the Company s stockholders exercising statutory appraisal or dissenters rights.

Note 2 Summary of Significant Accounting Policies and Basis of Consolidation

Basis of Consolidation These condensed financial statements have been prepared in accordance with the rules of the Securities and Exchange Commission for interim financial statements and do not include all annual disclosures required by accounting principles generally accepted in the United States. These financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company s Form 10-K for the fiscal year ended December 31, 2006. The condensed financial information as of March 31, 2007 and for the three months ended March 31, 2007 and 2006 is unaudited, but includes all adjustments that management considers necessary for a fair presentation of the Company s consolidated results of operations, financial position and cash flows. Results for the three months ended March 31, 2007 are not necessarily indicative of results to be expected for the full fiscal year 2007 or any other future periods.

The Company consolidates all majority owned subsidiaries in which the Company, either through direct or indirect ownership, has a controlling financial interest. In addition, the Company consolidates all variable interest entities where it is the primary beneficiary. All intercompany transactions and accounts have been eliminated.

Accounting Estimates The preparation of consolidated 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, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. The Company evaluates its estimates on an ongoing basis, including those related to bad debts, supplies obsolescence, investments, property and equipment and other long-lived assets, income taxes, personal injury claim liabilities, 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 such estimates.

Cash and Cash Equivalents Cash equivalents are stated at cost plus accrued interest, which approximates fair value. Cash equivalents are highly liquid investments with an original maturity of three months or less. As of March 31, 2007, and December 31, 2006, the Company had $4.5 million and $6.3 million, respectively, of restricted cash to support two performance bonds issued in connection with our contracts with Pemex Exploration and Production (PEMEX), the Mexican national oil company. This restricted cash is included in other assets on the condensed consolidated balance sheet.

Accounts Receivable and Allowance for Doubtful Accounts Accounts receivable trade are stated at the historical carrying amount net of write-offs and allowance for doubtful accounts receivable. Interest receivable on delinquent accounts receivable is included in the accounts receivable trade balance and recognized as interest income when collectibility is reasonably assured. Uncollectible accounts receivable trade are written off when a settlement is reached for an amount that is less than the outstanding historical balance. The Company establishes an allowance for doubtful accounts receivable on a case-by-case basis when it believes the collection of specific amounts owed is unlikely to occur. This allowance was $0.4 million at March 31, 2007, and $0.5 million at December 31, 2006.

Supplies Supplies are carried at the lower of average cost or market value less an allowance for obsolescence. This allowance was $0.8 million at March 31, 2007 and December 31, 2006.

New Accounting Pronouncements In February 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115* (SFAS 159). Under SFAS 159, entities may elect to measure specified financial instruments and warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. The election, called the fair value option, will enable entities to achieve an offset accounting effect for changes in fair value of certain related assets and liabilities without having to apply complex hedge accounting provisions. SFAS 159 is expected to expand the use of fair value measurement consistent with the Board s long-term objectives for financial instruments. SFAS 159 is effective as of the beginning of a company s first fiscal year that begins after November 15, 2007. The Company does not anticipate the adoption of SFAS 159 to have a material effect on its financial condition, cash flow or results of operations.

FIN 48 The Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), at the beginning of fiscal year 2007. FIN 48 prescribes a recognition threshold that a tax position is required to meet before being recognized in the financial statements and provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition issues. As a result of the implementation, the Company recognized a $4.8 million adjustment to the beginning balance of retained earnings upon the adoption of FIN 48. See Note 7 for further discussion regarding the adoption of FIN 48.

Note 3 Capital Stock

Capital Structure In February 2004, the Company amended its certificate of incorporation to, among other things, create two classes of common stock, Class A and Class B, increase its authorized capital stock and to convert any issued and outstanding shares of the Company s common stock into Class B common stock. In May 2006, the Company amended its certificate of incorporation to eliminate the Class B common stock. As amended, the Company s authorized capital stock consists of (i) 500,000,000 shares of common stock, par value $.01 per share, and (ii) 50,000,000 shares of preferred stock, par value $.01 per share.

Note 4 Delta Towing

Prior to January 1, 2006, the Company owned a 25 percent equity interest in Delta Towing, a joint venture formed to own and operate the Company s U.S. marine support vessel business, consisting primarily of shallow water tugs, crewboats and utility barges. The Company previously contributed its support vessel business to the joint venture in return for a 25 percent ownership interest and certain secured notes receivable from Delta Towing with a face value of $144.0 million. The remaining 75 percent ownership interest was held by affiliates of Edison Chouest Inc. (Chouest), which also loaned Delta Towing $3.0 million.

In January 2006, the Company purchased Chouest s 75% interest in Delta Towing for $1.1 million, including the extinguishment of Delta Towing s $2.9 million related party note to Chouest. The acquisition of the 75% interest was accounted for under the purchase method of accounting. As a result, the Company recognized a purchase price adjustment of $3.9 million, which reduced, on a pro rata basis, amounts assigned to Delta Towing s acquired assets. The purchase of the additional interest in Delta Towing did not have a material effect on the Company s consolidated results of operations, financial position or cash flows for the period ended March 31, 2006, since Delta Towing was already consolidated in the Company s consolidated financial statements in accordance with FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* (FIN 46).

Note 5 Long-Term Debt and Capital Lease Obligations

Long-term debt, net of unamortized discounts, premiums, and fair value adjustments, was comprised of the following (in millions):

	March 31, 2007	December 31, 2006
6.95% Senior Notes, due April 2008	$ 2.2	$ 2.2
7.375% Senior Notes, due April 2018	3.5	3.5
9.5% Senior Notes, due December 2008	10.6	10.7
Total	16.3	16.4
Less debt due within one year		
Total long-term debt	$ 16.3	$ 16.4

Revolving Credit Facility. In December 2005, the Company entered into a four-year, $200 million floating-rate secured revolving credit facility (the 2005 Facility). The 2005 Facility is secured by most of the Company s drilling rigs, receivables, the stock of most of its U.S. subsidiaries and is guaranteed by some of its subsidiaries. Borrowings under the 2005 Facility bear interest at the Company s option at either (1) the higher of (A) the prime rate and (B) the federal funds rate plus 0.5%, plus a margin in either case of 1.25% or (2) the London Interbank Offering Rate (LIBOR) plus a margin of 1.60%. Commitment fees on the unused portion of the 2005 Facility are 0.55% of the average daily available portion and are payable quarterly. Borrowings and letters of credit issued under the 2005 Facility may not exceed the lesser of $200 million or one third of the fair market value of the drilling rigs securing the facility, as determined from time to time by a third party approved by the agent under the facility.

Financial covenants include maintenance of the following:

- a working capital ratio of (1) current assets plus unused availability under the facility to (2) current liabilities of at least 1.2 to 1,
- a ratio of total debt to total capitalization of not more than 0.35 to 1.00,
- tangible net worth of not less than $375 million, and

in the event availability under the facility is less than $50 million, a ratio of (1) EBITDA (earnings before interest, taxes, depreciation and amortization) minus capital expenditures to (2) interest expense of not less than 2 to 1, for the previous four fiscal quarters.

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The revolving credit facility provides, among other things, for the issuance of letters of credit that the Company may utilize to guarantee performance under some drilling contracts, as well as insurance, tax and other obligations in various jurisdictions. The 2005 Facility also provides for customary fees and expense reimbursements and includes other covenants (including limitations on the incurrence of debt, mergers and other fundamental changes, asset sales and dividends) and events of default (including a change of control) that are customary for similar secured non-investment grade facilities.

During the three months ended March 31, 2007 and 2006, the Company recognized $0.3 million and $0.3 million, respectively, in interest expense related to commitment fees on the unused portion of the respective facility. During the three months ended March 31, 2007 and 2006, the Company amortized $0.1 million and $0.1 million, respectively, in deferred financing costs as a component of interest expense. On March 18, 2007, in connection with the Company s entry into the merger agreement with Hercules, the Company also entered into an amendment to the 2005 Facility to change, among other things, sections to provide that the Company s entrance into the merger agreement would not cause a default under the terms of the 2005 Facility. At March 31, 2007 and December 31, 2006, the Company had no borrowings outstanding under the 2005 Facility.

Senior Notes At March 31, 2007, the Company had Senior Notes due to third parties outstanding bearing interest at 6.95%, 7.375% and 9.5% with a principal amount of approximately $2.2 million, $3.5 million, and $10.2 million, respectively. The fair value of these notes at March 31, 2007 was approximately $2.3 million, $3.8 million, and $10.8 million, respectively, based on the most recent market valuations. The Company recognized $0.3 million in interest expense related to these notes for both of the three months ended March 31, 2007 and 2006.

Other Debt The Company entered into an unsecured line of credit with a bank in Venezuela in the third quarter of 2004 to provide a maximum of 4.5 billion Venezuela Bolivars which was increased to 6.0 billion Venezuela Bolivars in March 2006 ($2.8 million U.S. dollars at the March 31, 2007 exchange rate) in order to manage local currency liquidity. Each draw on the line of credit is denominated in Venezuela Bolivars and is evidenced by a 30-day promissory note that bears interest at the then market rate as designated by the bank. The promissory notes are pre-payable at any time at the Company s option. However, if not repaid within 30 days, the promissory notes may be renewed at mutually agreeable terms for an additional 30-day period at the then designated interest rate. There are no commitment fees payable on the unused portion of the line of credit, and the facility is reviewed annually by the bank s board of directors.

The Company had no amounts outstanding under this line of credit at March 31, 2007, or December 31, 2006. The Company incurred no interest expense related to this line of credit for the three months ended March 31, 2007. The Company recognized minimal interest expense for the three month period ended March 31, 2006 related to the Venezuela line of credit.

