TODCO
Form 10-Q
May 04, 2006

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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, 2006

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 registrant s 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, 2006, 61,832,851 shares of Class A common stock were outstanding.

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PART I

Item 1. ***Financial Statements***

TODCO AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2006 (Unaudited)	December 31, 2005
	(In millions, except share data)	
ASSETS		
Cash and cash equivalents	$ 200.4	$ 163.0
Accounts receivable		
Trade	119.5	107.4
Related party	9.9	9.9
Other	18.9	9.8
Supplies	4.6	4.9
Deferred income taxes	8.4	8.4
Other current assets	4.6	4.3
Total current assets	366.3	307.7
Property and equipment	923.1	919.7
Less accumulated depreciation	458.6	436.7
Property and equipment, net	464.5	483.0
Other assets	30.0	34.3
Total assets	$ 860.8	$ 825.0
LIABILITIES AND STOCKHOLDERS EQUITY		
Trade accounts payable	$ 52.4	$ 42.4
Accrued income taxes	12.2	10.9
Accrued income taxes related party	66.2	44.9
Debt due within one year	1.0	0.4
Debt due within one year related party		2.9
Interest payable related party		0.1
Other current liabilities	46.1	63.0
Total current liabilities	177.9	164.6
Long-term debt	16.6	16.6
Deferred income taxes	137.3	144.8

Other long-term liabilities	2.5	3.5
Total long-term liabilities	156.4	164.9
Commitments and contingencies		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and no shares issued and outstanding		
Common stock, Class A, $0.01 par value, 500,000,000 shares authorized, 61,663,462 shares and 61,521,990 shares issued and outstanding at March 31, 2006 and December 31, 2005, respectively	0.6	0.6
Common stock, Class B, $0.01 par value, 260,000,000 shares authorized and no shares issued and outstanding		
Additional paid-in capital	6,525.9	6,527.2
Retained deficit	(6,000.0)	(6,029.3)
Unearned compensation		(3.0)
Total stockholders equity	526.5	495.5
Total liabilities and stockholders equity	$ 860.8	$ 825.0

See accompanying notes.

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TODCO AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(In millions, except per share amounts)	
Operating revenues	$ 183.6	$ 111.9
Costs and expenses		
Operating and maintenance	107.3	68.9
Depreciation	22.3	24.0
General and administrative	9.7	8.4
Gain on disposal of assets, net	(0.9)	(1.1)
	138.4	100.2
Operating income	45.2	11.7
Other income (expense), net		
Interest income	2.1	0.5
Interest expense	(0.7)	(1.0)
Interest expense related party		(0.1)
Other, net	0.2	0.5
	1.6	(0.1)
Income before income taxes and cumulative effect of change in accounting principle	46.8	11.6
Income tax expense	17.6	3.5
Income before cumulative effect of change in accounting principle	29.2	8.1
Cumulative effect of change in accounting principle, net of tax	0.1	
Net income	$ 29.3	$ 8.1
Net income per common share:		
Basic:		
Income before cumulative effect of change in accounting principle	$ 0.48	$ 0.13
Cumulative effect of change in accounting principle		
Net income per common share	$ 0.48	$ 0.13

Diluted:		
Income before cumulative effect of change in accounting principle	$ 0.47	$ 0.13
Cumulative effect of change in accounting principle		
Net income per common share	$ 0.47	$ 0.13
Weighted average common shares outstanding:		
Basic	61.4	60.0
Diluted	62.0	60.9

See accompanying notes.

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TODCO AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(In millions)	
Cash Flows from Operating Activities		
Net income	$ 29.3	$ 8.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Cumulative effect of change in accounting principle, net of tax	(0.1)	
Depreciation	22.3	24.0
Deferred income taxes	(7.6)	(8.7)
Stock-based compensation expense	1.5	1.8
Net gain on disposal of assets	(0.9)	(1.1)
Amortization of debt issue costs		0.2
Deferred income, net	(17.4)	(9.0)
Deferred expenses, net	4.8	1.9
Excess tax benefit from stock based compensation	(0.9)	
Changes in operating assets and liabilities, net of effect of distributions to related parties		
Accounts receivable, net	(21.2)	(12.5)
Accounts payable and other current liabilities	9.5	(4.9)
Accounts receivable/payable to related party, net		1.6
Income taxes receivable/payable, net	23.6	5.7
Other, net	(0.7)	1.6
Net cash provided by operating activities	42.2	8.7
Cash Flows from Investing Activities		
Capital expenditures	(5.8)	(2.7)
Proceeds from disposal of assets, net	1.0	2.6
Net cash used in investing activities	(4.8)	(0.1)
Cash Flows from Financing Activities		
Payments on short-term debt	(2.9)	
Proceeds from short-term debt	2.4	1.3
Excess tax benefit from stock based compensation	0.9	
Issuance of common stock under long-term incentive plans	(0.5)	2.2
Other, net	0.1	0.3
Net cash provided by financing activities		3.8
Net increase in cash and cash equivalents	37.4	12.4

Cash and cash equivalents at beginning of period	163.0	65.1
Cash and cash equivalents at end of period	$ 200.4	$ 77.5

See accompanying notes.

TODCO AND SUBSIDIARIES
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 referred 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 49 inland tugs, 22 offshore tugs, 36 crew boats, 33 deck barges, 17 shale barges, five spud barges and two offshore barges.

In January 2001, the Company was acquired by Transocean Inc. (the Transocean Merger). In July 2002, Transocean Inc. (Transocean) announced plans to divest its Gulf of Mexico shallow and inland water (Shallow Water) business through an initial public offering of the Company. During 2003, the Company completed the transfer to Transocean of all revenue producing assets not related to its Shallow Water business (Transocean Assets). In February 2004, the Company completed its initial public offering and secondary stock offerings were completed in September 2004, December 2004 and May 2005. As of June 30, 2005, Transocean had sold all of its remaining shares of the Company s common stock. See Note 3.

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, 2005. The condensed financial information as of March 31, 2006 and for the three months ended March 31, 2006 and 2005 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, 2006 are not necessarily indicative of results to be expected for the full fiscal year 2006 or any other future periods.

Intercompany transactions and accounts have been eliminated. For investments in joint ventures that either do not meet the criteria of being a variable interest entity or where the Company is not deemed to be the primary beneficiary for accounting purposes, the equity method of accounting is used where the Company s ownership in the joint venture is between 20 percent and 50 percent and for investments in joint ventures where more than 50 percent is owned and the Company does not have control of the joint venture. The cost method of accounting is used for investments in joint ventures where the Company s ownership is less than 20 percent and the Company does not have significant influence over the joint venture. For investments in joint ventures that meet the criteria of a variable interest entity and where the Company is deemed to be the primary beneficiary for accounting purposes, such entities are consolidated. See Note 4.

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, 2006, and December 31, 2005, the Company had $12.1 million and $12.2 million, respectively, of restricted cash to support four performance bonds issued in connection with our contracts with PEMEX in Mexico. 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, 2006, and December 31, 2005.

Supplies Supplies are carried at the lower of average cost or market value less an allowance for obsolescence. This allowance was $0.3 million at March 31, 2006 and December 31, 2005.

Stock-Based Compensation Effective January 1, 2003, the Company adopted the fair value method of accounting for stock-based compensation using the prospective method of transition under Statement of Financial Accounting Standards (SFAS) 123, *Accounting for Stock-based Compensation* (SFAS 123). Under the prospective method and in accordance with the provisions of SFAS 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (SFAS 148), the recognition provisions are applied to all employee awards granted, modified or settled after January 1, 2003. Effective January 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R), using the modified prospective transition method and therefore has not restated results for prior periods. Under this transition method, stock-based compensation expense for the first quarter of fiscal 2006 includes compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provision of SFAS 123. Stock-based compensation expense for all stock-based compensation awards granted after January 1, 2006 is based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R. As a result of the Company having adopted SFAS 123 in an earlier period, the adoption of SFAS 123R in the first quarter of 2006 had an immaterial income effect. Under the fair value recognition provisions of SFAS 123R, the Company recognizes stock-based compensation net of an estimated forfeiture rate and only recognizes compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award, which is generally a vesting term of three years. In March 2005, the Securities and Exchange Commission (the SEC) issued Staff Accounting Bulletin No. 107 (SAB 107) regarding the SEC s interpretation of SFAS 123R and the valuation of share-based payments for public companies. The Company has applied the provisions of SAB 107 in its adoption of SFAS 123R. See Note 11 to the Consolidated Condensed Financial Statements for a further discussion on stock-based compensation.

Prior to the adoption of SFAS 123R, the Company presented all tax benefits of deductions resulting from share-based payments as operating cash flows in the cash flow statement. SFAS 123R requires the cash flows resulting from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those share-based payments (excess tax benefits) to be classified as financing cash flows. The $0.9 million excess tax benefits classified as a financing cash inflow would have been classified as an operating cash inflow if the Company had not adopted SFAS 123R.

