PIONEER DRILLING CO
Form 10-Q
August 05, 2008

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended March 31, 2008

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 1-8182

PIONEER DRILLING COMPANY

(Exact name of registrant as specified in its charter)

TEXAS	74-2088619
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1250 N.E. Loop 410, Suite 1000, San Antonio, Texas	78209
(Address of principal executive offices)	(Zip Code)

210-828-7689

(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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of July 18, 2008, there were 49,788,978 shares of common stock, par value $0.10 per share, of the registrant issued and outstanding.

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PART I. FINANCIAL INFORMATION

ITEM I. FINANCIAL STATEMENTS

PIONEER DRILLING COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2008 (unaudited)	December 31, 2007 (audited)
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,618	$ 76,703
Receivables:		
Trade, net	68,151	46,759
Contract drilling in progress	16,603	7,861
Income tax receivable	340	611
Deferred income taxes	5,334	3,670
Inventory	2,813	1,180
Prepaid expenses and other	6,022	5,073
Total current assets	114,881	141,857
Property and equipment, at cost	743,863	578,697
Less accumulated depreciation and amortization	173,551	161,675
Net property and equipment	570,312	417,022
Deferred income taxes	708	573
Goodwill	172,228	
Intangibles and other long term assets	43,140	760
Total assets	$ 901,269	$ 560,212
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 24,888	$ 21,424
Current portion of long-term debt	23,457	
Income taxes payable	4,371	
Prepaid drilling contracts	3,082	1,933
Accrued expenses:		
Payroll and related employee costs	12,533	5,172
Insurance premiums and deductibles	16,144	9,548
Other	3,463	3,973
Total current liabilities	87,938	42,050
Long-term debt, less current portion	271,563	

Other liabilities	5,087	254
Deferred income taxes	51,430	46,836
Total liabilities	416,018	89,140
Commitments and contingencies		
Shareholders equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding		
Common stock $.10 par value; 100,000,000 shares authorized; 49,788,978 shares and 49,650,978 shares issued and outstanding at March 31, 2008 and December 31, 2007, respectively	4,979	4,965
Additional paid-in capital	298,189	294,922
Accumulated other comprehensive loss	(950)	
Accumulated earnings	183,033	171,185
Total shareholders equity	485,251	471,072
Total liabilities and shareholders equity	$ 901,269	$ 560,212

See accompanying notes to condensed consolidated financial statements.

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PIONEER DRILLING COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(In thousands, except per share data)	
Revenues	$ 113,397	$ 103,347
Costs and expenses:		
Operating costs	70,426	59,189
Depreciation and amortization	17,119	14,736
Selling, general and administrative	7,722	3,824
Bad debt expense	135	
Total operating costs and expenses	95,402	77,749
Income from operations	17,995	25,598
Other income (expense):		
Interest expense	(1,574)	
Interest income	585	881
Other	1,092	8
Total other income	103	889
Income before income taxes	18,098	26,487
Income tax expense	(6,250)	(9,269)
Net earnings	$ 11,848	$ 17,218
Earnings per common share Basic	$ 0.24	$ 0.35
Earnings per common share Diluted	$ 0.24	$ 0.34
Weighted average number of shares outstanding Basic	49,759	49,619
Weighted average number of shares outstanding Diluted	50,291	50,127

See accompanying notes to condensed consolidated financial statements.

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PIONEER DRILLING COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2008	2007
	(In thousands)	
Cash flows from operating activities:		
Net earnings	$ 11,848	$ 17,218
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation and amortization	17,119	14,736
Allowance for doubtful accounts	135	
Loss (gain) on dispositions of property and equipment	(23)	576
Stock-based compensation expense	951	587
Deferred income taxes	554	6,179
Change in other assets	74	5
Change in non-current liabilities	(88)	(85)
Changes in current assets and liabilities:		
Receivables	(7,023)	2,149
Inventory	(259)	
Prepaid expenses and other	491	374
Accounts payable	132	(3,170)
Income tax payable	4,780	(3,791)
Prepaid drilling contracts	1,150	
Accrued expenses	10,144	1,677
Net cash provided by operating activities	39,985	36,455
Cash flows from investing activities:		
Acquisition of production services business of WEDGE	(313,610)	
Acquisition of production services business of Competition	(26,101)	
Purchases of property and equipment	(32,938)	(27,870)
Purchase of auction rate preferred securities	(16,475)	
Proceeds from sale of property and equipment	933	1,477
Net cash used in investing activities	(388,191)	(26,393)
Cash flows from financing activities:		
Payments of debt	(22,001)	
Proceeds from issuance of debt	311,500	
Debt issuance costs	(3,281)	
Proceeds from exercise of options	653	110
Excess tax benefit of stock option exercises	250	19
Net cash provided by financing activities	287,121	129
Net increase (decrease) in cash and cash equivalents	(61,085)	10,191

Beginning cash and cash equivalents		76,703		74,754
Ending cash and cash equivalents	$	15,618	$	84,945
Supplementary disclosure:				
Interest paid	$	1,489	$	11
Income tax paid	$	1	$	

See accompanying notes to condensed consolidated financial statements.