Other Debt Related Party In connection with the acquisition of the U.S. marine support vessel business, Delta Towing entered into a $3.0 million note agreement with Chouest dated January 30, 2001. In conjunction with the purchase of Chouest s 75% interest in Delta Towing in January 2006, the outstanding balance of $2.9 million was retired. The note had an interest of 8 percent per annum, payable quarterly. No interest expense related to this note was incurred during the three months ended March 31, 2006.

Capital Lease Obligations From time to time the Company may enter into capital lease agreements for certain drilling equipment. As of March 31, 2007, the Company has no capital lease obligations.

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Note 6 Other Current Liabilities

Other current liabilities are comprised of the following (in millions):

	March 31, 2007	December 31, 2006
Accrued self-insurance claims	$ 19.5	$ 19.9
Deferred income	4.6	10.3
Accrued payroll and employee benefits	14.0	17.9
Accrued taxes, other than income	9.1	7.7
Other	3.4	3.1
Total other current liabilities	$ 50.6	$ 58.9

Note 7 Income Taxes

Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. Deferred tax assets and liabilities are recognized for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of the Company s assets and liabilities using the applicable tax rates in effect.

In March 2007, 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 we did not remit withholding tax due on other deductions. Based on advice from local counsel, the Company believes the assessment will not be upheld and intends to contest these assessments vigorously. While the Company cannot predict or provide assurance as to the ultimate outcome, it does not believe the outcome of this assessment will have a material effect on its financial statements. Depending on the ultimate outcome of the 2004 assessment, the Company anticipates that the Mexican tax authorities could make similar assessments for other open tax years.

Tax Sharing Agreement In connection with the Company s initial public offering in February 2004 (IPO), the Company entered into a tax sharing agreement, amended in November 2006, with its former parent, Transocean Inc. (Transocean), whereby the Company must pay Transocean for substantially all pre-IPO income tax benefits utilized or deemed to have been utilized subsequent to the closing of the IPO. In addition, the Company must also pay Transocean, per the Amended and Restated Tax Sharing Agreement, 55% of the value of the tax deductions arising from the exercise of Transocean stock options by current and former employees and directors of the Company. In return, Transocean agreed to indemnify the Company against substantially all pre-IPO income tax liabilities.

Additionally, the tax sharing agreement provides that if any person other than Transocean or its subsidiaries becomes the beneficial owner of greater than 50% of the total voting power of the Company s outstanding voting stock, the Company will be deemed to have utilized all of the pre-IPO tax benefits, and the Company will be required to pay Transocean an amount for the deemed utilization of these tax benefits adjusted by a specified discount factor. This payment is required even if the Company is unable to utilize the pre-IPO tax benefits. Pursuant to the terms of the tax sharing agreement, if the Company s proposed merger with Hercules is approved, the Company will be deemed to have utilized all of the pre-IPO tax benefits and will be required to pay Transocean for such utilization. As of March 31, 2007, the Company had approximately $180 million of pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on March 31, 2007, the estimated amount that the Company would have been required to pay Transocean would have been approximately $144 million, or 80% of the pre-IPO tax benefits.

Under the tax sharing agreement with Transocean, if the utilization of a pre-IPO tax benefit defers or precludes the Company s utilization of any post-IPO tax benefit, its payment obligation with respect to the pre-IPO tax benefit generally will be deferred until the Company actually utilizes that post-IPO tax benefit. This payment deferral will not apply with respect to, and the Company will have to pay currently for the utilization of pre-IPO tax benefits to the extent of (a) up to 20% of any deferred or precluded post-IPO tax benefit arising out of the Company s payment of foreign income taxes, and (b) 100% of any deferred or precluded post-IPO tax benefit arising out of a carryback from a subsequent year. Therefore, the Company may not realize the full economic value of tax deductions, credits and other tax benefits that arise post-IPO until it has utilized all of the pre-IPO tax benefits, if ever.

The Company has utilized pre-IPO income tax benefits to offset its current federal, state and foreign income tax obligation. After accounting for payments made to Transocean, the Company had a liability to Transocean of $35.1 million and $51.7 million as of March 31, 2007 and December 31, 2006, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

FIN 48 The Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), at the beginning of fiscal year 2007. FIN 48 prescribes a recognition threshold that a tax position is required to meet before being recognized in the financial statements and provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition issues. As a result of the implementation, the Company recognized a $4.8 million adjustment to the beginning balance of retained earnings upon the adoption of FIN 48.

The Company does not currently have any unrecognized tax benefits that, if recognized, would favorably affect the effective income tax rate in any future periods. The Company is subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. Federal income tax returns for 2004 through 2005 are open with the 2004 tax return currently under examination. All tax obligations from periods prior to the IPO are indemnified by Transocean under the tax sharing agreement, except for the Trinidad and Tobago jurisdiction.

The Company s policy is to recognize interest and/or penalties related to income tax matters in operating expense. Currently, the Company has no amounts accrued for interest or penalties related to income tax matters.

Note 8 Commitments and Contingencies

Litigation On March 19 and 20, 2007, two stockholder lawsuits were filed in the District Court of Harris County, Texas, both alleging that the Company s Board of Directors breached their fiduciary duties in approving the proposed merger among the Company, Hercules and Merger Sub. The first suit, pending in the 333rd Judicial District Court of Harris County, Texas, Cause No. 2007-16397, is a purported stockholder class action suit against the Company s directors, and contains claims for breach of fiduciary duty. The second suit, pending in the 269th Judicial District Court of Harris County, Texas, Cause No. 2007-16357, is a stockholder derivative action purportedly filed on behalf of the Company against the Company s directors and Hercules, and contains claims for breach of fiduciary duties of loyalty, due care, candor, good faith and/or fair dealing; corporate waste; unlawful self dealing; and claims that the defendants conspired, aided and abetted and/or assisted one another in a common plan to breach these fiduciary duties. Both complaints allege, among other things, that the Company s directors engaged in self-dealing in approving the proposed merger with Hercules by advancing their own personal interests or those of the Company s senior management at the expense of the Company s stockholders, utilized a defective sales process not designed to maximize stockholder value, and failed to consider any value maximizing alternatives, thus causing stockholders to receive an unfair price for their shares of Company common stock. The second suit also alleges that Hercules conspired, aided and abetted or assisted in these violations. Both complaints seek, among other things, an injunction preventing the completion of the merger, rescission if the merger is consummated, imposition of a constructive trust in favor of plaintiffs upon any benefits improperly received by the defendants, attorneys fees and expenses associated with the lawsuit and any other equitable relief the court deems just and proper. The Company and its directors believe these lawsuits are without merit and plan to defend them vigorously.

In October 2001, the Company was notified by the U.S. Environmental Protection Agency (EPA) that the EPA had identified a subsidiary of the Company as a potentially responsible party 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 its designation as a potentially responsible party and does not expect that the ultimate outcome of this case will have a material adverse effect on its 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 the Company s subsidiaries and certain of Transocean s subsidiaries to

whom the Company 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. As of the date of this report, approximately 699 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 103 shared periods of employment by TODCO and Transocean 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 the Company as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named the Company as a defendant may attempt to add the Company as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. The Company continues to monitor a small group of these other cases. The Company has not determined which entity would be responsible for such claims under the Master Separation Agreement between Transocean and the Company. The Company has not yet had an opportunity to conduct any additional discovery to verify the number of plaintiffs, if any, that were employed by the Company s subsidiaries or Transocean s subsidiaries or otherwise have any connection with the Company s or Transocean s drilling operations. The Company intends to defend itself vigorously and, based on the limited information available at this time, 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.

In December 2002, the Company received an assessment for corporate income taxes from SENIAT, the national Venezuelan tax authority, of 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 2000. In March 2003, the Company paid approximately $2.6 million of the assessment, plus approximately $0.3 million in interest, and the Company is contesting the remainder of the assessment. After the Company made the partial assessment payment, the Company 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, the Company 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). The Company then initiated a judicial tax court appeal with the Venezuelan Tax Court to set aside the $8.1 million administrative tax assessment. The Company does not expect the ultimate resolution of this assessment to have a material impact on its consolidated results of operations, financial condition or cash flows. Under a master separation agreement entered into in connection with the IPO, Transocean has agreed to indemnify the Company for any losses it incurs as a result of these legal proceedings.

The Company and its subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of the Company s 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 position.

The Company cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such 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.

Surety Bonds As is customary in the contract drilling business, the Company also has various surety bonds totaling $54.1 million in place as of March 31, 2007 that secure customs obligations and certain performance and other obligations. These bonds were issued primarily in connection with the Company s contracts with Pemex Exploration and Production (PEMEX), the Mexican national oil company, and Petroleos de Venezuela

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(PDVSA), the Venezuelan national oil company. The Company s surety bonds increased from $38.8 million at December 31, 2006. This increase was principally due to the new contract obtained for *THE 205* and a bond secured in conjunction with the legal proceedings against the operator of the vessel that struck *THE 205* in December 2006.

Self-Insurance The Company is at risk for the deductible portion and self-insured portion of its insurance coverage. In the opinion of management, adequate accruals have been made based on known and estimated exposures up to the deductible portion of the Company s insurance coverage.

Insurance and Property Litigation Settlement In March 2007, we received a $7.6 million insurance settlement for damages suffered from a fire during the reactivation of *THE 256* in May 2006. The recovery of costs was recorded as a reduction to operating expenses in the first quarter of 2007.

In March 2006, the Company received a $4.0 million settlement from a third party on the Company s inland barge *Rig 62* related to a blowout and fire that occurred in June 2003. The settlement was a partial reimbursement for damages to the rig and personal injury claims paid to the Company s employees on board the rig. The settlement was recorded as a reduction to operating expense in the first quarter of 2006.

Other Commitments To insure the availability of equipment for continuing operations, the Company has placed orders for equipment with long lead times, including a $2.1 million commitment for two top-drives and $16.3 million of drill pipe for delivery in 2007.