New Accounting Pronouncements In March 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 156, *Accounting for Servicing of Financial Assets an amendment of FASB Statement No. 140* (SFAS 156). SFAS 156 amends FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* with respect to the accounting for separately recognized servicing assets and servicing liabilities. This statement is effective as of the beginning of the first fiscal year that begins after September 15, 2006. The Company does not anticipate the adoption of SFAS 156 to have a material effect on its financial condition, cash flow or results of operations.

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In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140* (SFAS 155). SFAS 155 allows financial instruments that have embedded derivatives to be accounted for as a whole (eliminating the need to bifurcate the derivative from its host) if the holder elects to account for the whole instrument on a fair value basis. This statement is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. The Company does not anticipate the adoption of SFAS 155 to have a material effect on its financial condition, cash flow or results of operations.

Note 3 Capital Stock and Related Transactions

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. As amended, the Company s authorized capital stock consists of (i) 500,000,000 shares of Class A common stock, par value $.01 per share, and 260,000,000 shares of Class B common stock, par value $.01 per share, and (ii) 50,000,000 shares of preferred stock, par value $.01 per share.

Initial Public Offering and Related Events In February 2004, the Company completed the IPO of 13,800,000 shares of its Class A common stock at $12.00 per share. The Company did not receive any proceeds from the initial sale of Class A common stock.

Before completion of the IPO, the Company entered into various agreements to complete the separation of the Shallow Water business from Transocean, including an employee matters agreement, a master separation agreement and a tax sharing agreement. The master separation agreement provides for, among other things, the assumption by the Company of liabilities relating to the Shallow Water business and the assumption by Transocean of liabilities unrelated to the Shallow Water business, including the indemnification of losses that may occur as a result of certain of the Company s ongoing legal proceedings. See Note 9.

In February 2004, the Company recorded an increase in equity related to net liabilities attributable to Transocean s business of $0.4 million for which legal title had not been transferred to Transocean as of the IPO date in accordance with the master separation agreement between the Company and Transocean. The indemnification by Transocean was recorded as a credit to additional paid-in capital and a corresponding related party receivable from Transocean.

In conjunction with the IPO, the Company entered into a tax sharing agreement with Transocean. See Note 8.

Secondary Stock Offerings Secondary stock offerings were completed in September 2004, December 2004 and May 2005 in which Transocean sold an additional 17,940,000 shares, 14,950,000 shares and 13,310,000 shares, respectively, of the Company s Class A common stock. At the closing of the December 2004 secondary stock offering, Transocean converted all of its unsold shares of Class B common stock into an equal number of Class A common stock shares, resulting in there being no shares of Class B common stock outstanding. The Company received no proceeds from the secondary stock offerings. As of June 30, 2005, Transocean had sold all of its remaining shares of the Company s common stock.

Note 4 Delta Towing

Prior to January 1, 2006, the Company owned a 25 percent equity interest in Delta Towing LLC (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 Company valued these notes at $80.0 million and no value was assigned to the ownership interest in Delta Towing. Delta Towing s property and equipment, with a net book value of $29.0 million at March 31, 2006, are collateral for the Company s notes receivable. The remaining 75 percent ownership interest was held by affiliates of Edison Chouest Inc. (Chouest), which also loaned Delta Towing $3.0 million. See Note 5.

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Under FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* (FIN 46), Delta Towing was considered a variable interest entity because its equity was not sufficient to absorb the joint venture s expected future losses. The Company was deemed to be the primary beneficiary of Delta Towing for accounting purposes because it had the largest percentage of investment at risk through the secured notes held by the Company and would thereby absorb the majority of the expected losses of Delta Towing. The Company adopted FIN 46 and, accordingly, consolidated Delta Towing effective December 31, 2003. As of December 31, 2005 all intercompany accounts have been eliminated in consolidation as a result of the adoption of FIN 46, as well as all intercompany transactions during the three months ended March 31, 2005.

In January 2006, the Company purchased Chouest s 75% interest in Delta Towing for one dollar and paid $1.1 million to retire 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 credit of $3.9 million, including the $1.8 million gain recognized by Delta Towing upon the retirement of the related party debt, which was pushed down to Delta Towing s property assets in its separate financial statements. As of March 31, 2006 all intercompany accounts have been eliminated in consolidation as well as all intercompany transactions during the three months ended March 31, 2006. 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 three months ended March 31, 2006, since Delta Towing was already consolidated in the Company s consolidated financial statements in accordance with 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):

	Third Party		Related Party	
	March 31, 2006	**December 31, 2005**	**March 31, 2006**	**December 31, 2005**
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	10.9	10.9		
Other Debt	1.0	0.4		2.9
Total	17.6	17.0		2.9
Less debt due within one year	1.0	0.4		2.9
Total long-term debt	$ 16.6	$ 16.6	$	$

Third Party Debt Revolving Credit Facility. In December 2003, the Company entered into a two-year $75 million floating-rate secured revolving credit facility (the 2003 Facility). The 2003 Facility expired in December 2005 at which time the Company entered into a two-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

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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.

During the three months ended March 31, 2006 and 2005, the Company recognized $0.3 million and $0.2 million, respectively, in interest expense related to commitment fees on the unused portion of the respective facility. During the three months ended March 31, 2006 and 2005, the Company amortized $0.1 million and $0.3 million, respectively, in deferred financing costs as a component of interest expense. At March 31, 2006 and December 31, 2005, the Company had no borrowings outstanding under the 2005 Facility.

Senior Notes Prior to the IPO, the Company had 6.75%, 6.95%, 7.375%, and 9.5% Senior Notes (the Senior Notes) outstanding. In April 2005, the Company repaid the outstanding balance of $7.7 million related to the 6.75% Senior Notes. As a result, at March 31, 2006, approximately, $2.2 million, $3.5 million, and $10.2 million principal amount of the 6.95%, 7.375%, and 9.5% Senior Notes, respectively, due to third parties were outstanding. The fair value of these notes at March 31, 2006, was approximately $2.2 million, $3.8 million, and $11.1 million, respectively, based on the market valuations. The Company recognized $0.3 million and $0.5 million in interest expense related to these notes for the three months ended March 31, 2006 and 2005, respectively.

Other Debt Third Party 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, 2006 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.

At March 31, 2006, the Company had $1.0 million outstanding under this line of credit which currently bears interest at 15.5% per annum. The Company recognized minimal interest expense in both of the three month periods ended March 31, 2006 and 2005 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. The note was classified as a current obligation in the Company s condensed consolidated balance sheet at December 31, 2005 as Delta Towing was in default on this note. Interest expense related to the note with Chouest was $0.1 million for the three months ended March 31, 2005. No interest expense was incurred during the three months ended March 31, 2006.

Capital Lease Obligations From time to time the Company enters into capital lease agreements for certain drilling equipment. In August 2004, the Company entered into a two-year capital lease agreement for $0.9 million with a final maturity date in July 2006. The Company exercised its option to buy-out the remaining term of this lease agreement in February 2005 for $0.7 million. The Company entered into additional capital lease agreements for $1.1 million each in January 2005 and June 2005. The Company exercised its option to buy-out the remaining term of these lease agreements in November 2005. As of March 31, 2006 and December 31, 2005, the Company had no capital lease obligations. Interest expense, which is not significant, is included in interest expense. Depreciation expense on these assets, which is not significant, is included in depreciation expense.

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Note 6 Other Current Liabilities

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

	March 31, 2006	December 31, 2005
Accrued self-insurance claims	$ 17.9	$ 16.3
Deferred income	6.8	23.3
Accrued payroll and employee benefits	8.8	13.3
Accrued taxes, other than income	11.3	9.2
Other	1.3	0.9
Total other current liabilities	$ 46.1	$ 63.0

Note 7 Supplementary Cash Flow Information

Supplementary cash flow information relating to operations is as follows (in millions):

	Three Months Ended March 31, 2006	2005
Non-cash investing activities:		
Delta Towing purchase price adjustment (a)	$(2.1)	$
Retirement of Delta Towing related party debt (a)	(1.8)	
Non-cash financing activities:		
Equity contributions from parent, net of distributions (b)		7.7

(a) In accounting for the acquisition of Chouest s 75% interest in Delta Towing under the purchase method of accounting, a purchase price credit adjustment of $2.1 million was pushed down to Delta Towing s property assets in its separate financial statements. In addition, the outstanding related party debt of

$2.9 million was retired. Delta Towing paid Chouest $1.1 million to retire the note. Since the acquisition of the Chouest interest in Delta Towing was accounted for under the purchase method of accounting, the gain of $1.8 million that would have been realized on the retirement of the debt was pushed down and resulted in a decrease to Delta Towing s property assets in its separate financial statements. See Note 4.

(b) In connection with the closing of the IPO, the Company completed certain equity transactions related to the Company s separation from Transocean. In the first quarter of 2005, the Company recorded an additional $7.7 million in pre-IPO deferred state tax liabilities that existed at the IPO. This recognition resulted in a $7.7 million reduction in additional paid-in capital, $0.9 million of deferred state tax benefit and a $6.8 million increase in deferred tax liabilities. See Note 8.

Note 8 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. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized.