PIONEER DRILLING COMPANY AND SUBSIDARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations and Summary of Significant Accounting Policies

Business and Basis of Presentation

Pioneer Drilling Company and subsidiaries provide drilling and production services to our customers in select oil and natural gas exploration and production regions in the United States and Colombia. Our Drilling Services Division provides contract land drilling services with its fleet of 69 drilling rigs, 17 of which are operating in South Texas, 21 of which are operating in East Texas, 9 of which are operating in North Texas, 6 of which are operating in Western Oklahoma, 11 of which are operating in the Rocky Mountain region and 3 of which are operating internationally in Colombia. In addition, we deployed a 1000 horsepower rig to Colombia that we expect to begin operating in August 2008 and we are currently marketing a 1500 horsepower rig that we plan to deploy for further expansion into international markets. We are currently constructing a 1500 horsepower drilling rig that we expect to be completed and available for operation in the United States in December 2008. Our Production Services Division provides well services, wireline services and fishing and rental services with its fleet of 66 workover rigs, 51 wireline units and approximately $14 million of fishing and rental tools equipment through our facilities in Texas, Kansas, North Dakota, Colorado, Montana, Utah and Oklahoma.

The accompanying consolidated financial statements include the accounts of Pioneer Drilling Company and its wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. In December 2007, our Board of Directors approved a change in our fiscal year end from March 31st to December 31st. The fiscal year end change was effective December 31, 2007 and resulted in a nine month reporting period from April 1, 2007 to December 31, 2007. We implemented the fiscal year end change to align our United States reporting period with the required Colombian statutory reporting period as well as the reporting periods of peer companies in the industry.

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of our management, all adjustments (consisting of normal, recurring accruals) necessary for a fair presentation have been included. In preparing the accompanying unaudited condensed consolidated financial statements, we make various estimates and assumptions that affect the amounts of assets and liabilities we report as of the dates of the balance sheets and income and expenses we report for the periods shown in the income statements and statements of cash flows. Our actual results could differ significantly from those estimates. Material estimates that are particularly susceptible to significant changes in the near term relate to our recognition of revenues and costs for turnkey contracts, our estimate of the allowance for doubtful accounts, our estimate of the self-insurance portion of our health and workers compensation insurance, our estimate of asset impairments, our estimate of deferred taxes and our determination of depreciation and amortization expense. The condensed consolidated balance sheet as of December 31, 2007 has been derived from our audited financial statements. We suggest that you read these condensed consolidated financial statements together with the consolidated financial statements and the related notes included in our transition report on Form 10-KT for the fiscal year ended December 31, 2007.

Drilling Contracts

Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used and the anticipated duration of the work to be performed. Generally, our contracts provide for the drilling of a single well and typically permit the customer to terminate on short notice. However, we have entered into more longer-term drilling contracts during periods of high rig demand. In addition, when we construct new drilling rigs, we have entered into longer-term drilling contracts. As of July 18, 2008, we had 22 contracts with terms of 6 months to 3 years in duration, of which 12 will expire by January 18, 2009, 6 have a remaining term of 6 to 12 months, 1 has a remaining term of 12 to 18 months and 3 have a remaining term in excess of 18 months.

Foreign Currencies

Our functional currency for our foreign subsidiary in Colombia is the U.S. dollar. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. Gains and losses from remeasurement of foreign currency financial statements into U.S. dollars and from foreign currency transactions are included in other income or expense.

Revenue and Cost Recognition

Drilling Services We earn revenues by drilling oil and gas wells for our customers under daywork, turnkey or footage contracts, which usually provide for the drilling of a single well. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey and footage contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the contract term of certain drilling contracts. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs.

The asset contract drilling in progress represents revenues we have recognized in excess of amounts billed on contracts in progress. The asset prepaid expenses and other includes deferred mobilization costs for certain drilling contracts. The liability prepaid drilling contracts represents deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized.

Production Services We earn revenues for well services, wireline services and fishing and rental services based on purchase orders, contracts or other persuasive evidence of an arrangement with the customer, such as master service agreements, that include fixed or determinable prices. These production services revenues are recognized when the services have been rendered and collectability is reasonably assured.

Restricted Cash

As of March 31, 2008, we had restricted cash in the amount of $3,250,000 held in an escrow account to be used for future payments in connection with the acquisition of Prairie Investors d/b/a Competition Wireline (Competition). The former owner of Competition will receive annual installments of $650,000 payable over a 5 year term from the escrow account. Restricted cash of $650,000 and $2,600,000 is recorded in other current assets and other long term assets, respectively. The associated obligation of $650,000 and $2,600,000 is recorded in accrued expenses and other long-term liabilities, respectively.

Trade Accounts Receivable

We record trade accounts receivable at the amount we invoice our customers. These accounts do not bear interest. The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our accounts receivable as of the balance sheet date. We determine the allowance based on the credit worthiness of our customers and general economic conditions. Consequently, an adverse change in those factors could affect our estimate of our allowance for doubtful accounts. We review our allowance for doubtful accounts monthly. Balances more than 90 days past due are reviewed individually for collectability. We charge off account balances against the allowance after we have exhausted all reasonable means of collection and determined that the potential for recovery is remote. We do not have any off-balance sheet credit exposure related to our customers. We had an allowance for doubtful accounts of $0.3 million at March 31, 2008 and no allowance for doubtful accounts at December 31, 2007.