Note 9 Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share for the three months ended March 31, 2007 and 2006:

	Three Months Ended March 31,	
	2007	2006
	(in millions, except per share amounts)	
Numerator:		
Income before income taxes and cumulative effect of a change in accounting principle	$ 60.7	$ 29.2
Cumulative effect of a change in accounting principle, net of tax		0.1
Net income	$ 60.7	$ 29.3
Denominator:		
Weighted average shares outstanding:		
Basic	57.5	61.4
Employee stock options	0.1	0.3
Restricted stock awards and other	0.3	0.3
Diluted	57.9	62.0
Earnings per common share:		
Basic:		
Earnings before cumulative effect of a change in accounting principle	$ 1.06	$ 0.48
Cumulative effect of a change in accounting principle		
Net earnings per common share	$ 1.06	$ 0.48

Diluted:				
Earnings before cumulative effect of a change in accounting principle	$	1.05	$	0.47
Cumulative effect of a change in accounting principle				
Net earnings per common share	$	1.05	$	0.47

For the three months ended March 31, 2007, there were 345,250 underlying stock options and 66,447 shares of restricted stock awards and for the three months ended March 31, 2006, there were 179,250 underlying stock options related to the Company s common stock outstanding which were not included in the computation of diluted earnings per share because the effect of including the incremental shares was anti-dilutive for the period. No adjustments to

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net income were made in calculating diluted earnings per share for the three months ended March 31, 2007 and 2006.

Note 10 Stock-Based Compensation Plan

The Company has adopted a long-term incentive plan to provide employees, non-employee directors and consultants to the Company with additional incentives and increase their personal stake in the success of the Company. The plan provides for the grant of options to purchase shares of the Company s common stock, restricted stock, deferred performance units, deferred stock units, share appreciation rights, cash awards, supplemental payments to cover tax liabilities associated with the aforementioned types of awards and performance awards.

During the first quarter of 2007, 1,228 stock options were exercised. In addition, 102,944 shares of restricted stock awarded in previous years to employees under the long-term incentive plan, vested during the first quarter of 2007.

Compensation cost that has been charged against income for the three month periods ended March 31, 2007 and 2006 was $1.6 million and $1.5 million, respectively. The Company recognizes these compensation costs net of a forfeiture rate and recognizes the compensation costs for only those shares expected to vest on a straight-line basis over the requisite service period of the award.

Note 11 Gain on Disposal of Assets

During the first quarter of 2007, the Company recorded a net gain on disposal of assets of $5.5 million. Included in the gain on disposal of assets were additional proceeds of $3.1 million received from the purchaser of *THE 151* related to the deployment of the jackup in the U.S. Gulf of Mexico for drilling activities. In addition, Delta Towing sold two support vessels for $1.3 million and realized a gain of $1.1 million from the sale of the two support vessels. The Company also recorded a net gain of $1.3 million on the sale of drill pipe and miscellaneous equipment which was sold for $1.4 million.

During the first quarter of 2006, the Company recorded a net gain on disposal of assets of $0.9 million. Included in the gain on disposal of assets was the sale of drill pipe and other miscellaneous equipment which were sold for $0.8 million. The realized gain on the sale of the drill pipe and miscellaneous equipment was $0.8 million.

Note 12 Segments, Geographical Analysis and Major Customers

The Company s operating assets consist of jackup and submersible drilling rigs and inland drilling barges located in the U.S. Gulf of Mexico, one jackup drilling rig and a land rig in Trinidad, two jackup drilling rigs and one platform rig in Mexico, one jackup drilling rig in Angola, one jackup drilling rig in Brazil, one jackup drilling rig being reactivated in Southeast Asia and land drilling units located in the United States and Venezuela. The Company also operates a fleet of 42 inland tugs, 18 offshore tugs, 36 crew boats, 33 deck barges, 17 shale barges, four spud barges and one offshore barge. The Company provides contract oil and gas drilling services and reports the results of those operations in four business segments which correspond to the principal geographic regions in which the Company operates: U.S. Gulf of Mexico Segment, U.S. Inland Barge Segment, International and Other Segment and Delta Towing Segment.

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Operating revenues, depreciation, and operating income (loss) and by reportable business segment were as follows (in millions):

Three Months Ended:	U.S. Gulf of Mexico Segment	U.S. Inland Barge Segment	International and Other Segment	Delta Towing Segment	Corporate & Other(a)	Total
March 31, 2007						
Operating revenues	$ 106.8	$ 64.1	$ 49.9	$ 21.1	$	$ 241.9
Depreciation	8.9	6.6	5.5	1.0		22.0
Operating income (loss)	66.7	20.5	6.5	10.3	(12.1)	91.9
March 31, 2006						
Operating revenues	$ 74.3	$ 49.0	$ 44.3	$ 16.0	$	$ 183.6
Depreciation	10.7	5.5	5.1	1.0		22.3
Operating income (loss)	19.6	18.3	7.5	7.3	(8.4)	44.3

(a) Represents general and administrative expenses which were not allocated to a reportable segment.

Total identifiable assets by segment were as follows (in millions):

	March 31, 2007	December 31, 2006
U.S. Gulf of Mexico Segment	$ 271.7	$ 287.3
U.S. Inland Barge Segment	196.2	194.6
International and Other Segment	168.4	164.3
Delta Towing Segment	50.4	48.6
Corporate and Other	251.5	194.4
Total assets	$ 938.2	$ 889.2

The Company provides contract oil and gas drilling services with different types of drilling equipment in several countries, as well as other marine support services in the U.S. coastal and inland water regions through the Company s subsidiary, Delta Towing. Geographic information about the Company s operations was as follows (in millions):

	Three Months Ended March 31, 2007	2006
Operating Revenues		
United States	$ 192.0	$ 139.3

Other countries	49.9	44.3
Total operating revenues	$ 241.9	$ 183.6

	March 31, 2007	December 31, 2006
Long-Lived Assets		
United States	$ 359.9	$ 368.6
Other countries	96.7	93.3
Total long-lived assets	$ 456.6	$ 461.9

A substantial portion of the Company s assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the earnings generated by such assets during the periods.

The Company s international operations are subject to certain political and other uncertainties, including risks of war and civil disturbances (or other events that disrupt markets), expropriation of equipment, repatriation of income or capital, taxation policies, and the general hazards associated with certain areas in which operations are conducted.

The Company provides drilling rigs, related equipment and work crews primarily on a dayrate basis to customers who are drilling oil and gas wells. The Company provides these services mostly to independent oil and gas companies, but it also services major international and government-controlled oil and gas companies.

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

The following discussion should be read in conjunction with our condensed consolidated financial statements and the related notes included in Item 1 of this report. Except for the historical financial information contained herein, the matters discussed below may be considered forward-looking statements. Please see Cautionary Statement About Forward-Looking Statements for a discussion of the uncertainties, risks and assumptions associated with these statements.

Overview of Our Business

We are a leading provider of contract oil and natural gas drilling services, primarily in the United States (U.S.) Gulf of Mexico shallow water and inland marine region, an area that we refer to as the U.S. Gulf Coast. We provide these services primarily to independent oil and natural gas companies, but we also service major international and government-controlled oil and natural gas companies. Our customers in the U.S. Gulf Coast typically focus on drilling for natural gas.

We provide contract oil and gas drilling and other support services and report the results of our operations in four business segments which, for our contract drilling services, correspond to the principal geographic regions in which we operate:

U.S. Gulf of Mexico Segment We currently have 18 jackup and three submersible rigs in the shallow water U.S. Gulf of Mexico which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this segment consist of independent leg cantilever type units, mat-supported cantilever type rigs and mat-supported slot type jackup rigs that can operate in water depths up to 250 feet. Our three submersible rigs are suitable to work in water depths up to 85 feet.

U.S. Inland Barge Segment Our barge rig fleet currently consists of 12 conventional and 15 posted barge rigs. These units operate in marshes, rivers, lakes and shallow bay or coastal waterways that are known as the transition zone . This area along the U.S. Gulf Coast, where jackup rigs are unable to operate, is the world s largest market for this type of equipment.

International and Other Segment Our other operations are currently conducted in Angola, Brazil, Mexico, Trinidad, the United States and Venezuela. We operate one jackup rig in Angola and one jackup rig in Brazil. In Mexico, we have two jackup rigs and a platform rig. We have one jackup rig and a land rig in Trinidad, two land rigs in the United States and six land rigs in Venezuela. An additional jackup rig is currently undergoing reactivation in Southeast Asia. We may pursue selected opportunities in other international areas from time to time.

Delta Towing Segment Delta Towing, a wholly-owned subsidiary, operates a fleet of 42 inland tugs, 18 offshore tugs, 36 crewboats, 33 deck barges, 17 shale barges, four spud barges and one offshore barge along the U.S. Gulf Coast and in the U.S. Gulf of Mexico.

Our operating revenues for our drilling segments are based on dayrates received for our drilling services and the number of operating days during the relevant periods. The level of our operating revenues depends on dayrates, which in turn are primarily a function of industry supply and demand for drilling rigs in the business segments in which we operate. Supply and demand for drilling rigs in the U.S. Gulf Coast, which is our primary operating region, has historically been volatile. During periods of high demand, our rigs typically achieve higher utilization and dayrates than during periods of low demand. Delta Towing revenues are generally contracted on a rate per day or rate per hour of service basis pursuant to short-term contracts.

Our operating and maintenance costs for our drilling segments represent all direct and indirect costs associated with the operation and maintenance of our drilling rigs. The principal elements of these costs are direct and indirect labor and benefits, freight costs, repair and maintenance, insurance, general taxes and licenses, boat and helicopter rentals, communications, tool rentals and services. Labor, repair and maintenance and insurance costs represent the most significant components of our operating and maintenance costs.