Until the IPO in February 2004, the Company was a member of an affiliated group that included its parent company, Transocean Holdings, and current and deferred taxes were allocated based upon what the Company s tax provision (benefit) would have been had the Company filed a separate tax return.

Tax Sharing Agreement In connection with the IPO, the Company entered into a tax sharing agreement with 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 for any tax benefit resulting from the delivery by Transocean of its stock to an employee of TODCO in connection with the exercise of an employee stock option. 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.

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.

During the first quarter of 2005, the Company recorded additional $7.7 million in pre-IPO deferred state tax liabilities that existed at the IPO date. The recognition of these pre-IPO deferred state tax liabilities resulted in a $7.7 million reduction in additional paid-in capital, $0.9 million of deferred state tax benefit and a $6.8 million increase in deferred tax liabilities.

In September 2005, Transocean instructed TODCO, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by current and former employees and directors of TODCO from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected TODCO to take a similar deduction in future years to the extent there were profits realized by its current and former employees and directors during those future periods.

It is TODCO s belief that the tax sharing agreement only requires TODCO to pay Transocean for deductions related to stock option exercises by persons who were TODCO employees on the date of exercise. Transocean disagrees with TODCO s interpretation of the tax sharing agreement as it relates to this issue and it believes that TODCO must pay for all stock option exercises, irrespective of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against TODCO.

TODCO recorded its obligation to Transocean based upon its interpretation of the tax sharing agreement. However, due to the uncertainty of the outcome of this dispute, TODCO established a reserve equal to the benefit derived from stock option deductions relating to persons who were not employees of TODCO on the date of the exercise of $40.4 million and $30.9 million at March 31, 2006 and December 31, 2005, respectively. As of December 31, 2005, the deduction related to all current and former employees and directors of TODCO was $94.2 million with only $5.9 million attributable to persons who were employees of TODCO on the date of exercise. Additionally, TODCO has been informed by Transocean that from January 1, 2006 to March 31, 2006, current and former employees and directors of TODCO realized $28.9 million of gains from the exercise of Transocean stock options with $1.9 million relating to persons who were employees of TODCO on the date of exercise. If Transocean s interpretation of the tax sharing agreement prevails, TODCO would recognize a tax benefit for former employee and director stock option exercises and pay Transocean 35% for the deduction. While this would not increase TODCO s tax expense, it would defer utilization of pre-IPO income tax benefits.

The Company estimates it utilized pre-IPO income tax benefits to offset its current federal and state income tax obligations during the three months ended March 31, 2006, of $12.1 million. As of March 31, 2006 and December 31, 2005, the Company estimates it owes Transocean $25.8 million and $14.0 million, respectively, for unpaid balances relating to pre-IPO federal, state and foreign income tax benefits utilized and active TODCO employee Transocean stock option exercises received.

As of March 31, 2006, the Company had approximately $261 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on March 31, 2006, the estimated amount that the Company would have been required to pay Transocean would have been approximately $183 million, or 70% of the pre-IPO tax benefits, at March 31, 2006.

The estimated liabilities to Transocean at March 31, 2006 and the estimated amount of remaining pre-IPO income tax benefits subject to the obligation to reimburse Transocean at March 31, 2006 do not reflect the benefit of the tax

deduction for stock option exercises of former employees who were not employees of TODCO on the date of the exercise and are presented within accrued income taxes related party in the Company s condensed consolidated balance sheets.

Note 9 Commitments and Contingencies

TODCO vs. Transocean Inc. and Transocean Holdings Inc. (Transocean). In connection with the Company s separation from Transocean, the Company executed a tax sharing agreement with Transocean. The agreement provides that the Company must pay Transocean for certain pre-IPO tax benefits utilized or deemed to have been utilized subsequent to the IPO. The agreement also provides that the Company must pay Transocean for any tax benefit resulting from the delivery by Transocean of its stock to an employee of the TODCO Tax Group that results in a tax benefit to the Company. In September 2005, Transocean instructed the Company to take a tax deduction for profits realized by the Company s current and former employees and directors from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected the Company to take a similar deduction in future years to the extent there were profits realized by the Company s current and former employees and directors during those future periods. The Company believes that the applicable provision of the agreement only requires the Company to pay Transocean for deductions related to stock option exercises by persons who were employees of the TODCO Tax Group on the date of exercise and has advised Transocean accordingly. Both parties have issued arbitration demand notices to the other and have requested a Federal Court to select a neutral arbitrator to decide the dispute. In addition, the Company has filed a lawsuit against Transocean in Texas State District Court seeking to have the agreement overturned in its entirety. The dispute is in its earliest stages of development and it is difficult to predict the eventual outcome. In any event, the Company does not expect the outcome of this matter to have a material adverse effect on its consolidated results of operations, financial position or cash flows.

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 arising 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. The trial court granted motions requiring each plaintiff to name the specific defendant or defendants against whom such plaintiff makes a claim and the time period and location of asbestos exposure so that the cases may be properly served. In that regard, a majority of these cases have been assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made may be properly served against specific defendants. As of the date of this report, approximately 699 questionnaires had been submitted. Of those, approximately 103 shared periods of employment by TODCO and Transocean which could lead to claims against either company. The Company has not determined which entity would be responsible for such claims under the Master Separation Agreement between the two companies. 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 its 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, the Company 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.

Litigation 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.

Under the master separation agreement, Transocean has agreed to indemnify the Company for any losses it incurs as a result of the legal proceeding described in the following paragraph. See Note 3.

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). 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.

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 $23.6 million in place as of March 31, 2006 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 (PDVSA), the Venezuelan national oil company.

Self-Insurance The Company is at risk for the deductible 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.

Property litigation settlement In March 2006, the Company received a $4.0 million settlement from a contractor to the operator 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.

Rig Reactivations In anticipation of additional rig reactivations in 2006, the Company has placed orders for equipment with long lead times, including an $8.4 million commitment for eight top-drives and $10.6 million of drill pipe for delivery in 2006.

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Note 10 Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share for the three months ended March 31, 2006 and 2005:

	Three Months Ended March 31,			
	2006		2005	
	(in millions, except per share amounts)			
Numerator:				
Income before income taxes and cumulative effect of change in accounting principle	$	29.2	$	8.1
Cumulative effect of change in accounting principle, net of tax		0.1		
Net income	$	29.3	$	8.1
Denominator:				
Weighted average shares outstanding:				
Basic		61.4		60.0
Employee stock options		0.3		0.5
Restricted stock awards and other		0.3		0.4
Diluted		62.0		60.9
Earnings per common share:				
Basic:				
Earnings before cumulative effect of change in accounting principle	$	0.48	$	0.13
Cumulative effect of change in accounting principle				
Net earnings per common share	$	0.48	$	0.13
Diluted:				
Earnings before cumulative effect of change in accounting principle.	$	0.47	$	0.13
Cumulative effect of change in accounting principle				
Net earnings per common share	$	0.47	$	0.13

For the three months ended March 31, 2006, there were 179,250 shares underlying stock options related to the Company s Class A 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 net income were made in calculating diluted earnings per share for the three months ended March 31, 2006 and 2005.

Note 11 Stock-Based Compensation Plans

TODCO Long-Term Incentive Plan (the 2004 Plan) In February 2004, the Company adopted the 2004 Plan, a long-term incentive plan for certain employees and non-employee directors of the Company, in order to provide additional incentives and to increase the personal stake of participants in the continued success of the Company. The 2004 Plan provided for the grant of options to purchase shares of the Company s Class A common stock, restricted stock, deferred stock units, share appreciation rights, cash awards, supplemental payments to cover tax liabilities associated with the aforementioned types of awards, and performance awards. Most awards under the 2004 Plan vest over a three-year period. A maximum of 3,000,000 shares of the Company s Class A common stock were reserved for issuance under the 2004 Plan. In May 2005, the stockholders approved the TODCO 2005 Long-Term Incentive Plan and no further awards will be granted under the 2004 Plan.

TODCO 2005 Long-Term Incentive Plan (the 2005 Plan) The 2005 Plan was adopted to continue 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 2005 Plan provides for the grant of options to purchase shares of the Company s Class A 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. The number of shares reserved under the 2005 Plan and available for incentive awards is 4,000,000 shares of the Company s Class A common stock. Additionally, any grants or awards under the 2004 Plan that expire or are forfeited, terminated or otherwise cancelled or that are settled in cash in lieu of shares are reserved and available for incentive awards under the 2005 Plan. Any incentive awards other than stock options under the 2005 Plan reduce the shares available for grant by two shares for every one share granted. In addition, options and awards granted provide for accelerated vesting if there is a change in control.

Compensation cost that has been charged against income for the plans for the three month period ended March 31, 2006 and 2005 was $1.5 million and $1.8 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. The Company estimated the forfeiture rate for restricted stock awards for the first quarter of fiscal 2006 based on its historical experience during the preceding two fiscal years which represents the period since the IPO. The adoption of FAS 123(R), discussed in Note 2 to the Condensed Consolidated Financial Statements, resulted in the Company recognizing a credit of $0.1 million, net of tax, from the cumulative effect of the accounting principle change. Due to the fact that stock options, deferred stock units and deferred performance units are issued to a limited number of employees and directors and have no historical forfeitures with none anticipated, no estimate of forfeitures are included for these awards.