Investments

Intangibles and other long-term assets include investments in tax exempt, auction rate preferred securities (ARPSs). Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of March 31, 2008 because of our inability to determine the recovery period of our investment in ARPSs.

At March 31, 2008, we held $16.5 million (par value) of investments comprised of ARPSs, which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through Dutch auctions that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds, backed by assets that are equal to or greater than 200% of the liquidation preference and guaranteed by monoline bond insurance companies. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several failed auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. We may not be able to access the funds we invested in our ARPSs without a loss of principal, unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately be able to liquidate our investments without material loss primarily due to the collateral securing the ARPSs. We do not currently intend to attempt to sell our ARPSs since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility.

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Our ARPSs are reported at amounts that reflect our estimate of fair value. Statement of Financial Accounting Standards (SFAS) SFAS No. 157, *Fair Value Measurement,* provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value. To estimate the fair values of our ARPSs, we used inputs defined by SFAS 157 as level 3 inputs which are unobservable for the asset or liability and are developed based on the best information available in the circumstances, which might include the company s own data. We estimate the fair value of our ARPSs based on discounted cash flow models and secondary market comparisons of similar securities.

Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders equity. The estimated fair value of our ARPSs at March 31, 2008 was $15.0 million compared with a par value of $16.5 million. The $1.5 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and is recorded as an unrealized loss. We would recognize an impairment charge if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary.

Inventories

Inventories primarily consist of drilling rig replacement parts and supplies held for use by our Drilling Services Division s operations and supplies held for use by our Production Services Division s operations. Inventories are valued at the lower of cost (first in, first out or actual) or market value.

Property and Equipment

Property and equipment are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated useful lives of the assets using the straight-line method. We record the same depreciation expense whether a rig is idle or working. We charge our expenses for maintenance and repairs to operating costs. We charge our expenses for renewals and betterments to the appropriate property and equipment accounts.

We review our long-lived assets and intangible assets for impairment whenever events or circumstances provide evidence that suggests that we may not recover the carrying amounts of any of these assets. In performing the review for recoverability, we estimate the future net cash flows we expect to obtain from the use of each asset and its eventual disposition. If the sum of these estimated future undiscounted net cash flows is less than the carrying amount of the asset, we recognize an impairment loss.

Effective January 1, 2008, management reassessed the estimated useful lives assigned to a group of 19 drilling rigs that were recently constructed. These drilling rigs were constructed with new components that have longer estimated useful lives when compared to other drilling rigs that are equipped with older components. As a result, we increased the estimated useful lives for this group of recently constructed drilling rigs from an average useful life of 9 years to 12 years. The following table provides the impact of this change in depreciation and amortization expense for the three months ended March 31, 2008 (amounts in thousands):

	Three Months Ended March 31, 2008	
Depreciation and amortization expense using prior useful lives	$	18,063
Impact of change in estimated useful lives		(944)
Depreciation and amortization expense, as reported	$	17,119
Diluted earnings per common share using prior useful lives	$	0.22
Impact of change in estimated useful lives		0.02
Diluted earnings per common share, as reported	$	0.24

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As of March 31, 2008, the estimated useful lives of our asset classes are as follows:

	Lives
Drilling rigs and equipment	3 - 25
Workover rigs and equipment	5 - 20
Wireline units and equipment	5 - 10
Fishing and rental tools equipment	7
Vehicles	5 - 10
Office equipment	3 - 5
Buildings and improvements	3 - 40

Goodwill and Other Intangible Assets

Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. We account for goodwill and other intangible assets under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Goodwill and other intangible assets not subject to amortization are tested for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. SFAS No. 142 requires a two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit s goodwill is determined by allocating the unit s fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value.

Our major classes of intangible assets subject to amortization under SFAS No. 142 consist of customer lists, trade names and non-compete agreements. Amortization expense for our non-compete agreements is calculated using the straight-line method over the period of the agreement or the estimated economic useful live of the intangible asset which ranges from 1 to 10 years.

Income Taxes

Pursuant to SFAS No. 109, Accounting for Income Taxes, we follow the asset and liability method of accounting for income taxes, under which we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. We measure our deferred tax assets and liabilities by using the enacted tax rates we expect to apply to taxable income in the years in which we expect to recover or settle those temporary differences. Under SFAS No. 109, we reflect in income the effect of a change in tax rates on deferred tax assets and liabilities in the period during which the change occurs.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive loss. Other comprehensive loss includes the change in the fair value of our ARPSs, net of tax, for the quarter ended March 31, 2008. We had no other comprehensive income (loss) for the quarter ended March 31, 2007. The following table sets forth the components of comprehensive income (amounts in thousands):

	Three Months Ended March 31,	
	2008	2007
Net income	$ 11,848	$ 17,218
Other comprehensive loss unrealized loss on securities	(950)	
Comprehensive income	$ 10,898	$ 17,218