Operating and maintenance expenses may not necessarily fluctuate in proportion to changes in operating revenues because we generally seek to preserve crew continuity and maintain equipment when our rigs are idle. In general, labor costs increase primarily due to higher salary levels, rig staffing requirements and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment.

Current Conditions and Outlook

The following table shows our average rig revenue per day and utilization for the quarterly periods ended on or prior to March 31, 2007 with respect to each of our three drilling segments. Average rig revenue per day is defined as operating revenue earned per revenue earning day in the period. Utilization in the table below is defined as the total actual number of revenue earning days in the period as a percentage of the total number of calendar days in the period for all drilling rigs in our fleet.

	Three Months Ended								
	March 31, 2005	**June 30, 2005**	**September 30, 2005**	**December 31, 2005**	**March 31, 2006**	**June 30, 2006**	**September 30, 2006**	**December 31, 2006**	**March 31, 2007**
Average Rig Revenue Per Day:									
U.S. Gulf of Mexico Jackups and Submersibles	$ 44,600	$ 51,000	$ 56,700	$ 60,800	$ 78,700	$ 104,100	$ 104,100	$ 97,100	$ 90,200
U.S. Inland Barges	25,000	27,800	29,600	30,800	33,700	37,200	42,900	44,800	47,800
International and Other	28,400	33,900	31,300	37,100	45,700	43,200	42,100	44,100	47,900
Utilization:									
U.S. Gulf of Mexico Jackups and Submersibles	56%	56%	56%	51%	50%	53%	56%	65%	63%
U.S. Inland Barges	46%	51%	53%	55%	60%	61%	62%	60%	55%
International and Other	56%	55%	56%	63%	67%	71%	70%	75%	72%

Beginning in June 2006, demand in the U.S. Gulf of Mexico for jackup and submersible units began weakening, as evidenced by a decline in the dayrates we received for new drilling contracts for this segment. Consequently, the average rig revenue per day we received for U.S. Gulf of Mexico jackup and submersible rigs remained the same from the second quarter to the third quarter of 2006, but then declined 7% in the fourth quarter for the first time in thirteen quarters. This decline continued into the first quarter of 2007. Softening demand also adversely affected our ability to obtain term contracts (as opposed to well-by-well contracts) for all of our rigs operating in the U.S. Gulf of Mexico. Our backlog of total rig days under term contracts has increased from 3,893 rig days at February 20, 2007, to 5,022 rig days at April 30, 2007. This increase is primarily the result of a new three-year contract in Malaysia, a new two-year contract in Mexico and a new one-year contract in Angola. Actual total term contract days for our Gulf of Mexico jackup rigs have decreased 211 days and for our inland barges they have decreased 574 days over the same period.

We believe this weakened demand is attributable to reduced prices for natural gas in the Gulf of Mexico and to customer uncertainty regarding future prices of natural gas. These factors, we believe, strongly influence the drilling activity of our customers who are predominantly independent oil and gas companies that sometime delay or curtail their drilling activities in response to decreases in commodity prices. Although U.S. natural gas prices have generally declined since late 2005, prices nevertheless remain relatively high compared to historical levels. The rolling twelve-month average price of natural gas has increased from $2.11 in January 1994 to $6.62 in March 2007. However, the average price of natural gas for the twelve months ending March 31, 2007 has decreased to $6.62 from $9.21 for the twelve months ending March 31, 2006.

Our average revenue per day for U.S. Gulf of Mexico jackups and submersibles for the first quarter of 2007 has decreased by 7% from the fourth quarter of 2006 while our average revenue per day for our U.S. Inland Barge segment for the first quarter of 2007 improved by 7% from the fourth quarter of 2006 and our average revenue per day for our International and Other segment improved by 9% from the fourth quarter of 2006.

Our average backlog per rig for the U.S. Gulf of Mexico segment has decreased from 88 days at December 31, 2006, to 42 days at April 30, 2007. As of April 30, 2007, 11 of our 16 marketed jackup and submersible rigs in the U.S. Gulf of Mexico were operating with dayrates ranging from $70,000 to $116,200. Current spot market rates for our jackup and submersible rigs range from $60,000 to $70,000 per day.

Demand for our barge rigs has also weakened as evidenced by a decrease in the average utilization rate for our inland barge rigs in the first quarter of 2007 compared to the fourth quarter of 2006. Additionally, our average backlog per rig has decreased from 123 days at December 31, 2006, to 59 days at April 30, 2007. While our average dayrates for our inland barge rigs have experienced a slight increase in the first quarter of 2007 compared to the fourth quarter of 2006, average dayrates may decline if utilization rates remain the same or decrease. As of April 30, 2007, 14 of our 17 marketed inland barges were operating with dayrates ranging from $30,800 to $68,100.

We believe there are currently 65 jackup rigs on order with delivery dates ranging from 2007 to 2010. Most of the rigs on order are premium, cantilevered drilling units with 350 to 400 foot water depth capability. This trend of new jackup construction, principally on speculation, could result in the creation of a worldwide oversupply of jackup rigs. This could ultimately cause dayrates and utilization percentages to continue to decline. However, the worldwide jackup fleet is aging and will need to be replaced at some point. Currently, the average age worldwide is approximately 25 years old. In addition, attrition continues and was recently accelerated in 2005 when the U.S. Gulf of Mexico experienced two major hurricanes, which destroyed or significantly damaged nine jackup drilling rigs.

Greater demand for jackup rigs in international areas over the last three years has reduced the overall supply of jackups in the U.S. Gulf of Mexico. This has created a more favorable supply environment for the remaining jackups, including ours. We believe there are 88 jackup rigs remaining in the U.S. Gulf of Mexico of which three jackup rigs have announced departures for international contracts during the second and third quarters of 2007. Any additional departures could further tighten the jackup rig supply in the U.S. Gulf of Mexico.

In the past, we were awarded contracts with PEMEX for two of our jackup rigs and a platform rig. *THE 206* is currently operating under a 615-day contract at dayrates of approximately $64,000 which became effective in late October 2005. A new two-year contract will commence in late June 2007, following the completion of the current drilling contract, at a dayrate of approximately $112,500. Currently, *THE 205*, our other jackup rig in Mexico, is undergoing repairs and is anticipated to return to work for PEMEX in June 2007 under a new two-year contract. Dayrates for the new PEMEX contract will be adjusted quarterly principally based on the published U.S. Gulf of Mexico dayrates for 200-foot mat-supported cantilevered rigs plus $20,000. The contract for *Platform Rig 3* is 1,289 days in duration and began operating in December 2004 at a contract dayrate of approximately $29,000. Each of the contracts can be terminated by PEMEX on five days notice, subject to certain conditions.

In March 2007, we signed a three-year drilling contract for our jackup drilling rig, *THE 208*. This rig, a 200-foot mat-supported cantilevered jackup rig, was constructed in 1980 and has been cold-stacked in Trinidad since March 2002, since it is unable to operate in the U.S. Gulf of Mexico due to regulatory restrictions. It is anticipated that the rig will begin drilling operations through a local contractor by the end of 2007 for an independent oil and gas company to develop the Sarawak area offshore East Malaysia.

Also, in April 2007, we signed a one-year contract extension for our jackup rig, *THE 185*, in Angola with Angola Drilling Company in direct continuation when its current term contract ends in August 2007. The dayrate for the one-year extension is $125,000 per day.

Rig Reactivations

Since December 31, 2004, we have completed the reactivation of nine drilling rigs, consisting of four jackup rigs, two submersible rigs and three barge rigs. These reactivations were previously reported in our Annual Report on Form 10-K for 2006. In each case, except for *THE 153*, our rig reactivations were supported by term drilling contracts at dayrates sufficient to recover, over the term of the contract, a substantial portion of our expected operating expenses of performing the contract and the anticipated costs of reactivating the rig.

THE 208 is currently in a shipyard in Southeast Asia for an extensive shipyard reactivation. We are presently evaluating shipyard tenders and anticipate awarding a shipyard contract in the near future. In addition to the rig being reactivated, the rig is also being upgraded for international service and converted from a mechanically driven rig to a conventional powered SCR rig. The rig is in Southeast Asia to undergo an extensive shipyard reactivation and upgrade that will include conversion from a mechanically driven rig to a conventionally powered SCR rig. As of March 31, 2007, we have incurred $2.0 million related to the reactivation of the rig, including $0.6 million of

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expense and $1.4 million of capital expenditures. As of March 31, 2007 we have committed approximately $22.6 million to purchase long lead time owner furnished equipment for the rig in order to protect the project schedule required to meet the contract commitments for delivery of the rig to our customer. We estimate the total cost to reactivate *THE 208* will be approximately $55 million to $60 million.

We may reactivate or commit to reactivate additional cold stacked rigs in 2007, but only if we are able to obtain suitable term contracts on the reactivated rig or if we are confident that we will be able to do so in view of then favorable market conditions.

In the second quarter 2006, we mobilized two land rigs from Venezuela to the United States for the purpose of reactivating the rigs. As of March 31, 2007, we have incurred costs totaling $4.8 million, including $4.2 million of expense and $0.6 million of capital expenditures. We anticipate an additional $1.0 million of capital expenditures associated with the reactivations will be incurred in the second quarter of 2007. The reactivation of both rigs was substantially completed by the end of April 2007 and the rigs are currently being marketed in the United States.

Repairs and Scheduled Maintenance

In December 2006, *THE 205* was struck by a cargo vessel. The total estimated cost of repairs related to this incident is $10.0 million. As of March 31, 2007, we have recorded $0.8 million as an insurance claim receivable for the total amount of costs that we have incurred to date for repairs to *THE 205* above our insurance policy s deductible of $4.1 million. The repairs are scheduled to be completed in the second quarter of 2007 at which time the rig will commence operations under its new contract with PEMEX. We have initiated proceedings against the cargo vessel and a lawsuit has been filed against the vessel owners to recover the cost of these additional repairs which proceedings will extend into the second quarter of 2007.