As of March 31, 2006, there was $16.2 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted under the 2005 Plan and the 2004 Plan (collectively the Plans). That cost is expected to be recognized over a weighted-average period of 3.0 years. The total fair value of shares vested during the three months ended March 31, 2006 and 2005 was $5.4 million and $3.9 million, respectively. At March 31, 2006, there were 3,224,068 shares remaining available for the grant of awards under the 2005 Plan.

Stock Options The following tables summarize information about TODCO stock options held by employees and non-employee directors of the Company at March 31, 2006:

	Number of Shares	**Weighted Average Exercise Price**	**Aggregate Intrinsic Value (in millions)**	**Weighted-Average Remaining Contractual Life**
Outstanding as of January 1, 2006	718,347	$ 14.49		
Stock options granted	179,250	$ 46.71		
Stock options exercised	36,516	$ 16.09		
Outstanding as of March 31, 2006	861,081	$ 21.14	$ 17.0	8.5 years
Vested and expected to vest as of March 31, 2006	861,081	$ 21.14	$ 17.0	8.5 years
Exercisable as of March 31, 2006	480,125	$ 12.92	$ 12.7	8.0 years

The total intrinsic value of stock options exercised during the three months ended March 31, 2006 and 2005 was $1.0 million and $2.5 million, respectively. Intrinsic value represents the difference between the Company s stock price at the time the option was exercised and the exercise price, multiplied by the number of options exercised. The aggregate intrinsic value in the table above represents the total pretax intrinsic value (the difference between the Company s closing stock price on the last trading day of the first quarter of fiscal 2006 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on March 31, 2006. This amount changes based on the fair market value of the Company s stock.

The fair value of the options granted under the 2004 Plan and the 2005 Plan was estimated using the Black-Scholes options pricing model with the following weighted average assumptions:

	Three Months Ended March 31,	
	2006	**2005**
Dividend yield	0.00%	0.00%

Expected price volatility	40.2%	32.0%
Risk-free interest rate	4.47%	3.67%
Expected life of options (in years)	6.0	5.0
Weighted-average fair value of options granted	$ 21.57	$ 7.33

The expected price volatility was based on the historical volatility of the Company s stock over the past two years. The expected term of options granted is derived from the output of the option valuation model and represents the period of time that options are expected to be outstanding. The risk-free interest rate for periods within the

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contractual life of the options is based on the U. S. Treasury constant maturity provided by the Federal Reserve Bank.

In 2004, the Company granted 730,000 options with immediate vesting provisions and 705,000 options with two year vesting terms. However, stock options granted by the Company generally are granted with a three year vesting term. Option awards are granted with an exercise price equal to the market price of the Company s stock at the date of grant. All options granted by the Company have a ten-year contractual life.

During the three month periods ended March 31, 2006 and 2005, the Company received $0.8 million and $2.6 million, respectively, in stock option proceeds of which $0.2 million and $0.4 million, respectively, was the result of the tax benefits recognized as a result of the exercise of the options.

Other Awards

Also under the 2005 Plan and the 2004 Plan, the Company awarded shares of restricted stock, deferred performance units, and deferred stock awards to certain employees and non-employee directors of the Company. The following table summarizes the information related to the these awards.

	Number of Shares	**Weighted-Average Fair Value at Grant Date**
Restricted Stock:		
Nonvested outstanding at January 1, 2006	239,922	$ 18.70
Awards vested	83,816	$ 18.49
Awards granted	134,851	$ 35.83
Awards forfeited	4,151	$ 20.92
Nonvested outstanding at March 31, 2006	286,806	$ 26.78
Deferred Stock Units:		
Vested, not issued, at January 1, 2006	24,290	$ 24.20
Awards vested and granted		
Vested, not issued, at March 31, 2006	24,290	$ 24.20
Deferred Performance Awards:		
Nonvested outstanding at January 1, 2006	173,481	$ 10.10
Awards vested		
Awards granted	143,400	$ 21.18
Awards forfeited		
Nonvested outstanding at March 31, 2006	316,881	$ 15.11

Restricted Stock Awards During the three months ended March 31, 2006 and 2005, the Company granted 134,851 and 168,488 shares of restricted stock, respectively. The weighted average fair value of restricted stock granted during the three months ended March 31, 2006 and 2005 was $35.83 and $21.26, respectively. For restricted stock awards, at the date of grant, the recipient has substantially all the rights of a stockholder, subject to certain restrictions on transferability and a risk of forfeiture. Although restricted stock awards typically vest over a three year period beginning at the date of grant, there were 156,496 restricted stock awards granted in conjunction with the IPO which vested in July 2005.

Deferred Stock Awards Although the deferred stock awards vest immediately upon grant, stock certificates are not issued until certain requirements are met, typically five years of service or separation from service as a member of the Board of Directors. Since the deferred stock awards vest immediately, the compensation expense associated with the awards is recorded in the month granted. During the three months ended March 31, 2006 and 2005, no grants of deferred stock units were made by the Company.

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Deferred Performance Units During the three months ended March 31, 2006 and 2005, the Company granted 143,400 shares and 167,481 shares, respectively, of deferred performance units to various employees of the Company. The fair value of the deferred performance units granted for the three months ended March 31, 2006 and 2005 was $21.18 and $10.10, respectively. The expected volatility is based on the historical volatility of the Company s stock over the prior two years. The total maximum number of the deferred performance units earned and awarded from the total number of shares granted is based upon the level of achievement by the Company of a predetermined performance standard over a three-year period commencing on January 1st of the year granted. None of the deferred performance units have vested as of March 31, 2006.

The fair value of the deferred performance unit awards granted under the 2004 Plan and the 2005 Plan was estimated on the date of grant using the Monte Carlo simulation method incorporating the adjusted capital asset pricing model using the following weighted average assumptions:

	Three Months Ended March 31,	
	2006	**2005**
Dividend yield	0.00%	0.00%
Expected price volatility	40.2%	32.0%
Weighted-average fair value of options granted	$ 21.18	$ 10.10

Note 12 Gain on Disposal of Assets

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 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.

The Company recorded a $1.1 million net gain on disposal of assets in the first quarter of 2005. This gain resulted from the sale of drill pipe and miscellaneous equipment for $1.1 million for a gain of $0.5 million and the sale of three marine support vessels by Delta Towing for $1.5 million for a gain of $0.6 million.

Note 13 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, jackup drilling rigs and a land rig in Trinidad, jackup drilling rigs and a platform rig in Mexico, a jackup drilling rig in Angola and one jackup drilling rig in Colombia, as well as land drilling rigs located in Venezuela. 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, Other International Segment and Delta Towing Segment.

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

	U.S. Gulf of Mexico Segment	**U.S. Inland Barge Segment**	**Other International Segment**	**Delta Towing Segment**	**Corporate & Other(a)**	**Total**
Three Months Ended:						
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	19.1	7.5	7.4	(8.4)	45.2
March 31, 2005						
Operating revenues	$ 51.7	$ 30.0	$ 20.1	$ 10.1	$	$ 111.9
Depreciation	12.7	5.7	4.4	1.2		24.0

Operating income (loss)	13.3	2.8	(0.1)	2.9	(7.2)	11.7

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

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

	March 31, 2006	December 31, 2005
U.S. Gulf of Mexico Segment	$ 245.4	$ 252.2
U.S. Inland Barge Segment	167.1	161.3
Other International Segment	168.9	164.6
Delta Towing Segment	44.5	55.6
Corporate and Other	234.9	191.3
Total assets	$ 860.8	$ 825.0

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 interest in Delta Towing. Geographic information about the Company s operations was as follows (in millions):

	Three Months Ended March 31,	
	2006	2005
Operating Revenues		
United States	$ 139.3	$ 91.8
Other countries	44.3	20.1
Total operating revenues	$ 183.6	$ 111.9

	March 31, 2006	December 31, 2005
Long-Lived Assets		
United States	$ 376.0	$ 404.2
Other countries	118.5	113.1
Total long-lived assets	$ 494.5	$ 517.3

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.

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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 those 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 operate 18 jackup and three submersible rigs in the U.S. Gulf of Mexico shallow water market which begins at the outer limit of the transition zone and extends to water depths of about 350 feet. Our jackup rigs in this market 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.

U.S. Inland Barge Segment Our barge rig fleet currently operating in this market 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.

Other International Segment Our other operations are currently conducted in Angola, Colombia, Mexico, Trinidad and Venezuela. We operate one jackup rig in Angola and one jackup rig in Colombia. In Mexico, we operate two jackup rigs and a platform rig. Additionally, we have two jackup rigs and a land rig in Trinidad and eight land rigs in Venezuela. We may pursue selected opportunities in other international areas from time to time.

Delta Towing Segment Delta Towing LLC (Delta Towing) operates a fleet of U.S. marine support vessels consisting primarily of shallow water tugs, crewboats and utility barges 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 units in the market segments in which we operate. Supply and demand for drilling units 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.

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.