Stock-based Compensation

Effective April 1, 2006, we adopted SFAS No. 123 (Revised), *Share-Based Payment,* utilizing the modified prospective approach. Prior to the adoption of SFAS 123R, we accounted for stock option grants in accordance with the intrinsic-value-based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* and related interpretations, as permitted by SFAS No. 123, *Accounting for Stock-Based Compensation.* Accordingly, we recognized no compensation expense for stock options granted, as all stock options were granted at an exercise price equal to the closing market value of the underlying common stock on the date of grant. Under the modified prospective approach, compensation cost for the three months ended March 31, 2008 includes compensation cost for all stock options granted prior to, but not yet vested as of, April 1, 2006, based on the grant-date fair value estimated in accordance with SFAS 123, and compensation cost for all stock options granted

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subsequent to April 1, 2006, based on the grant-date fair value estimated in accordance with SFAS 123R. We use the graded vesting method for recognizing compensation costs for stock options. Compensation costs of approximately $735,000 and $215,000 for stock options were recognized in selling, general and administrative expense and operating costs, respectively, for the three months ended March 31, 2008.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the options are sold over the exercise price of the options. In accordance with SFAS 123R, we reported all excess tax benefits resulting from the exercise of stock options as financing cash flows in our consolidated statement of cash flows. There were 138,000 stock options exercised during the three months ended March 31, 2008.

We estimate the fair value of each option grant on the date of grant using a Black-Scholes options-pricing model. The following table summarizes the assumptions used in the Black-Scholes option-pricing model for the three months ended March 31, 2008. There were no options granted during the three months ended March 31, 2007. There were 345,000 options granted during the three months ended March 31, 2008:

	Three Months Ended March 31, 2008
Weighted average expected volatility	43%
Weighted-average risk-free interest rates	2.0%
Weighted-average expected life in years	3.75
Options granted	345,000
Weighted-average grant-date fair value	$ 4.73

The assumptions above are based on multiple factors, including historical exercise patterns of homogeneous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for these same homogeneous groups and volatility of our stock price. As we have not declared dividends since we became a public company, we did not use a dividend yield. In each case, the actual value that will be realized, if any, will depend on the future performance of our common stock and overall stock market conditions. There is no assurance the value an optionee actually realizes will be at or near the value we have estimated using the Black-Scholes options-pricing model.

Related-Party Transactions

Our Chief Executive Officer, President of Drilling Services Division, Senior Vice President of Drilling Services Division Marketing, and a Vice President of Drilling Services Division - Operations occasionally acquire a 1% to 5% minority working interest in oil and gas wells that we drill for 1 of our customers. These individuals acquired a minority working interest in 1 well that we drilled for this customer during the three months ended March 31, 2007. We recognized contract drilling revenues of $280,000 on this well during the three months ended March 31, 2007. These individuals did not acquire a minority working interest in any wells that we drilled for this customer during the three months ended March 31, 2008.

In connection with the acquisitions of the production services businesses from WEDGE Group Incorporated (WEDGE) and Competition on March 1, 2008, we have leases for various operating and office facilities with entities that are owned by former WEDGE employees and Competition employees that are now employees of our company. Rent expense for the quarter ended March 31, 2008 was approximately $45,000 for these related party leases. In addition, we have non-compete agreements with several former WEDGE employees that are now employees of our company. These non-compete agreements are recorded as intangible assets with a cost, net of accumulated amortization, of $1.8 million as of March 31, 2008. See note 2 for further information regarding the acquisitions.

We purchased goods and services during the quarter ended March 31, 2008 from 2 vendors that are owned by employees of our company. We purchased $46,000 of well servicing equipment from 1 related party vendor and $18,000 of catering services from the other related party vendor for the quarter ended March 31, 2008.

Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosure of fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements and, accordingly, does not require any new fair value measurements. SFAS No. 157, as issued, was effective for financial statement issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. However, on February 12, 2008, the FASB issued FSP FAS No. 157-2, *Effective Dates of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations and financial condition.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 159 did not have a material impact on our financial position or results of operations and financial condition.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an Amendment of ARB No. 51*. This statement establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 clarifies that a non-controlling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS No. 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the non-controlling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the non-controlling interest. SFAS No.160 is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption to have a material impact on our financial position or results of operations and financial condition.

In December 2007, the FASB issued SFAS No. 141R (revised 2007) which replaces SFAS No. 141, *Business Combinations* (SFAS No. 141R). SFAS No. 141R applies to all transactions and other events in which one entity obtains control over one or more other businesses. SFAS No. 141R requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. This fair value approach replaces the cost-allocation process required under SFAS No. 141 whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. SFAS No. 141R requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. Under SFAS No.141R, the requirements of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the recognition criteria of SFAS No. 5, *Accounting for Contingencies*. SFAS No. 141R is expected to have a significant impact on our accounting for business combinations closing on or after January 1, 2009.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS No. 161). SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The guidance in SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The Company is currently assessing the impact of SFAS No. 161. We do not have any derivative instruments and expect the adoption of SFAS No. 161 to have no impact on our financial position or results of operations and financial condition.