THE 202 returned to service in June 2006 after sustaining damage during a jacking incident in the fourth quarter of 2005. In returning this rig to service, we incurred a total of $13.9 million in costs, of which $7.3 million was recorded as an insurance claim receivable pending under our insurance. During the first quarter of 2007, we received claim reimbursements totaling $2.2 million resulting in a claim receivable balance of $5.1 million at March 31, 2007.

In May 2006, while reactivation work was in progress, *THE 256* suffered fire damage. We made a claim under our insurance policies to recover costs exceeding our deductible. In March 2007, we recorded an insurance claim receivable settlement of $7.6 million related to this claim which reduced our insurance claim expense for the quarter. As of March 31, 2007, we have received $5.9 million of the receivable amount.

In addition to the above, *THE 150* and *THE 152* are undergoing repairs which are expected to last for a combined 54 days in the second quarter of 2007 totaling approximately $3.5 million. Additionally, *THE 200* will be out of service for approximately 25 days in the second quarter to complete work at a cost of $0.3 million which was commenced during the first quarter related to damage suffered during Hurricane Katrina in 2005. *THE 203* is expected to incur $2.0 million and be idle for 14 days while repairs are made to the jacking system and top drive. *THE 201* is expected to incur approximately $1.1 million to complete the repairs initiated in the first quarter of 2007 while the rig was in the shipyard.

Planned maintenance downtime in our Inland Barge segment for the second quarter totals 80 days and approximately $4.5 million. Included are 36 days for *Rig 28* and 27 days on *Rig 49* in order to complete hull repairs while on drydock totaling approximately $3.0 million, and approximately $1.5 million of planned maintenance expense to certain drilling equipment on *Rig 52*, *Rig 57* and *Rig 64* which will require approximately 17 days downtime.

We expect to continue our strategy of accelerating scheduled maintenance projects for selected units based on rig availability due to the market weakness as mentioned above.

During the third quarter of 2005, Hurricanes Katrina and Rita impacted our offshore and inland water operations. All of the damage caused by these two hurricanes is covered under our hull and machinery insurance policy with a total incident deductible of $1.0 million. In the first quarter of 2007, it was discovered damage had been incurred by *THE 200* during Hurricane Katrina. As a result, we recognized additional expenses of $0.2 million in the first quarter of 2007, having recorded $0.8 million in expenses through 2006, and recorded a claims receivable for all additional costs incurred of $5.4 million. As of December 31, 2006, we had incurred $6.1 million in expenses related to damages caused by Hurricane Rita. We recorded $5.1 million of claims receivable for the repair amount incurred above the $1.0 million insurance deductible related to losses sustained during Hurricane Rita. Any remaining expenses incurred related to damage caused by Hurricanes Katrina and Rita will be recorded as a claims receivable.

In October 2006, we extended our principal insurance coverages for property damage, liability and occupational injury and illness for a five month term. Generally, our deductible levels under the hull and machinery policies are 15% of individual insured asset values per occurrence except in the event of a total loss only where the deductible would be zero. An annual limit of $75.0 million and a minimum deductible of $5.0 million per occurrence apply in the event of a windstorm. In an effort to control premium costs, our insurance coverage continues to cover 70% of our losses in excess of the applicable deductible and we self insure the remaining 30% of any such losses. The primary marine package also provides coverage for cargo, control of well, seepage, pollution and property in our care, custody and control. Our deductible for this coverage varies between $250,000 and $1.0 million per occurrence depending upon the coverage line. In addition to our marine package, we have separate policies providing coverage for general domestic liability, employer s liability, domestic auto liability and non-owned aircraft liability with $1.0 million deductibles per occurrence. We also have an excess liability policy that extends our coverage to an aggregate of $200.0 million under all of these policies. Our insurance program also includes separate policies that cover certain liabilities in foreign countries where we operate.

The five-month extension did not increase our premium cost, which remained at approximately $15.0 million per annum under these policies, nor did it change our hull and machinery insured value from approximately $1.1 billion. We believe our current insurance coverage, deductibles and the level of risk involved is adequate and reasonable. However, insurance premiums and/or deductibles could be increased or coverages may be unavailable in the future.

Effective March 1, 2007, we renewed our hull and machinery insurance with essentially the same terms and conditions as our previous policy. However, we increased our insured values from $1.1 billion to $1.8 billion and decreased our deductible per occurrence from 15% of insured asset values to 10% of insured asset values except in the event of a total loss in which case the deductible is zero. The annual premium for our new hull and machinery policy is $13.3 million.

Critical Accounting Policies and Estimates

Management s Discussion and Analysis of Financial Condition and Results of Operations is based upon our Consolidated Condensed Financial Statements, which we have prepared in accordance with U.S. generally accepted accounting principles. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosure of contingent assets and liabilities. Management bases its estimates on historical experience and on various other assumptions that it believes 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. Senior management has discussed the development, selection and disclosure of these estimates with the Audit Committee of our Board of Directors. Actual results may differ from these estimates under different assumptions or conditions.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used, or if changes in the estimate that are reasonably likely to occur could materially impact the financial statements. Management believes that there have been no significant changes during the three months ended March 31, 2007 to the items that we disclosed as our critical accounting policies and estimates in Management s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

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Results of Continuing Operations

The following table sets forth our operating days, average rig utilization rates, average rig revenue per day, revenues and operating expenses by operating segment for the periods indicated:

	For The Three Months Ended March 31, 2007	2006
	(In millions, except per day data)	
U.S. Gulf of Mexico Segment:		
Operating days	1,184	944
Available days(a)	1,890	1,890
Utilization(b)	63%	50%
Average rig revenue per day(c)	$ 90,200	$ 78,700
Operating revenues	$ 106.8	$ 74.3
Operating and maintenance expenses(d)	31.2	44.0
Depreciation	8.9	10.7
Operating income	66.7	19.6
U.S. Inland Barge Segment:		
Operating days	1,342	1,454
Available days(a)	2,430	2,430
Utilization(b)	55%	60%
Average rig revenue per day(c)	$ 47,800	$ 33,700
Operating revenues	$ 64.1	$ 49.0
Operating and maintenance expenses(d)	37.0	25.2
Depreciation	6.6	5.5
Operating income	20.5	18.3
International and Other Segment:		
Operating days	1,042	970
Available days(a)	1,440	1,440
Utilization(b)	72%	67%
Average rig revenue per day(c)	$ 47,900	$ 45,700
Operating revenues	$ 49.9	$ 44.3
Operating and maintenance expenses(d)	37.9	31.7
Depreciation	5.5	5.1
Operating income	6.5	7.5
Delta Towing Segment:		
Operating revenues	$ 21.1	$ 16.0
Operating and maintenance expenses(d)	8.6	6.4
Depreciation	1.0	1.0
General and administrative expenses	1.2	1.3
Operating income	10.3	7.3
Total Company:		
Rig operating days	3,568	3,368
Rig available days(a)	5,760	5,760
Rig utilization(b)	62%	58%
Average rig revenue per day(c)	$ 61,900	$ 49,800
Operating revenues	$ 241.9	$ 183.6
Operating and maintenance expenses(d)	114.7	107.3

Depreciation	22.0	22.3
General and administrative expenses	13.3	9.7
Operating income	91.9	44.3

(a) Available days are the total number of calendar days in the period for all drilling rigs in our fleet.

(b) Utilization is the total number of revenue earning days in the period as a percentage of the total number of calendar days in the period for all drilling rigs in our fleet.

(c) Average rig revenue per day is defined as operating revenue earned per revenue earning day in the period for all drilling rigs and for Total Company excludes operating revenues related to our Delta Towing segment.

(d) Excludes depreciation, amortization and general and administrative expenses.

Three Months Ended March 31, 2007 and 2006

Operating Revenues. Total operating revenue increased $58.3 million, or 32%, during the first quarter of 2007 as compared to the same period in 2006. Overall average rig revenue per day increased from $49,800 in the first quarter of 2006 to $61,900 for the three months ended March 31, 2007. The increase in average rig revenue per day reflects the improvement of market conditions in the U. S. Gulf Coast after the first quarter of 2006, which has since showed some weakening in the last quarter of 2006 and the first quarter of 2007, along with continuing improvement in average dayrates in our inland barge market and our international and other market. Average rig utilization for our overall drilling rig fleet increased to 62% for the first quarter of 2007 from 58% in the first quarter of 2006.

Operating revenues for our U.S. Gulf of Mexico segment increased $32.5 million, or 44%, during the first quarter of 2007 as compared to the same period in 2006. In the three months ended March 31, 2007, we achieved higher average rig revenue per day for our jackup and submersible drilling fleet as compared to the first quarter of 2006, although the average dayrates have decreased, beginning in the fourth quarter of 2006, from those we obtained in the second and third quarters of 2006. Average revenue per day increased to $90,200 for the three months ended March 31, 2007, up from $78,700 for the three months ended March 31, 2006, which resulted in an additional $13.6 million in operating revenues. Results for the first quarter of 2007 also reflect an increase in utilization in this segment. This resulted principally from our reactivation of jackup and submersible rigs during 2006. The increased utilization accounted for an $18.9 million increase in operating revenues in the first quarter of 2007 as compared to the same period in 2006.

Operating revenues for our U.S. Inland Barge segment increased $15.1 million, or 31%, during the first quarter of 2007 as compared to the same period in 2006, due to higher average rig revenue per day offset by slightly lower utilization. Although the demand has shown some weakening with our utilization for the first quarter of 2007 falling in this segment for the second consecutive quarter, average dayrates have continued to improve. Average rig revenue per day increased from $33,700 for the first quarter of 2006 to $47,800 for the comparable period in 2007. This increase resulted in additional operating revenues of $18.9 million. Utilization of our inland barge fleet was 55% for the first quarter of 2007, as compared to 60% for the comparable period in 2006, which resulted in a $3.8 million decrease in operating revenues.