Industry Background, Trends and Outlook

The drilling industry in the U.S. Gulf Coast is highly cyclical and is typically driven by general economic activity and changes in actual or anticipated oil and gas prices. We believe that both our earnings and demand for our rigs will typically be correlated to our customers expectations of energy prices, particularly natural gas prices, and that sustained energy price increases will generally have a positive impact on our earnings.

We believe there are several trends that should benefit our operations, including:

High Natural Gas Prices. While U.S. natural gas prices are volatile, the rolling twelve-month average price of natural gas has increased from $2.11 in January 1994 to $9.21 in March 2006. High natural gas prices in the United States have resulted in more exploration and development drilling activity and higher utilization and dayrates for drilling companies like us. If high natural gas prices are sustained, we expect this trend to continue.

Need for Increased Natural Gas Drilling Activity. From 1995 to 2004, U.S. demand for natural gas grew at an annual rate of 0.7% while its supply grew at an annual rate of 0.2%. We believe that this supply and demand growth imbalance will continue if demand for natural gas continues to increase and production decline rates continue to accelerate. Even though the number of U.S. gas wells drilled has increased overall in recent years, a corresponding increase in production has not been realized. We believe that an increase in U.S. drilling activity will be required for the natural gas industry to meet the expected increased demand for, and compensate for the slowing production of, natural gas in the United States.

Trend Towards Drilling Deeper Shallow Water Gas Wells. A current trend by oil and gas companies is to drill deep gas wells along the U.S. Gulf Coast in search of new and potentially prolific untapped natural gas reserves. We believe that this trend towards deeper drilling will benefit premium jackup rigs as well as barge rigs and submersible rigs that are capable of drilling deep gas wells. In addition, this trend will indirectly benefit conventional jackup fleets, such as ours, as the use of premium rigs in the U.S. Gulf Coast to drill deep wells should reduce the supply of rigs available to drill shallower wells.

Redeployment of Jackup 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. This favorable supply environment has contributed to increased jackup utilization and dayrates.

New Building of Jackup Rigs. In response to the improved market conditions, our competitors and speculators have recently begun ordering new jackup drilling rigs. We believe there are currently 62 jackup rigs on order with delivery dates ranging from 2006 to 2009. 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 could curtail a further strengthening of utilization and dayrates, or reduce them. However, the worldwide jackup fleet is aging and will need to be replaced at some point. Currently, the average age worldwide is approximately 24 years old. In addition, attrition continues and was recently accelerated when the U.S. Gulf of Mexico experienced two major hurricanes, which destroyed or significantly damaged nine jackup drilling rigs.

Market conditions for our U.S. Gulf Coast jackup fleet improved beginning in the third quarter of 2003 and continued through the first quarter of 2006. As shown in the following table, from the first quarter of 2005 through the first quarter of 2006, our average revenue per day for U.S. Gulf of Mexico jackups and submersibles improved by 76%. During the same period, average revenue per day for our U.S. inland barges improved by 35%. As of April 24, 2006, 11 of our 16 marketed jackup and submersible rigs working in the U.S. Gulf Coast were operating at dayrates ranging from $64,900 to $119,000. As of April 24, 2006, 16 of our 17 marketed inland barges were

operating at dayrates ranging from $20,400 to $41,700. We anticipate that the declining jackup rig supply in the U.S. Gulf Coast due to the redeployment of rigs to international locations and the trend towards more deep gas well drilling will continue to result in improved utilization and high dayrates. As a result, we are actively pursuing long-term contracts with our customers to reactivate our five cold-stacked U. S. Gulf of Mexico jackup rigs. Additionally, we are pursuing long-term contracts to reactivate some of our ten cold-stacked inland barge rigs.

The following table shows our average rig revenue per day and utilization for the quarterly periods ended on or prior to March 31, 2006 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, 2004	**June 30, 2004**	**September 30, 2004**	**December 31, 2004**	**March 31, 2005**	**June 30, 2005**	**September 30, 2005**	**December 31, 2005**	**March 31, 2006**
Average Rig Revenue Per Day:									
U.S. Gulf of Mexico Jackups and Submersibles	$30,600	$30,700	$33,800	$39,900	$44,600	$51,000	$56,700	$60,800	$78,700
U.S. Inland Barges	20,300	22,500	22,900	23,000	25,000	27,800	29,600	30,800	33,700
Other International	40,000	37,500	34,600	29,400	28,400	33,900	31,300	37,100	45,700
Utilization:									
U.S. Gulf of Mexico Jackups and Submersibles	43%	50%	54%	56%	56%	56%	56%	51%	50%
U.S. Inland Barges	40%	42%	45%	46%	46%	51%	53%	55%	60%
Other International	29%	29%	33%	39%	56%	55%	56%	63%	67%

Our contracts to provide drilling services are individually negotiated and vary in their terms and provisions. We obtain most of our contracts through competitive bidding against other contractors. Drilling contracts generally provide for payment on a dayrate basis, with higher rates while the drilling unit is operating and lower rates for periods of mobilization or when drilling operations are interrupted or restricted by equipment breakdowns, adverse environmental conditions or other factors.

A dayrate drilling contract generally extends over a period of time covering the drilling of a single well or group of wells or covering a stated term. These contracts typically can be terminated by the customer under various circumstances such as the loss or destruction of the drilling unit or the suspension of drilling operations for a specified period of time as a result of a breakdown of major equipment. The contract term in some instances may be extended by the customer exercising options for the drilling of additional wells or for an additional term, or by exercising a right of first refusal. Historically, most of our drilling contracts have been short-term or on a well-to-well basis. However, due to current market conditions, a declining supply of jackup rigs in the U.S. Gulf of Mexico and our recent rig reactivations, we have been entering into longer term drilling contracts. As of April 17, 2006, we had an estimated 3,921 rig days in 2006 and an estimated 1,382 rig days in 2007 contracted for under term contracts (as opposed to well-by-well contracts) of varying duration. These estimates include rig days expected to be completed under contracts the term of which begins upon reactivation of a cold stacked rig, as discussed further below. Included in these estimates are the remaining terms for three contracts we have executed with Pemex Exploration and Production Company (PEMEX) for rigs *THE 205* (206 days), *THE 206* (433 days) and *Platform Rig 3* (742 days).

In response to strengthening demand for drilling rigs, we began reactivating certain of our cold-stacked rigs beginning in the second quarter of 2005 and continuing into 2006. We did so, however, only if we first obtained a term drilling contract for each reactivated rig at a dayrate sufficient to recover, over the full term of the contract, all of our expected operating expenses of performing the contract plus all, or a substantial portion of, our anticipated costs of reactivating the rig.

Since December 31, 2004, we have reactivated or commenced reactivation of eight cold stacked rigs consisting of three jackup rigs, two submersible rigs and three barge rigs. In each case, these reactivations are supported by term drilling contracts at dayrates sufficient to recover over the term of the contract all of our expected operating expenses of performing the contract plus all, or a substantial portion of, the anticipated costs of reactivating the rig. These completed or planned rig reactivations are described below.

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In February 2006, we signed a contract to reactivate *THE 256*, a jackup drilling rig, against a one-year term contract. The cost to reactivate and upgrade the rig is estimated at $18.6 million consisting of approximately $12.4 million of reactivation costs that will be expensed over the 150-day reactivation period and an additional $6.2 million for capital upgrades to the rig. *THE 256* is expected to begin drilling operations by July 2006 at a dayrate of approximately $105,000 per day.

In December 2005, we reached an agreement to reactivate *THE 252*, a jackup drilling rig. The cost to reactivate and upgrade the rig is anticipated to be approximately $13.5 million, including $4.5 million for capital upgrades to the rig. Upon the completion of the reactivation, expected to be May 2006, the rig will commence operations under a one year contract at a dayrate of approximately $85,000 per day.

In November 2005, we signed term contracts for a barge rig and two submersible drilling rigs. *Rig 1*, a conventional inland barge, was reactivated for a cost of approximately $3.8 million, including $1.8 million of capital expenditures against a one-year term contract. *Rig 1* began drilling operations under the contract on March 10, 2006 at a dayrate of approximately $30,000 per day. *THE 77*, an offshore submersible drilling rig, will be reactivated and upgraded against a nine-month term contract. The reactivation is expected to be completed in June 2006 at a cost of approximately $21 million, including $7.0 million of capital expenditures. At that time, drilling operations are expected to commence at a dayrate of approximately $85,000 per day. The offshore submersible drilling rig, *THE 78*, will be reactivated and upgraded at a cost of approximately $13.5 million, of which $5.2 million will be capitalized and $8.3 million will be expensed during the reactivation period. The reactivation of this rig is expected to be completed in May 2006 when it will begin operating under a six-month term contract at a dayrate of approximately $73,000 per day.

In October 2005, we signed a six-month contract with an independent oil and gas company for our cold stacked inland barge, *Rig 49.* The total cost to reactivate the rig was approximately $3 million. *Rig 49* began drilling operations in the inland waterways of Texas and Louisiana in December 2005 at a dayrate of approximately $36,000 per day.