Reclassification

Certain amounts in the financial statements for the prior years have been reclassified to conform to the current year s presentation.

2. Acquisitions

On March 1, 2008, we acquired the production services business from WEDGE which provided well services, wireline services and fishing and rental services with a fleet of 62 workover rigs, 45 wireline units and approximately $13 million of fishing and rental tools equipment through its facilities in Texas, Kansas, North Dakota, Colorado, Utah and Oklahoma. The aggregate purchase price for the acquisition was approximately $314.8 million, which consisted of assets acquired of $329.1 million and liabilities assumed of $14.3 million. The aggregate purchase price includes $3.4 million of costs incurred to acquire the production services business from WEDGE. We financed the acquisition with approximately $3.3 million of cash on hand and $311.5 million of debt incurred under our senior secured revolving credit facility described in Note 3.

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The following table summarizes the allocation of the purchase price and related acquisition costs to the preliminary estimated fair value of the assets acquired and liabilities assumed as the date of acquisition (amounts in thousands):

Cash acquired	$ 1,168
Other current assets	22,102
Property and equipment	137,173
Intangible asset and other assets	418
Goodwill	168,216
Total assets acquired	$ 329,077
Current liabilities	$ 10,655
Long-term debt	1,462
Other long term liabilities	2,182
Total liabilities assumed	$ 14,299
Net assets acquired	$ 314,778

The following unaudited pro forma consolidated summary financial information gives effect of the acquisition of the production services business from WEDGE as though it was effective as of the beginning of each of the three month periods ended March 31, 2008 and 2007. Pro forma adjustments primarily relate to additional depreciation, amortization and interest costs. The pro forma information reflects our company s historical data and historical data from the acquired production services business from WEDGE for the periods indicated. The pro forma data may not be indicative of the results we would have achieved had we completed the acquisition on January 1, 2007 or 2008, or what we may achieve in the future and should be read in conjunction with the accompanying historical financial statements.

	Pro Forma Three Months Ended March 31,	
	2008	2007
	(in thousands, except per share data)	
Total revenues	$ 137,048	$ 125,842
Net earnings	$ 14,140	$ 17,853
Earnings per common share		
Basic	$ 0.28	$ 0.36
Diluted	$ 0.28	$ 0.36

On March 1, 2008, immediately following the acquisition of the production services business from WEDGE, we acquired the production services business from Competition which provided wireline services with a fleet of 6 wireline units through its facilities in Montana. The aggregate purchase price for the Competition acquisition was approximately $30.0 million, which consisted of assets acquired of $30.1 million and liabilities assumed of $0.1 million. The aggregate purchase price includes $0.4 million of costs incurred to acquire the production services business from Competition. We financed the acquisition with $26.1 million cash on hand, a note payable due to the owner for $3.3 million and $0.6 million of current payables due to the owner. Goodwill of $4.0 million and intangible assets and other assets of $19.3 million were recorded in connection with the acquisition.

The acquisitions of the production services businesses from both WEDGE and Competition were accounted for as acquisitions of businesses. The purchase price allocations of the purchase prices for the production services businesses are preliminary at this time and may change by a material amount once we receive finalized information regarding the fair value estimates of the assets acquired and liabilities assumed in the acquisition. Goodwill was recognized as part of these acquisitions since the purchase price exceeded the estimated fair value of the assets acquired and liabilities assumed. We believe that the goodwill is related to the acquired workforces, future synergies between our existing Drilling Services Division and our new Production Services Division and the ability to expand our service offerings.

3. Long-term Debt

Long-term debt as of March 31, 2008 consists of the following (amounts in thousands):

Senior secured credit facility	$ 289,500
Subordinated notes payable	5,520
	295,020
Less current portion	(23,457)
	$ 271,563

Senior Secured Revolving Credit Facility

On February 29, 2008, we entered into a credit agreement with Wells Fargo Bank, N.A. and a syndicate of lenders (collectively the Lenders). The credit agreement provides for a senior secured revolving credit facility, with sub-limits for letters of credit and a swing-line facility of up to an aggregate principal amount of $400 million, all of which mature on February 28, 2013. The senior secured revolving credit facility and the obligations thereunder are secured by substantially all our domestic assets and are guaranteed by certain of our domestic subsidiaries. Borrowings under the senior secured revolving credit facility bear interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin is determined based upon our leverage ratio in accordance with a pricing grid in the credit agreement. The per annum margin for LIBOR rate borrowings ranges from 1.50% to 2.50% and for bank prime rate borrowings ranges from 0.50% to 1.50%. Based on the terms in the credit agreement, the LIBOR margin and bank prime rate margin in effect until delivery of the compliance certificate for December 31, 2008 are 2.25% and 1.25%, respectively. A commitment fee is due quarterly based on the average daily unused amount of the commitments of the Lenders under the senior secured revolving credit facility. In addition, a fronting fee is due for each letter of credit issued and a quarterly letter of credit fee is due based on the average undrawn amount of letter of credit outstanding during such period. We may repay the senior secured revolving credit facility balance outstanding in whole or in part at any time without premium or penalty. The senior secured revolving credit facility replaced the $20.0 million credit facility we previously had with Frost National Bank. Borrowings under the senior secured revolving credit facility were used to fund the WEDGE acquisition and are available for future acquisitions, working capital and other general corporate purposes.