Operating revenues for our International and Other segment were $49.9 million for the first quarter of 2007 for an increase of $5.6 million, or 13%, over operating revenues for the first quarter of 2006. This increase reflects the commencement of operations in Venezuela of an additional land rig in August 2006 and a full three months of operations for the land rig that began operations in February 2006. This increased utilization contributed an additional $4.2 million in operating revenues while dayrate increases in Venezuela contributed an additional $1.0 million in operating revenues. *THE 156*, which was operating in Colombia in the first quarter of 2006 and contributed $9.5 million in operating revenue for the period, began operations in Brazil in late 2006 and contributed $10.5 million in operating revenue for the first quarter of 2007. Increased daily revenue for all other operations resulted in a favorable variance of $2.9 million, offset by a decrease of $3.5 million due to slightly lower utilization for this segment. This is principally due to *THE 205* in Mexico undergoing repairs before beginning work under a new contract which is expected to commence in June 2007.

The operations of Delta Towing contributed $21.1 million in operating revenues during the first quarter of 2007, an increase of $5.1 million, or 32%, as compared to the first quarter of 2006. Continuing improvement in the U.S. Gulf Coast market conditions for marine support vessels have increased demand resulting in rate and revenue increases for Delta Towing.

Operating and Maintenance Expenses. Total operating and maintenance expenses increased $7.4 million, or 7%, in the first quarter of 2007 as compared to operating expenses of $107.3 million for the comparable period in 2006.

Operating and maintenance expenses for our U.S. Gulf of Mexico segment were $12.8 million lower for the three months ended March 31, 2007 than the first quarter of 2006 primarily due to the decrease in repair and maintenance costs of $6.7 million of which the majority was incurred in reactivating four of our cold-stacked jackup and submersible rigs in the first quarter of 2006. Additionally, insurance claim expense was $10.0 million lower for the three months ended March 31, 2007 compared to the three months ended March 31, 2006, principally due to the

recording of a $7.6 million insurance settlement for damages suffered from a fire during the reactivation of *THE 256* in May 2006. These favorable variances in operating expenses were partially offset by an increase of $5.6 million in personnel costs, principally due to personnel increases related to our reactivated rigs returning to service during 2006 and pay increases.

Our U.S. Inland Barge segment had $11.8 million higher operating and maintenance expenses in the first quarter of 2007 as compared to the first quarter of 2006. The increase was principally due to higher repair and maintenance costs of $4.1 million primarily due to scheduled repairs. In addition, insurance claim expense was $4.0 million higher for the three months ended March 31, 2007, as compared to the same period ended March 31, 2006, principally the result of a property litigation settlement of $4.0 million received during the first quarter of 2006 from the contractor of our inland barge *RIG 62* operator related to a blowout and fire that occurred in June 2003. The settlement was a partial reimbursement for damages to the rig and personal injury claims paid to our employees on board the rig. Personnel costs also increased by $2.0 million in the first quarter of 2007 as compared to the same period in 2006 primarily due to the additional rigs being utilized.

Operating and maintenance expenses for our International and Other segment were $6.2 million higher for the three months ended March 31, 2007 as compared to the three months ended March 31, 2006. This increase is principally due to $4.1 million in insurance claim expense incurred on *THE 205* resulting from the rig being struck by a cargo vessel. We have initiated proceedings against the cargo vessel and a lawsuit has been filed against the vessel owners to recover the cost of these additional repairs which proceedings will extend into the second quarter of 2007. In addition, an additional land rig began operations in Venezuela in August 2006 and contributed an additional $1.3 million in operating expenses for the three months ended March 31, 2007 as compared to the three months ended March 31, 2006. Also, the two land rigs mobilized in 2006 from Venezuela to the United States for the purpose of reactivating incurred an additional $1.3 million in operating expense when comparing the first quarter of 2007 to the first quarter of 2006.

Delta Towing operating and maintenance expenses were $2.2 million higher for the three months ended March 31, 2007 when compared to the three months ended March 31, 2006, principally due to the increased utilization of marine support vessels in the Gulf of Mexico and the shallow waters of the Gulf Coast in response to increased market demand resulting in higher personnel costs and increased repairs and maintenance expenses in the first quarter of 2007 as compared to the first quarter of 2007.

General and Administrative Expenses. General and administrative expenses were $9.7 million for the first quarter of 2006 as compared to $13.3 million for the comparable period in 2007. The $3.6 million increase in general and administrative expenses was due primarily to $1.7 million in higher personnel costs and $1.9 million in costs associated with the proposed merger with Hercules.

Gain on Disposal of Assets, Net. During the first quarter of 2007, we recorded a net gain on disposal of assets of $5.5 million. Included in the gain on disposal of assets were additional proceeds of $3.1 million received from the purchaser of *THE 151* related to the deployment of the jackup in the U.S. Gulf of Mexico for drilling activities. In addition, Delta Towing sold two support vessels for $1.3 million and realized a gain of $1.1 million from the sale of the two support vessels. We also recorded a net gain of $1.3 million on the sale of drill pipe and miscellaneous equipment which was sold for $1.4 million.

During the first quarter of 2006, we recorded a net gain on disposal of assets of $0.9 million. Included in the gain on disposal of assets was the sale of drill pipe and miscellaneous equipment which was sold for $0.8 million. The realized gain on the sale of the drill pipe and miscellaneous equipment was $0.8 million.

Income Tax Expense. The income tax expense of $38.8 million for the first quarter of 2007 is principally comprised of our obligation to Transocean under the tax sharing agreement for the utilization of pre-IPO federal and state tax benefits. Our effective tax rate of 39.0% is higher than the federal tax rate principally due to state and foreign tax expense incurred. Income tax expense of $17.6 million for the first quarter of 2006 is principally comprised of our obligation to Transocean under the tax sharing agreement for the utilization of pre-IPO federal and state tax benefits. Our effective tax rate of 37.7% is higher than the federal tax rate principally due to state and foreign tax expense incurred.

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In connection with the IPO, we entered into a tax sharing agreement with Transocean whereby we must pay Transocean for substantially all pre-IPO income tax benefits utilized or deemed to have been utilized subsequent to the closing of the IPO. In addition, we must also pay Transocean, per the Amended and Restated Tax Sharing Agreement, 55% of the value of the tax deductions arising from the exercise of Transocean stock options by our current and former employees and directors. In return, Transocean agreed to indemnify us against substantially all pre-IPO income tax liabilities.

Additionally, the tax sharing agreement provides that if any person other than Transocean or its subsidiaries becomes the beneficial owner of greater than 50% of the total voting power of our outstanding voting stock, we will be deemed to have utilized all of the pre-IPO tax benefits, and will be required to pay Transocean an amount for the deemed utilization of these tax benefits adjusted by a specified discount factor. This payment is required even if we are unable to utilize the pre-IPO tax benefits. Pursuant to the terms of the tax sharing agreement, if our proposed merger with Hercules is approved, we will be deemed to have utilized all of the pre-IPO tax benefits and will be required to pay Transocean for such utilization. As of March 31, 2007, we had approximately $180 million of pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on March 31, 2007, the estimated amount that we would have been required to pay Transocean would have been approximately $144 million, or 80% of the pre-IPO tax benefits.

Under the tax sharing agreement with Transocean, if the utilization of a pre-IPO tax benefit defers or precludes our utilization of any post-IPO tax benefit, our payment obligation with respect to the pre-IPO tax benefit generally will be deferred until we actually utilize that post-IPO tax benefit. This payment deferral will not apply with respect to, and we will have to pay currently for the utilization of pre-IPO tax benefits to the extent of (a) up to 20% of any deferred or precluded post-IPO tax benefit arising out our payment of foreign income taxes, and (b) 100% of any deferred or precluded post-IPO tax benefit arising out of a carryback from a subsequent year. Therefore, we may not realize the full economic value of tax deductions, credits and other tax benefits that arise post-IPO until we have utilized all of the pre-IPO tax benefits, if ever.

We have utilized pre-IPO income tax benefits to offset our current federal, state and foreign income tax obligation. After accounting for payments made to Transocean, the Company had a liability to Transocean of $35.1 million and $51.7 million as of March 31, 2007 and December 31, 2006, respectively, for pre-IPO federal, state and foreign income tax benefits utilized.

In March 2007, we received an assessment from the Mexican tax authorities related to our operations for the 2004 tax year. This assessment contests our right to certain deductions and also claims we did not remit withholding tax due to other deductions. Based on advice from local counsel, we believe the assessment will not be upheld and intend to contest these assessments vigorously. While we cannot predict or provide assurance as to the ultimate outcome, we do not believe the outcome of this assessment will have a material effect on our financial statements. Depending on the ultimate outcome of the 2004 assessment, we anticipate that the Mexican tax authorities could make similar assessments for other open tax years.

FIN 48 We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), at the beginning of fiscal year 2007. FIN 48 prescribes a recognition threshold that a tax position is required to meet before being recognized in the financial statements and provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition issues. As a result of the implementation, we recognized a $4.8 million adjustment to the beginning balance of retained earnings upon adoption of FIN 48.

We do not currently have any unrecognized tax benefits that, if recognized, would favorably affect the effective income tax rate in any future periods. We and our subsidiaries are subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. Federal income tax returns for 2004 through 2006 are currently open with the 2004 tax return under examination. All tax obligations from periods prior to the IPO are indemnified by Transocean under the tax sharing agreement, except for the Trinidad and Tobago jurisdiction.