In June 2005, we signed a seven-month contract with an independent oil and gas company for the reactivation of our cold stacked inland barge rig, *Rig 28.* The rig reactivation was completed in late July 2005 at a cost of $2.6 million. The reactivation costs included $2.4 million of repairs and maintenance, which was expensed as incurred, and $0.2 million of capital equipment. Operations began in July 2005 at a dayrate of $26,000 per day.

In May 2005, we signed a contract with Angola Drilling Company Limited (ADC) to reactivate our cold stacked jackup rig, *THE 185*, for a two-year drilling contract with two one-year options. Following a shipyard reactivation and mobilization to Angola, *THE 185* began drilling operations in September 2005 at a dayrate of approximately $59,500 per day. We spent $7.3 million to reactivate *THE 185*, which was expensed as incurred. Additionally, we spent $3.4 million to mobilize the rig to Angola, which was deferred and is being amortized to expense over the two-year term of the drilling contract. We received reimbursement from ADC of $7 million for the reactivation and mobilization costs, which was treated as deferred revenue and is being amortized to revenue over the two-year term of the drilling contract.

In the third quarter of 2003, we were awarded contracts with PEMEX for two of our jackup rigs and a platform rig. After upgrades to comply with contract specifications, one rig, *THE 206*, began operating on a 720-day contract in early November 2003 at a contract dayrate of approximately $42,000. A new 615-day contract was awarded for *THE 206* at dayrates of approximately $64,000 which became effective in late October 2005. The other jackup rig, *THE 205*, began operating in early December 2003 on a 1,081-day contract at a contract dayrate of approximately $39,000. The platform rig contract 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.

We expect that we may reactivate or commit to reactivate additional cold-stacked rigs during the remainder of 2006, 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 anticipation of reactivating cold-stacked rigs, we have ordered certain rig components and equipment that have extended delivery times. See " Liquidity and Capital Resources Sources of Liquidity and Capital Expenditures, below.

We anticipate that market conditions should provide us an opportunity to obtain, during 2006, term contracts with customers for the reactivation and return to service of all five of our remaining cold stacked U.S. Gulf of Mexico jackup rigs. We estimate that it will cost approximately $55 to $60 million in the aggregate to return these rigs to service. Additionally, we anticipate that we should be able to obtain, during 2006, term contracts with customers to reactivate and return to service up to six of our cold stacked 2,000 or 3,000 horsepower inland barge rigs. Based upon our historical experience and previous rig reactivation assessments, we believe the estimated costs to prepare these inland barge rigs for service would be approximately $6 to $10 million per rig. The amounts we estimate for restoring cold stacked rigs to service are based on our projections of the costs of equipment, supplies and services, which have been rising and are becoming more difficult to project. In addition to the uncertainty of projecting costs in a time of increasing prices, our estimates of rig reactivation costs are also subject to numerous other variables including further rig deterioration over time, the availability and cost of shipyard facilities, customer specifications, and the actual extent of required repairs and maintenance and optional upgrading of the rigs. The actual amounts we ultimately pay for returning these rigs to service could, therefore, vary substantially from our estimates.

During the second quarter of 2006, in addition to the reactivation and contract preparation work discussed above, we anticipate that *THE 202* will continue to be out of service until mid-June. To date, we have incurred costs of $5.6 million of which $3.0 million was incurred in the first quarter of 2006. We anticipate additional costs of $2.0 million as work is completed to repair damage sustained during a jacking incident in the fourth quarter of 2005. Four of our inland barges are anticipated to be out for scheduled repairs and maintenance for approximately 57 days. We anticipate that these scheduled maintenance projects will cost approximately $2.0 million. *THE 205*, working in Mexico, will be brought to a shipyard in the U.S. for scheduled repairs and maintenance and will be out of service for approximately 45 days. The repairs and maintenance are expected to cost approximately $4.0 million.

During the third quarter of 2005, we experienced two major hurricanes in the U.S. Gulf of Mexico, which 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, which will be exceeded in both incidents. Currently, we have recognized expense of $0.8 million through the first quarter of 2006 for damage sustained during Hurricane Katrina. We also incurred $3.8 million in expenses related to damages caused by Hurricane Rita. We recorded $2.8 million of claims receivable for the repair amount incurred above the $1.0 million insurance deductible related to losses sustained during Hurricane Rita. All expenses incurred during the first quarter of 2006 and any remaining expenses incurred related to damage caused by Hurricane Rita will be recorded as a claims receivable.

In January 2005, we retained Simmons & Company International to explore alternatives for the disposition of our Venezuelan land drilling business, which is not viewed by us as being core to our ongoing offshore drilling business. The evaluation may result in the sale of some or all of our Venezuelan assets.

In October 2005, we renewed our principal insurance coverages for property damage, liability and occupational injury and illness for a one-year term. Generally, our deductible levels under the new 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 applies in the event of a windstorm. Previously, our deductible level under these policies was $1.0 million per occurrence with no windstorm limits. In addition, in an effort to control premium costs, we reduced our insurance coverage to 70% of our losses in excess of the applicable deductible and we are uninsured for 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.

Our premium cost increased from approximately $8 million to approximately $15 million under these new policies, which also included an increase of approximately $340 million for insured values. 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.

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 other than the adoption of Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R) which is discussed below, there have been no significant changes during the three months ended March 31, 2006 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, 2005.

Stock-Based Compensation Expense

Effective January 1, 2003, the we adopted the fair value method of accounting for stock-based compensation using the prospective method of transition under Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-based Compensation* (SFAS 123). Under the prospective method and in accordance with the provisions of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (SFAS 148), the recognition provisions were applied to all employee awards granted, modified or settled after January 1, 2003. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123R using the modified prospective transition method and therefore have not restated results for prior periods. Under this transition method, stock-based compensation expense for the first quarter of fiscal 2006 includes compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provision of SFAS 123. Stock-based compensation expense for all stock-based compensation awards granted after January 1, 2006 is based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R. As a result of adopting SFAS 123 in an earlier period, the adoption of SFAS 123R in the first quarter of 2006 had an immaterial income effect. Under the fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award, which is generally a vesting term of three years. Under the guidelines of SFAS 123, we recognized forfeitures in the period in which they occurred. As a result of our adoption of SFAS 123R, the estimate of forfeitures resulted in a one-time cumulative adjustment credit to income of $0.1 million, net of tax. In March 2005, the Securities and Exchange Commission (the SEC) issued Staff Accounting Bulletin No. 107 (SAB 107) regarding the SEC s interpretation of SFAS 123R and the valuation of share-based payments for public companies. We have applied the provisions of SAB 107 in our adoption of SFAS 123R.

Determining the appropriate fair value model and calculating the fair value of share-based payment awards require the input of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. The assumptions used in calculating the fair value of share-based payment awards represent management s best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our stock-based

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compensation expense could be materially different in the future. As of March 31, 2006, there was $16.2 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements that have been granted. That cost is expected to be recognized over a weighted-average period of 3.0 years. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, the stock-based compensation expense could be significantly different from what we have recorded in the current period. See Notes 2 and 11 to the Condensed Consolidated Financial Statements for a further discussion on stock-based compensation.

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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,	
	2006	2005
	(In millions except per day data)	
U.S. Gulf of Mexico Segment:		
Operating days	944	1,159
Available days(a)	1,890	2,070
Utilization(b)	50%	56%
Average rig revenue per day(c)	$ 78,700	$ 44,600
Operating revenues	$ 74.3	$ 51.7
Operating and maintenance expenses(d)	44.0	25.7
Depreciation	10.7	12.7
Operating income	19.6	13.3
U.S. Inland Barge Segment:		
Operating days	1,454	1,202
Available days(a)	2,430	2,624
Utilization(b)	60%	46%
Average rig revenue per day(c)	$ 33,700	$ 25,000
Operating revenues	$ 49.0	$ 30.0
Operating and maintenance expenses(d)	25.2	22.3
Depreciation	5.5	5.7
Gain on disposal of assets, net	(0.8)	(0.8)
Operating income	19.1	2.8
Other International Segment:		
Operating days	970	709
Available days(a)	1,440	1,260
Utilization(b)	67%	56%
Average rig revenue per day(c)	$ 45,700	$ 28,400
Operating revenues	$ 44.3	$ 20.1
Operating and maintenance expenses(d)	31.7	15.5
Depreciation	5.1	4.4
Loss on disposal of assets, net		0.3
Operating income (loss)	7.5	(0.1)
Delta Towing Segment:		
Operating revenues	$ 16.0	$ 10.1
Operating and maintenance expenses(d)	6.4	5.4
Depreciation	1.0	1.2
General and administrative expenses	1.3	1.2
Gain on disposal of assets, net	(0.1)	(0.6)
Operating income	7.4	2.9
Total Company:		
Rig operating days	3,368	3,070
Rig available days(a)	5,760	5,954
Rig utilization(b)	58%	52%

Average rig revenue per day(c)	$ 49,800	$ 33,200
Operating revenues	$ 183.6	$ 111.9
Operating and maintenance expenses(d)	107.3	68.9
Depreciation	22.3	24.0
General and administrative expenses	9.7	8.4
Gain on disposal of assets, net	(0.9)	(1.1)
Operating income	45.2	11.7

(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.