Effective June 11, 2008, we entered into a Waiver Agreement with the Lenders to waive the requirement to provide certain financial statements and our compliance certificate within the time period required by the credit agreement. The Waiver Agreement now requires us to provide the financial statements and our compliance certificate on or before August 13, 2008. Until we provide these financial statements and our compliance certificate, the aggregate principal amount outstanding under the credit agreement may not exceed $350 million at any time (provided, however, that the commitment fee will continue to be calculated based on the total commitment of $400 million), and the per annum margin applicable to all amounts outstanding under the credit agreement will increase from the current rate of 2.25% for LIBOR rate borrowings and 1.25% for bank prime rate borrowings to 2.50% for LIBOR rate borrowings and 1.50% for bank prime rate borrowings. The required financial statements and our compliance certificate are being delivered concurrently with the filing of this Quarterly Report on Form 10-Q.

At July 25, 2008, we had $267.5 million outstanding under the revolving portion of the senior secured revolving credit facility and $7.8 million in committed letters of credit. Under the terms of the credit agreement, committed letters of credit are applied against our borrowing capacity under the senior secured revolving credit facility. The borrowing availability under the senior secured revolving credit facility was $74.7 million at July 25, 2008, based on our reduced borrowing limit of $350 million according to the terms of the Waiver Agreement entered into on June 11, 2008. We expect our borrowing limit to return to $400 million upon delivery of the required financial statements to the Lenders concurrently with the filing of this Quarterly Report on Form 10-Q. Principal payments of $22.0 million made after March 31, 2008 are classified in the current portion of long-term debt as of March 31, 2008. The outstanding balance under our senior secured credit facility is not due until maturity on February 28, 2013. However, when cash and working capital is sufficient, we may make principal payments to reduce the outstanding debt balance prior to maturity.

At March 31, 2008, we were in compliance with the covenants contained in the credit agreement which include restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, capital expenditures, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. The credit agreement requires that we meet a maximum consolidated leverage ratio, a minimum interest coverage ratio and, if the leverage ratio is greater than 2.25 to 1.00, a minimum asset coverage ratio. In addition, the credit agreement contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.

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Subordinated Notes Payable

In addition to amounts outstanding under the senior secured revolving credit facility, long-term debt includes subordinated notes payable to certain employees that are former shareholders of the production services businesses that were acquired by WEDGE prior to our acquisition of WEDGE on March 1, 2008 and a subordinated note payable to an employee that is a former shareholder of Competition. These subordinated notes payable have interest rates ranging from 6% to 14%, require quarterly payments of principal and interest and have final maturity dates ranging from January 2009 to March 2013. The aggregate outstanding balance of these subordinated notes payable was $5.5 million as of March 31, 2008.

4. Commitments and Contingencies

In connection with our expansion into international markets, our foreign subsidiaries have obtained bonds for bidding on drilling contracts, performing under drilling contracts, and remitting customs and importation duties. We have guaranteed payments of $28.9 million relating to our performance under these bonds.

In addition, due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers compensation claims and employment-related disputes. Legal costs relating to these matters are expensed as incurred. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition, results of operations or cash flow from operations and there is only a remote possibility that any such matter will require any additional loss accrual.

5. Earnings Per Common Share

The following table presents a reconciliation of the numerators and denominators of the basic earnings per share and diluted earnings per share computations as required by SFAS No. 128 (amounts in thousands, except per share data):

	Three Months Ended March 31,	
	2008	2007
Basic		
Net earnings	$ 11,848	$ 17,218
Weighted average shares	49,759	49,619
Earnings per share	$ 0.24	$ 0.35

	Three Months Ended March 31,	
	2008	2007
Diluted		
Net earnings	$ 11,848	$ 17,218
Weighted average shares:		
Outstanding	49,759	49,619
Diluted effect of stock options	532	508
	50,291	50,127
Earnings per share	$ 0.24	$ 0.34

6. Equity Transactions

Employees and former employees exercised stock options for the purchase of 138,000 shares of common stock during the three months ended March 31, 2008 at prices ranging from $3.70 to $10.31 per share. Employees and former employees exercised stock options for the purchase of 34,000 shares of common stock during the three months ended March 31, 2007 at prices ranging from $3.20 to $4.77 per share.

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7. Segment Information

At March 31, 2008, we had two operating segments referred to as the Drilling Services Division and the Production Services Division which is the basis management uses for making operating decisions and assessing performance. Prior to our acquisitions of the production services businesses from WEDGE and Competition on March 1, 2008, all our operations related to the Drilling Services Division and we reported these operations in a single operating segment. The acquisitions of the production services businesses from WEDGE and Competition resulted in the formation of our Production Services Division. See Note 2.