Our policy is to recognize interest and/or penalties related to income tax matters in operating expense. Currently, we have no amounts accrued for interest or penalties related to income tax matters.

Financial Condition

At March 31, 2007 and December 31, 2006, we had total assets of $938.2 million and $889.2 million, respectively. The $49.0 million increase in assets during the first three months of 2007 is primarily attributable to the $56.2 million increase in cash generated primarily by our operations.

Liquidity and Capital Resources

Sources and Use of Cash

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006. Net cash provided by operating activities for the three months ended March 31, 2007 and 2006 was $61.7 million and $42.2 million, respectively. The $19.5 million increase in net cash provided by operating activities is primarily attributable to an increase in net income of $31.4 million. Adjustments to reconcile net income to net cash provided by operating activities were higher in 2007, primarily due to an increase in deferred income of $17.3 million partially offset by a decrease in deferred expenses of $8.5 million for the three months ended March 31, 2007 as compared to the same period in 2006. Our net income was favorably affected by the stronger demand and higher average dayrates in the three months ended March 31, 2007 compared to the three months ended March 31, 2006 for shallow water drilling services which resulted in our average dayrates increasing from $49,800 to $61,900 and our rig utilization percentages increasing from 58% to 62%.

Changes in operating assets and liabilities resulted in a $7.2 million decrease in cash for the three month period ended March 31, 2007, compared to a $11.2 million increase in the same period in 2006. This $18.4 million decrease is primarily the result of a decrease in our income tax balances in the first three months of 2007 reflecting payments made during this period. In contrast, we experienced an increase in our taxes payable during the first three months of 2006, which contributed a favorable effect on cash flow, which was offset by an increase in our accounts receivable, reflecting the higher revenues received over the previous quarter. As average dayrates have decreased in the Gulf of Mexico segment beginning in the fourth quarter of 2006 and continuing into the first quarter of 2007, we have seen less growth in our receivables.

Net cash used in investing activities was $4.8 million for the three months ended March 31, 2007, compared to $4.8 million used in investing activities for the same period in 2006. The use of cash in investing activities for the first quarter of 2007 was primarily to fund capital expenditures of $11.9 million which was partially offset by the receipt of $5.8 million in proceeds from the sale of assets. Capital expenditures for the first quarter of 2006 were $5.8 million with proceeds from disposal of assets resulting in a cash inflow of $1.0 million.

Net cash used in financing activities was $0.7 million for the three month period ended March 31, 2007, as compared to $0.0 million for the same period in 2006. The increase in cash used in financing activities was primarily the result of lower realized excess tax benefit from stock based compensation and an increase in the cash required to issue common stock under our long-term incentive plans.

Sources of Liquidity and Capital Expenditures

Our existing cash balances and cash flows from operating activities were our primary sources of liquidity for the three months ended March 31, 2007 and 2006. For the three months ended March 31, 2007, our primary uses of cash were operating costs and capital expenditures of $11.9 million. For the three months ended March 31, 2006, our primary uses of cash were operating costs and capital expenditures of $5.8 million. At March 31, 2007, we had $225.5 million in cash and cash equivalents.

We anticipate that we will rely primarily on internally generated cash flows to maintain liquidity. From time to time, we may also make use of our revolving line of credit for cash liquidity. In December 2005, we entered into a four-year, $200 million floating-rate secured revolving credit facility (the 2005 Facility). The 2005 Facility is secured by most of our drilling rigs, receivables, the stock of most of its U.S. subsidiaries and is guaranteed by some of its subsidiaries. Borrowings under the 2005 Facility bear interest at our option at either (1) the higher of (A) the prime rate and (B) the federal funds rate plus 0.5%, plus a margin in either case of 1.25% or (2) the London Interbank Offering Rate (LIBOR) plus a margin of 1.60%. Commitment fees on the unused portion of the 2005

Facility are 0.55% of the average daily available portion and are payable quarterly. Borrowings and letters of credit issued under the 2005 Facility may not exceed the lesser of $200 million or one third of the fair market value of the drilling rigs securing the facility, as determined from time to time by a third party approved by the agent under the facility.

Financial covenants include maintenance of the following:

- a working capital ratio of (1) current assets plus unused availability under the facility to (2) current liabilities of at least 1.2 to 1,

- a ratio of total debt to total capitalization of not more than 0.35 to 1.00,

- tangible net worth of not less than $375 million, and

- in the event availability under the facility is less than $50 million, a ratio of (1) EBITDA (earnings before interest, taxes, depreciation and amortization) minus capital expenditures to (2) interest expense of not less than 2 to 1, for the previous four fiscal quarters.

The revolving credit facility provides, among other things, for the issuance of letters of credit that we may utilize to guarantee its performance under some drilling contracts, as well as insurance, tax and other obligations in various jurisdictions. The 2005 Facility also provides for customary fees and expense reimbursements and includes other covenants (including limitations on the incurrence of debt, mergers and other fundamental changes, asset sales and dividends) and events of default (including a change of control) that are customary for similar secured non-investment grade facilities. On March 18, 2007, in connection with our entry into the merger agreement with Hercules, we also entered into an amendment to the 2005 Facility to change, among other things, sections to provide that the entry into the merger agreement would not cause a default under the terms of the 2005 Facility.

At March 31, 2007, and December 31, 2006, we had no borrowings outstanding under our credit facility.

We entered into an unsecured line of credit with a bank in Venezuela in the third quarter of 2004 to provide a maximum of 4.5 billion Venezuela Bolivars which was subsequently increased to 6.0 billion Venezuela Bolivars in March 2006 ($2.8 million U.S. dollars at the current exchange rate at March 31, 2007) in order to manage local currency liquidity. Each draw on the line of credit is denominated in Venezuela Bolivars and is evidenced by a 30-day promissory note that bears interest at the then market rate as designated by the bank. The promissory notes are pre-payable at any time at the Company s option. However, if not repaid within 30 days, the promissory notes may be renewed at mutually agreeable terms for an additional 30-day period at the then designated interest rate. There are no commitment fees payable on the unused portion of the line of credit, and the facility is reviewed annually by the bank s board of directors.

At March 31, 2007, and December 31, 2006, there were no borrowings outstanding under the line of credit. There was no interest expense for the three months ended March 31, 2007, and minimal expense recognized for the three months ended March 31, 2006.

We expect capital expenditures, primarily for rig refurbishments and the purchase of capital equipment, to be approximately $62 million for the remainder of 2007, including approximately $25 million for rig reactivations. The timing and amounts we actually spend in connection with our plans to upgrade and refurbish other selected rigs is subject to our discretion and will depend on our view of market conditions and our cash flows. We would expect capital expenditures to increase as market conditions improve. From time to time we may review possible acquisitions of drilling rigs or businesses, joint ventures, mergers or other business combinations and may in the future make significant capital commitments for such purposes. Any such transactions could involve the issuance of a substantial number of additional shares or other securities or the payment by us of a substantial amount of cash. We would likely fund the cash portion, if any, of such transactions through cash balances on hand, the incurrence of additional debt, sales of assets, shares or other securities or a combination thereof. In addition, from time to time we may consider dispositions of drilling rigs. Our ability to fund capital expenditures would be adversely affected if conditions deteriorate in our business, we experience poor results in our operations or we fail to meet covenants under the revolving credit facility described above.

To insure the availability of equipment for continuing operations, we have placed orders for equipment with long lead times, including a $2.1 million commitment for two top-drives and $16.3 million of drill pipe for delivery in 2007. In addition, we have committed approximately $22.6 million to purchase long lead time owner furnished equipment for *THE 208* reactivation in order to protect the project schedule required to meet the contract commitments for delivery of the rig to our customer.

We may reactivate or commit to reactivate additional cold stacked rigs in 2007, but only if we are able to obtain suitable term contracts on the reactivated rig or if we are confident that we will be able to do so in view of then favorable market conditions.

We anticipate that our available funds, together with our cash generated from operations and amounts that we may borrow, will be sufficient to fund our required capital expenditures, working capital and debt service requirements for the foreseeable future. Future cash flows and the availability of outside funding sources, however, are subject to a number of uncertainties, especially the condition of the oil and natural gas industry. Accordingly, these resources may not be available or sufficient to fund our cash requirements.

During the three months ended March 31, 2007, there were no material changes to the contractual obligations, including our scheduled debt maturities, reported in our Annual Report on Form 10-K as of December 31, 2006. Our surety bonds, obtained primarily to secure customs obligations and certain performance and other obligations, increased from $38.8 million at December 31, 2006, to $54.1 million at March 31, 2007. This increase was principally due to the new contract obtained for *THE 205* and a bond secured in conjunction with our legal proceedings against the operator of the vessel that struck *THE 205* in December 2006.

Investment in oil and gas partnerships

We have invested $1.7 million in an oil and gas exploration and production limited partnership operating in the inland waterway of the U.S. Gulf Coast and Offshore U.S. Gulf of Mexico. Our investment in this oil and gas partnership was the result of a customer relationship and is not indicative of a strategy change, nor do we believe that the investment will be long-term in nature.

Our total investment in the partnership is classified in Other Assets on the Condensed Consolidated Balance Sheets at March 31, 2007 and December 31, 2006. Currently, the partnership has one producing well. Additional contributions to the partnership are limited to the initial commitment with provisions for optional assessments.