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Three Months Ended March 31, 2006 and 2005

Operating Revenues. Total operating revenue increased $71.7 million, or 64%, during the first quarter of 2006 as compared to the same period in 2005. Overall average rig revenue per day increased from $33,200 in the first quarter of 2005 to $49,800 for the three months ended March 31, 2006. The increase in average rig revenue per day reflects the continued improvement of market conditions in the U.S. Gulf Coast, the commencement of operations in Angola and Colombia in the last half of 2005 and additional land rigs operating in Trinidad and Venezuela. Average rig utilization for our overall drilling rig fleet increased to 58% for the first quarter of 2006 from 52% in the first quarter of 2005.

Operating revenues for our U.S. Gulf of Mexico segment increased $22.6 million, or 44%, during the first quarter of 2006 as compared to the same period in 2005. In the three months ended March 31, 2006, we continued to achieve higher average rig revenue per day for our jackup and submersible drilling fleet as a result of our success in obtaining contracts with our customers at higher dayrates in response to increased market demand and decreased jackup drilling rig supply in the U.S. Gulf of Mexico. Average revenue per day increased to $78,700 for the three months ended March 31, 2006, up from $44,600 for the three months ended March 31, 2005, which resulted in an additional $32.4 million in operating revenues. Results for the first quarter of 2006 reflect a decrease in utilization in this segment, after giving effect to the transfers of the jackup drilling unit *THE 156* from the U.S. Gulf of Mexico segment to our Other International segment in the fourth quarter of 2005. This resulted principally from scheduled maintenance on *THE 203* and the continuance of the repairs began in the fourth quarter of 2005 relating to the damage sustained by *THE 202* during a jacking incident. The decreased utilization accounted for a $5.6 million decrease in operating revenues in the first quarter of 2006 as compared to the same period in 2005. *THE 156* generated operating revenues of $4.2 million in the first quarter of 2005.

Operating revenues for our U.S. Inland Barge segment increased $19.0 million, or 63%, during the first quarter of 2006 as compared to the same period in 2005, due to higher average rig revenue per day and utilization. This market has continued to improve since the first quarter of 2005 with average rig revenue per day increasing from $25,000 for the first quarter of 2005 to $33,700 for the comparable period in 2006. This increase resulted in additional operating revenues of $12.7 million. Utilization of our inland barge fleet was 60% for the first quarter of 2006, as compared to 46% for the comparable period in 2005, which resulted in a $6.3 million increase in operating revenues.

Operating revenues for our Other International segment were $44.3 million for the first quarter of 2006 for an increase of $24.2 million, or 120%, over operating revenues for the first quarter of 2005. This increase reflects the commencement of operations in Angola in September 2005 and in Colombia in December 2005. Additionally, a land rig began operating in Trinidad in the last quarter of 2005 and an additional land rig began operations in Venezuela in the first quarter of 2006. The commencement of operations in Angola in September 2005 contributed an additional $6.7 million in operating revenues during the first quarter of 2006. Our Colombian operations had operating revenues of $9.5 million for the three months ended March 31, 2006. The land rig in Trinidad contributed $2.5 million in operating revenues in the first quarter of 2006 and the additional land rig in Venezuela contributed $1.6 million in revenue. Increased daily revenue for all other operations resulted in a favorable variance of $4.4 million, offset by a decrease of $0.5 million due to slightly lower utilization for these operations.

The operations of Delta Towing contributed $16.0 million in operating revenues during the first quarter of 2006, an increase of $5.9 million, or 58%, as compared to the first quarter of 2005. Improved U.S. Gulf Coast market conditions and increased demand for marine support vessels resulted in Delta Towing s revenue increase.

Operating and Maintenance Expenses. Total operating and maintenance expenses increased $38.4 million, or 56%, in the first quarter of 2006 as compared to operating expenses of $68.9 million for the comparable period in 2005.

Operating and maintenance expenses for our U.S. Gulf of Mexico segment were $18.3 million higher for the three months ended March 31, 2006 than the first quarter of 2005 primarily due to increased repair and maintenance costs of $12.3 million of which the majority was incurred in reactivating four of our cold-stacked rigs. We incurred additional personnel costs of $3.0 million principally related to increased wages due to additional personnel employed in the first quarter of 2006 as compared to the same period in 2005. Insurance claim expense related to our jackup rig, *THE 202*, resulted in an additional $2.8 million in expense in the first quarter of 2006 as compared to the first quarter of 2005.

Our U.S. Inland Barge segment had $2.9 million higher operating and maintenance expenses in the first quarter of 2006 as compared to the first quarter of 2005 primarily due to higher personnel costs of $3.8 million primarily due to increased rig personnel resulting from the additional operating rigs in the first quarter of 2006 as compared to the same period in 2005. Repair and maintenance costs also increased by $0.5 million in the first quarter of 2006 as compared to the same period in 2005, primarily due to the costs incurred to reactivate *RIG 1*. These cost increases were offset by a decrease of $2.7 million in personal injury and insurance claim expense in the first quarter of 2006 when compared to the first quarter of 2005. This is principally the result of a property litigation settlement of $4.0 million received from a contractor to the operator on our 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 our employees on board the rig.

Operating and maintenance expenses for our Other International segment were $16.2 million higher for the three months ended March 31, 2006 than the three months ended March 31, 2005. This increase in expense was due principally to the commencement of operations in Angola ($4.1 million) and in Colombia ($5.8 million). The addition of a land rig in Trinidad and one in Venezuela contributed $1.9 million and $2.0 million, respectively, in additional operating and maintenance expense in the first quarter of 2006 as compared to the first quarter of 2005. Additional costs were incurred to return *RIG 37* in Venezuela to service and perform repair and maintenance costs on *THE 206* in Mexico of $0.7 million and $0.8 million, respectively, when comparing the first quarter of 2006 to the same period in 2005.

Delta Towing operating and maintenance expenses were $1.0 million higher for the three months ended March 31, 2006 when compared to the three months ended March 31, 2005, 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 and increased repairs and maintenance expenses.

General and Administrative Expenses. General and administrative expenses were $9.7 million for the first quarter of 2006 as compared to $8.4 million for the comparable period in 2005. The $1.3 million increase in general and administrative expenses was due primarily to $1.0 million in higher personnel costs.

Gain on Disposal of Assets, Net. 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 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.

The Company recorded a $1.1 million net gain on disposal of assets in the first quarter of 2005. This gain resulted from the sale of drill pipe and miscellaneous equipment for $1.1 million for a gain of $0.5 million and the sale of three marine support vessels by Delta Towing for $1.5 million for a gain of $0.6 million.

Interest Expense. Third party interest expense decreased $0.3 million in the first quarter of 2006 as compared to the comparable period in 2005 primarily due to lower debt balances resulting from the repayment of our 6.75% Senior Notes in April 2005.

Income Tax Expense (Benefit). The 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 tax expense and foreign tax expenses incurred. The income tax expense of $3.5 million for the first quarter of 2005 is principally our obligation to Transocean under the tax sharing agreement and represents amounts we owe Transocean for the utilization of pre-closing federal and state tax benefits. Tax expense for the three months ended March 31, 2005, includes the effect of recognizing an additional $7.7 million in pre-IPO deferred state tax liabilities that existed at the IPO date. The recognition of these pre-IPO deferred state tax liabilities resulted in a $7.7 million reduction in additional paid-in capital, $0.9 million of deferred state tax benefit and a $6.8 million increase in deferred tax liabilities. Without the effect of this deferred state tax benefit, the effective tax rate for the quarter ended March 31, 2005, would have been 37.8%, which is higher than the federal tax rate principally due to

utilization of state tax benefits and the resulting obligation to Transocean, including our inability under the tax sharing agreement to reduce our federal tax benefit obligation for the state tax benefits utilized.

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 for any tax benefit resulting from the delivery by Transocean of its stock to any of our employees in connection with the exercise of an employee stock option. 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.

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.

In September 2005, Transocean instructed us, pursuant to a provision in the tax sharing agreement, to take a tax deduction for profits realized by our current and former employees and directors from the exercise of Transocean stock options during calendar 2004. Transocean also indicated that it expected us to take a similar deduction in future years to the extent there were profits realized by our current and former employees and directors during those future periods.

It is our belief that the tax sharing agreement only requires us to pay Transocean for deductions related to stock option exercises by persons who were our employees on the date of exercise. Transocean disagrees with our interpretation of the tax sharing agreement as it relates to this issue and it believes that we must pay for all stock option exercises, irrespective of whether any employment or other service provider relationship may have terminated prior to the exercise of the employee stock option. As such, Transocean initiated dispute resolution proceedings against us.