Drilling Services Division - Our Drilling Services Division provides contract land drilling services with its fleet of 69 drilling rigs, 17 of which were operating in South Texas, 21 of which were operating in East Texas, 9 of which were operating in North Texas, 6 of which were operating in Western Oklahoma, 11 of which were operating in the Rocky Mountain region and 3 of which were operating internationally in Colombia. In addition, we deployed a 1000 horsepower rig to Colombia that we expect to begin operating in August 2008 and we are currently marketing a 1500 horsepower rig that we plan to deploy for further expansion into international markets. We are currently constructing a 1500 horsepower drilling rig that we expect to be completed and available for operation in the United States in December 2008.

Production Services Division Our Production Services Division provides well services, wireline services and fishing and rental services:

Well services are provided with a fleet of 66 rigs (61 550 horsepower rigs, 4 600 horsepower rigs and 1 400 horsepower rig) and pump packages capable of working at depths of 20,000 feet to complete, maintain, and workover oil and natural gas producing wells.

Wireline services provide open and cased-hole wireline services with a fleet of 51 wireline units. Services include radial and standard cement bond logging with gamma-ray-neutron, casing calipers, temperature logging, pipe recovery, bridge plugs and a full range of perforating. In addition, the group operates the latest pulsed-neutron technology in through-casing logs, utilizing a direct, deeper-reading neutron detector.

Fishing and rental services are provided though approximately $14 million of fishing and rental tools equipment, air drilling equipment, power swivels and blowout preventers.

The following table sets forth certain financial information for our two operating segments and corporate for the three months ended March 31, 2008 (amounts in thousands):

	Drilling Services Division	Production Services Division	Corporate	Total
Revenues	$ 100,041	$ 13,356	$	$ 113,397
Operating costs	63,497	6,929		70,426
Segment profits	$ 36,544	$ 6,427	$	$ 42,971
Depreciation and amortization	$ 15,729	$ 1,298	$ 92	$ 17,119
Capital expenditures	$ 24,814	$ 3,139	$	$ 27,953
Identifiable assets	$ 511,866	$ 368,332	$ 21,071	$ 901,269

The following table reconciles the segment profits reported above to income from operations as reported on the condensed consolidated statements of operations for the three months ended March 31, 2008 (amounts in thousands):

Segment profits	$ 42,971
Depreciation and amortization	(17,119)
Selling, general and administrative	(7,722)

Bad debt expense	(135)
Income from operations	$ 17,995

The following table sets forth certain financial information for our international operations in Colombia as of and for the three months ended March 31, 2008 which is included in our Drilling Services Division (amounts in thousands):

Identifiable assets	$97,779
Revenues	$ 8,541

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

Statements we make in the following discussion that express a belief, expectation or intention, as well as those that are not historical fact, are forward-looking statements that are subject to risks, uncertainties and assumptions. Our actual results, performance or achievements, or industry results, could differ materially from those we express in the following discussion as a result of a variety of factors, including general economic and business conditions and industry trends, the continued strength or weakness of the contract land drilling industry in the geographic areas in which we operate, decisions about onshore exploration and development projects to be made by oil and gas companies, the highly competitive nature of our business, difficulty in integrating the services of acquired companies, including the production services businesses of WEDGE and Competition, in an efficient and effective manner, the availability, terms and deployment of capital, the availability of qualified personnel, and changes in, or our failure or inability to comply with, government regulations, including those relating to the environment. We have discussed many of these factors in more detail elsewhere in this report and in our transition report on Form 10-KT for the fiscal year ended December 31, 2007. These factors are not necessarily all the important factors that could affect us. Unpredictable or unknown factors we have not discussed in this report or in our transitional report on Form 10-KT could also have material adverse effects on actual results of matters that are the subject of our forward-looking statements. All forward-looking statements speak only as the date on which they are made and we undertake no duty to update or revise any forward-looking statements. We advise our shareholders that they should (1) be aware that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

Company Overview

Pioneer Drilling Company is a multi-national oilfield services company that provides drilling services and production services to independent and major oil and gas exploration and production companies throughout the United States and internationally in Colombia. Our company was incorporated in 1979 as the successor to a business that had been operating since 1968. Over the years, our business has grown through acquisitions and through organic growth. Since September 1999, we have significantly expanded our drilling rig fleet by adding 42 rigs through acquisitions and by adding 26 rigs through the construction of rigs from new and used components. On March 1, 2008, we significantly expanded our service offerings when we acquired the production services businesses of WEDGE Group Incorporated (WEDGE) and Prairie Investors d/b/a Competition Wireline (Competition) which provide well services, wireline services and fishing and rental services. These drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life at a well site and enable us to meet multiple needs of our customers.

Business Segments

We currently conduct our operations through two operating segments: our Drilling Services Division and our Production Services Division. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 7, *Segment Information,* of the Notes to Condensed Consolidated Financial Statements, included in Part I, Item I, *Financial Statements,* of this Quarterly Report on Form 10Q.