Merger with Hercules Offshore

In March 2007, we announced that we had entered into a merger agreement with Hercules Offshore, Inc., a Delaware corporation (Hercules), and THE Hercules Offshore Drilling Company LLC, a Delaware limited liability company and a direct and wholly-owned subsidiary of Hercules (Merger Sub). Under the terms of the merger agreement, which was unanimously approved by our Board of Directors and the Board of Directors of Hercules, we will merge with and into Merger Sub, with Merger Sub as the surviving entity, which we refer to as the merger. Pursuant to the terms of the merger agreement, at the effective time of the merger, each share of our common stock will be converted into the right to receive an amount of consideration, on a per-share basis, equal to $16.00 plus the product of (1) 0.979 and (2) the average closing price of Hercules common stock during a ten-day consecutive trading valuation period ending on the fifth calendar day prior to the effective date of the merger, or if the fifth calendar day is not a trading day, ending on the immediately preceding trading day. The completion of the merger is subject to various conditions. Those conditions include, among other things: (1) approval by Hercules stockholders of its issuance of additional shares of Hercules common stock to be issued to our stockholders in the merger, (2) approval and adoption of the merger agreement by both our and Hercules stockholders, (3) termination or expiration of the applicable waiting period (and any extension thereof) under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, (4) approval of the listing of these shares of Hercules common stock to be issued in the merger on the NASDAQ Global Select Market, and (5) no more than 5% of our stockholders exercising statutory appraisal or dissenters rights.

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Cautionary Statement About Forward Looking Statements

This report contains both historical and forward-looking statements. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include information concerning our possible or assumed future financial performance and results of operations, including statements about the following subjects:

our strategy,

improvement in the fundamentals of the oil and gas industry,

the supply and demand imbalance in the oil and gas industry,

the correlation between demand for our rigs, our earnings and our customers expectations of energy prices,

our plans, expectations and any effects of focusing on agreements and marine assets and drilling for natural gas along the U.S. Gulf Coast, pursuing efficient, low-cost operations and a disciplined approach to capital spending, maintaining high operating standards and maintaining a conservative capital structure,

estimated tax benefits and estimated payments under our tax sharing agreement with Transocean,

expected capital expenditures,

expected general and administrative expense,

refurbishment and reactivation costs,

our ability to take advantage of opportunities for growth and our ability to respond effectively to market downturns,

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

deep gas drilling opportunities,

operating standards,

payment of dividends,

competition for drilling contracts,

matters related to our letters of credit and surety bonds,

future transactions with unaffiliated third parties, including the possible sale of our Venezuelan assets,

matters relating to our future transactions, agreements and relationship with Transocean,

payments under agreements with Transocean,

liabilities under laws and regulations protecting the environment,

results and effects of legal proceedings,

- results and effects of tax assessments,
- outcome of the merger,
- future utilization rates,
- future dayrates, and
- expectations regarding improvements or changes in offshore activity, demand for our drilling rigs, our plan to operate primarily in the U.S. Gulf Coast, operating revenues, operating and maintenance expense, insurance expense and deductibles, interest expense, debt levels and other matters with regard to our outlook.

Forward-looking statements in this Form 10-Q are identifiable by use of the following words and other similar expressions:

- anticipate,
- believe,
- budget,
- could,
- estimate,
- expect,
- forecast,

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- intent,
- may,
- might,
- plan,
- potential,
- predict,
- project, and
- should.

The following factors could affect our future results of operations and could cause those results to differ materially from those expressed in the forward-looking statements included in this Form 10-Q:

- worldwide demand for oil and gas,
- exploration success by producers,
- demand for offshore and inland water rigs,
- our ability to enter into and the terms of future contracts,
- labor relations,
- political and other uncertainties inherent in non-U.S. operations (including exchange controls and currency fluctuations),
- the impact of governmental laws and regulations,
- the adequacy of sources of liquidity,
- uncertainties relating to the level of activity in offshore oil and gas exploration and development,
- oil and natural gas prices (including U.S. natural gas prices),
- competition and market conditions in the contract drilling industry,
- work stoppages,
- increases in operating expenses,
- extended delivery times for material and equipment,
- the availability of qualified personnel,
- operating hazards,

war, terrorism and cancellation or unavailability of insurance coverage,

compliance with or breach of environmental laws,

the effect of litigation and contingencies,

our inability to achieve our plans or carry out our strategy,

the matters discussed in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, and this Form 10-Q and

other factors discussed in this Form 10-Q.

Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those indicated. Stockholders should not place undue reliance on forward-looking statements. 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.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

We have exposure to foreign exchange and interest rate risk. There have been no material changes in market risk exposures from those disclosed in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

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Item 4. ***Controls and Procedures***

As of March 31, 2007, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15 of the Securities Exchange Act of 1934, as amended (the Exchange Act). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective. Disclosure controls and procedures are controls and procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II

Item 1. ***Legal Proceedings***

The Company has certain actions or claims pending that have been previously discussed and reported in the Company s Annual Report on Form 10-K for the year ended December 31, 2006. Updates to this information and new items are incorporated by reference to Note 8 contained in the Notes to Condensed Financial Statements.

Item 1A. ***Risk Factors***

Reference is made to the factors set forth under the caption Cautionary Statement About Forward-Looking Statements in Part I, Item 2 of this Form 10-Q and other risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2006, which are incorporated herein by reference. There have not been any material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006, other than as set forth below.

Any delay in completing the merger and integrating the businesses may substantially reduce the benefits expected to be obtained from the merger.

In addition to obtaining the required regulatory clearances and approvals, the merger is subject to a number of other conditions beyond the control of the Company and Hercules that may prevent, delay or otherwise materially adversely affect its completion. We cannot predict whether or when the conditions to closing will be satisfied. Any delay in completing the merger and integrating the businesses may diminish the benefits that we expect to achieve in the merger.

Failure to complete the merger could negatively impact the stock price and the future business and financial results of the Company.

We cannot assure you that the merger agreement will be approved by the Company s stockholders, the issuance of the shares of Hercules common stock will be approved by Hercules stockholders or that the other conditions to the completion of the merger will be satisfied. In addition, both the Company and Hercules have the right to terminate the merger agreement and pursue alternative transactions under certain conditions. If the merger is not completed, we will not receive any expected benefits of the merger and will be subject to risks and/or liabilities, including the following:

- failure to complete the merger might be followed by a decline in the market price of the Company s common stock,

- we may be required to pay Hercules a termination fee of $70 million if the merger agreement is terminated under specified circumstances,

- some costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by the Company whether or not the merger is completed, and

- the proposed merger may disrupt the Company s business and distract our management and employees from day-to-day operations, because work related to the merger (including integration planning) requires substantial time and resources, which could otherwise have been devoted to other business opportunities for the benefit of the Company.

If the merger is not completed, these risks and liabilities may materially adversely affect the Company s business, financial results, financial condition and stock price.

In addition, there can be no assurance that Hercules will be successful in obtaining expected financing. Although financing is not a condition to closing of the merger, if Hercules were not able to obtain the expected financing, or not able to obtain the financing on commercially reasonable terms, it might not be able to complete the merger and might be subject to other adverse consequences.

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

Issuer Purchases of Equity Securities

Period	**(a)** Total Number of Shares Purchased (1)		**(b)** Average Price Paid per Share (2)	**(c)** Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	**(d)** Maximum Number (or Approximate Dollar Value) of Shares (or Unites) that May Yet Be Purchased Under the Plans or Programs
January 2007		$			$
February 2007	21,331		33.68	NA	NA
March 2007	10,150		34.63	NA	NA
Total	31,481	$	33.99	NA	NA

(1) Represents number of common stock shares surrendered to offset tax withholding obligations in connection with the vesting of restricted stock issued to employees under our stockholder approved long-term incentive plans.

(2) Based upon the average price of our common stock on the New York Stock Exchange on the date of

surrender.

Item 6. ***Exhibits***

Exhibit Index

Exhibit No.	**Description**	**Filed Herewith or Incorporated by Reference from:**
2.1	Amended and Restated Agreement and Plan of Merger, effective as of March 18, 2007, by and among Hercules Offshore, Inc., THE Hercules Offshore Drilling Company LLC and TODCO	Exhibit 2.1 to Current Report on Form 8-K filed on March 22, 2007
3.1	Fourth Amended and Restated Certificate of Incorporation.	Exhibit 3.1 to Current Report on Form 8-K filed on May 11, 2006
3.2	Amended and Restated By-Laws	Current report on Form 8-K filed April 5, 2007.
3.3	Form of Certificate of Designation of Series A Junior Participating Preferred Stock (included as Exhibit A to Exhibit 3.3)	Included as Exhibit A to Exhibit 3.3 to Amendment 1 of Form S-1, Registration No. 333-101921, filed February 12, 2003
4.1	Amendment No. 1 to Rights Agreement, dated March 18, 2007 between TODCO and Bank of New York.	Exhibit 4.1 to Current Report on Form 8-K filed on March 22, 2007

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Exhibit No.	Description	Filed Herewith or Incorporated by Reference from:
*10.1	Form of Employee Deferred Performance Unit Award Letter under the TODCO 2005 Long Term Incentive Plan (for awards granted on or after February 26, 2007)	Exhibit 10.21 to Current Report on Form 10-K filed March 1, 2007
*10.2	TODCO Severance Policy	Exhibit 10.12 to Current Report on Form 10-K filed March 1, 2007
*10.3	Form of Employee Non-Qualified Stock Option Award Letter under the TODCO 2005 Long-Term Incentive Plan (for awards granted on or after February 26, 2007)	Exhibit 10.19 to Current Report on Form 10-K filed March 1, 2007
10.4	Amendment No. 1 to Credit Agreement among TODCO, Various Lenders and Nordea Bank Finland PLC, New York Branch, as Administrative Agent and Collateral Agent dated March 18, 2007	Exhibit 99.1 to Current Report on Form 8-K filed March 22, 2007
31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer	Filed herewith
31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer	Filed herewith
32	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer	Furnished herewith

* Management compensation contract, plan or arrangement.

Furnished, not filed, in accordance with Item 601(b)(32) of Regulation S-K.

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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.

TODCO

/s/ Dale Wilhelm

Dale Wilhelm
Vice President and Chief Financial Officer
(on behalf of TODCO and as Principal Financial Officer)

Date: May 3, 2007

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