We recorded our obligation to Transocean based upon our interpretation of the tax sharing agreement. However, due to the uncertainty of the outcome of this dispute, we established a reserve equal to the benefit derived from stock option deductions relating to persons who were not our employees on the date of the exercise of $40.4 million and $30.9 million at March 31, 2006 and December 31, 2005, respectively. As of December 31, 2005, the deduction related to all of our current and former employees and directors was $94.2 million with only $5.9 million attributable to persons who were our employees on the date of exercise. Additionally, we have been informed by Transocean that from January 1, 2006 to March 31, 2006, our current and former employees and directors realized $28.9 million of gains from the exercise of Transocean stock options with $1.9 million relating to persons who were our employees on the date of exercise. If Transocean s interpretation of the tax sharing agreement prevails, we would recognize a tax benefit for former employee and director stock option exercises and pay Transocean 35% for the deduction. While this would not increase our tax expense, it would defer utilization of pre-IPO income tax benefits.

We estimate we have utilized pre-IPO income tax benefits to offset our current federal and state income tax obligations during the three months ended March 31, 2006, of $12.1 million. As of March 31, 2006 and December 31, 2006, we estimate we owe Transocean $25.8 million and $14.0 million, respectively, for unpaid balances relating to pre-IPO federal, state and foreign income tax benefits utilized and our active employee Transocean stock option exercises received.

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As of March 31, 2006, we have approximately $261 million of estimated pre-IPO income tax benefits subject to the obligation to reimburse Transocean. If an acquisition of beneficial ownership had occurred on March 31, 2006, the estimated amount that we would have been required to pay Transocean would have been approximately $183 million, or 70% of the pre-IPO tax benefits, at March 31, 2006.

The estimated liabilities to Transocean at March 31, 2006 and the estimated amount of remaining pre-IPO income tax benefits subject to the obligation to reimburse Transocean at March 31, 2006 do not reflect the benefit of the tax deduction for stock option exercises of former employees who were not employees of TODCO on the date of the exercise and are presented within accrued income taxes related party in the Company s condensed consolidated balance sheets.

Financial Condition

At March 31, 2006 and December 31, 2005, we had total assets of $860.8 million and $825.0 million, respectively. The $35.8 million increase in assets during the first three months of 2006 is primarily attributable to the $37.4 million increase in cash generated primarily by improved operations. In addition, accounts receivable increased as a result of the continually improving market conditions in our industry by $21.2 million. These increases in assets were partly offset by depreciation expense of $22.3 million.

Liquidity and Capital Resources

Sources and Use of Cash

Three Months Ended March 31, 2006 Compared to Three Months Ended March 31, 2005. Net cash provided by operating activities for the three months ended March 31, 2006 and 2005 was $42.2 million and $8.7 million, respectively. The $33.5 million increase in net cash provided by operating activities is primarily attributable to an increase in net income of $21.2 million. Adjustments to reconcile net income to net cash provided by operating activities were lower in 2006, primarily due to an increase in deferred income of $8.4 million for the three months ended March 31, 2006 as compared to the same period in 2005. Our net income was favorably affected by the continuing improvement in the demand for shallow water drilling services which resulted in our dayrates increasing from $33,200 to $49,800 and our rig utilization percentages increasing from 52% to 58%.

Changes in operating assets and liabilities, net of effect of distributions to related parties, resulted in a $11.2 million increase in cash for the three month period ended March 31, 2006, compared to a $8.5 million decrease in the same period in 2005. This $19.7 million increase is primarily the result of an increase of our income tax balances resulting from the higher revenues and income in the first three months of 2006 as compared to the first three months of 2005.

Net cash used in investing activities was $4.8 million for the three months ended March 31, 2006, compared to $0.1 million used in investing activities for the same period in 2005. The $4.7 million increase in net cash used in investing activities is a result of capital expenditures increasing $3.1 million, after accounting for the purchase price adjustment of $2.1 million resulting from the acquisition of Chouest s 75% interest in Delta Towing, and lower realized proceeds from the sale of assets of $1.6 million for the first three months of 2006 as compared to the first three months of 2005. See Note 7 to the Condensed Consolidated Financial Statements.

Net cash provided by financing activities was $0.0 million for the three month period ended March 31, 2006, as compared to $3.8 million for the same period in 2005. The decrease in cash provided by financing activities was primarily the result of lower net proceeds realized from the issuance of 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, 2006 and 2005. For the three months ended March 31, 2006, our primary uses of cash were operating costs and capital expenditures of $7.9 million, not including the $2.1 million purchase price adjustment recognized in connection with the acquisition of Chouest s 75% interest in Delta Towing (see Note 7 to the Condensed Consolidated Financial Statements). For the three months ended March 31, 2005, our primary uses of cash were operating costs and capital expenditures of $2.7 million. At March 31, 2006, we had $200.4 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 2003, we entered into a two-year $75 million floating-rate secured revolving credit facility (the 2003 Facility). The 2003 Facility expired in December 2005 at which time we entered into a two-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.

At March 31, 2006, and December 31, 2005, 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, 2006) 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, 2006, the Company had $1.0 million outstanding under this line of credit which currently bears interest at 15.5% per annum. The Company recognized minimal interest expense in both of the three month periods ending March 31, 2006 and 2005 related to the Venezuela line of credit. There was an outstanding balance of $0.4 million under this line of credit at December 31, 2005.

We expect capital expenditures, primarily for rig refurbishments and the purchase of capital equipment, to be approximately $30.5 million for the remainder of 2006, including approximately $17.2 million for announced 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.

We anticipate that market conditions should provide us an opportunity to obtain, during 2006, term contracts with customers for the reactivation and return to service of all five of our remaining cold stacked U.S. Gulf of Mexico jackup rigs. We estimate that it will cost approximately $55 to $60 million in the aggregate to return these rigs to service. Additionally, we anticipate that we should be able to obtain, during 2006, term contracts with customers to reactivate and return to service up to six of our cold stacked 2,000 or 3,000 horsepower inland barge rigs. Based upon our historical experience and previous rig reactivation assessments, we believe the estimated costs to prepare these inland barge rigs for service would be approximately $6 to $10 million per rig. The amounts we estimate for restoring cold stacked rigs to service are based on our projections of the costs of equipment, supplies and services, which have been rising and are becoming more difficult to project. In addition to the uncertainty of projecting costs in a time of increasing prices, our estimates of rig reactivation costs are also subject to numerous other variables including further rig deterioration over time, the availability and cost of shipyard facilities, customer specifications, and the actual extent of required repairs and maintenance and optional upgrading of the rigs. The actual amounts we ultimately pay for returning these rigs to service could, therefore, vary substantially from our estimates. In anticipation of reactivating some of these rigs, we have already placed orders for equipment with long lead times, including an $8.4 million commitment for eight top-drives and $10.6 million of drill pipe for delivery in 2006.

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, 2006, 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, 2005. In addition, there has been no material change during the first three months of 2006 to the surety bonds that guarantee our performance as it relates to drilling contracts, insurance, tax and other obligations in various jurisdictions.

Dividend Policy

It has been our policy since the IPO not to pay dividends but to instead reinvest earnings in our business. In addition, our revolving credit facility prohibits the payment of dividends without prior approval of the lenders. Due to favorable market conditions, our unrestricted cash balances grew to levels that exceeded our foreseeable needs for cash held for reinvestment and unknown contingencies. Therefore, after securing the approval of our lenders, our board of directors declared a special cash dividend of $1.00 per share that was paid August 25, 2005. A total of $61.2 million was paid in common stock dividends. Our board of directors will determine any change in our dividend policy, the payment of future dividends on our common stock, if any, and the amount of any dividends.

In connection with the special cash dividend and as contemplated by our long term incentive plans, our Executive Compensation Committee awarded special cash bonuses to holders of stock options under our long term incentive plans in the aggregate amount of $0.7 million to compensate them for any potential loss in option value. These bonuses were paid in the third quarter of 2005.

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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 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,

- future utilization rates,
- future dayrates, and
- expectations regarding improvements 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,

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forecast,

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, 2005, 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, 2005.

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

As of March 31, 2006, 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, 2005. There were no material developments in these previously reported matters during the quarter ended March 31, 2006. The Company and its subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of business. The Company does not believe that ultimate liability, if any, resulting from any such other pending litigation will have a material adverse effect on its consolidated results of operations, financial position or cash flows.

Item 6. ***Exhibits***

Exhibit Index

Exhibit No.	Description	Filed Herewith or Incorporated by Reference from:
3.1	Third Amended and Restated Certificate of Incorporation.	Exhibit 3.1 to Annual Report on Form 10-K for the year ended December 31, 2003
3.2	Amended and Restated By-Laws	Exhibit 3.2 to Annual Report on Form 10- K for the year ended December 31, 2003
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
10.1	Form of Employee Deferred Performance Unit Award Letter under the TODCO 2005 Long Term Incentive Plan	Exhibit 10.2 to Current Report on Form 8-K dated as of February 10, 2006
10.2	Form of Employee Performance Bonus Award Letter under the TODCO 2005 Long Term Incentive Plan	Exhibit 10.3 to Current Report on Form 8-K dated as of February 10, 2006
10.3	Form of Employee Restricted Stock Award Letter under the TODCO 2005 Long Term Incentive Plan	Exhibit 10.1 to Current Report on Form 8-K dated as of March 24, 2006
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
32.1	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer	Furnished herewith

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 4, 2006

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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
32.1	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer	Furnished herewith

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