Drilling Services Division Our Drilling Services Division provides contract land drilling services with its fleet of 69 drilling rigs, 17 of which are operating in South Texas, 21 of which are operating in East Texas, 9 of which are operating in North Texas, 6 of which are operating in Western Oklahoma, 11 of which are operating in the Rocky Mountain region and 3 of which are operating internationally in Colombia. In addition, we deployed a 1000 horsepower rig to Colombia that we expect to begin operating in August 2008 and we are currently marketing a 1500 horsepower rig that we plan to deploy for further expansion into international markets. We are currently constructing a 1500 horsepower drilling rig that we expect to be completed and available for operation in the United States in December 2008. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and gas wells either through competitive bidding or through direct negotiations with customers. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used and the anticipated duration of the work to be performed.

Production Services Division Our Production Services Division earns revenues for well services, wireline services and fishing and rental services based on purchase orders, contracts or other persuasive evidence of an arrangement with the customer, such as master service agreements, that include fixed or determinable prices. These production services revenues are recognized when the services have been rendered and collectability is reasonably assured.

- Well services are provided with a fleet of 66 rigs (61 550 horsepower rigs, 4 600 horsepower rigs and 1 400 horsepower rig) with pump packages capable of working at depths of 20,000 feet to complete, maintain, and workover oil and natural gas producing wells.

- o Wireline services provide open and cased-hole wireline services with a fleet of 51 wireline units. Services include radial and standard cement bond logging with gamma-ray-neutron, casing calipers, temperature logging, pipe recovery, bridge plugs and a full range of perforating. In addition, the group operates the latest pulsed-neutron technology in through-casing logs, utilizing a direct, deeper-reading neutron detector.

- o Fishing and rental services are provided though approximately $14 million of fishing and rental tools equipment, air drilling equipment, power swivels and blowout preventers.

Pioneer Drilling Company s corporate office is located at 1250 N.E. Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (210) 828-7689 and our website address is www.pioneerdrlg.com. We make available free of charge though our website our Annual Reports on Form 10K, Quarterly Reports on Form 10-Q, Current Reports on Form 8K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission (the SEC). Information on our website is not incorporated into this report or otherwise made part of this report.

Business Strategy

In past years, our strategy was to become a premier land drilling company through steady and disciplined growth. We executed this strategy by acquiring and building a high quality drilling rig fleet that operates in active drilling markets in the United States. Our long term strategy is to maintain and leverage our position as a leading land drilling company and evolve into a premier multi-service, international oilfield services provider. The key elements of this long term strategy include:

Expand our Operations into International Markets In early 2007, we announced our intention to expand internationally and began negotiating drilling contracts in Colombia. We are currently operating 3 drilling rigs in Colombia, deploying a 1000 horsepower drilling rig that we expect will begin operating in Colombia in August 2008 and marketing a 1500 horsepower drilling rig for further international expansion.

Pursue Opportunities into Other Oilfield Services We strive to mitigate the cyclical risk in oilfield services by complimenting our drilling services with certain production services. Effective March 1, 2008, we acquired the production services businesses of WEDGE and Competition which provide well services, wireline services and fishing and rental services with a fleet of 62 workover rigs, 51 wireline units and approximately $13 million of fishing and rental tools equipment through its facilities in Texas, Kansas, North Dakota, Colorado, Utah, Montana and Oklahoma. These acquisitions resulted in the formation of our Production Services Division operating segment.

Continue Growth with Select Capital Deployment We intend to continue growing our business by making selective acquisitions, continuing new-build programs and / or upgrading our existing assets. Our capital investment decisions are determined by an analysis of the projected return on capital employed on each of those alternatives. Acquisitions and new-build opportunities that support our long term strategy are also evaluated for fit with our current geographic locations and risk assessments are performed. We are currently constructing a 1500 horsepower drilling rig that we expect to be completed and available for operation in the United States in December 2008.

Market Conditions in Our Industry

Demand for oilfield services offered by our industry is a function of our customers willingness to make operating and capital expenditures to explore for, develop and produce hydrocarbons, which in turn is affected by current and expected levels of oil and gas prices. As oil and gas prices have risen, oil and gas companies have generally increased their drilling and workover activities. This increased activity resulted in increased domestic exploration and production spending compared to the prior year of 17% in 2006, according to the Lehman Brothers 2007 E&P Spending Survey. Domestic spending increased 4% in 2007 and is estimated to increase 4% in 2008, according to the Lehman Brothers 2008 E&P Spending Survey. Latin America has experienced even higher exploration and production spending increases during the same time periods.

On July 18, 2008, the spot price for West Texas Intermediate crude oil was $128.88, the spot price for Henry Hub natural gas was $10.54 and the Baker Hughes land rig count was 1,833, a 9% increase from 1,685 on July 20, 2007. The average weekly spot prices of West Texas Intermediate crude oil and Henry Hub natural gas, the average weekly domestic land rig count per the Baker Hughes land rig count, and the average monthly domestic workover rig count for the quarter ended March 31, 2008 and each of the previous five years ended March 31, 2008 were:

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	Three Months Ended March 31, 2008	Years Ended March 31, 2008	2007	2006	2005	2004
Oil (West Texas Intermediate)	$ 97.74	$82.50	$64.96	$59.94	$45.04	$31.47
Natural Gas (Henry Hub)	$ 8.63	$ 7.27	$ 6.53	$ 9.10	$ 5.99	$ 5.27
U.S. Land Rig Count	1,689	1,685	1,589	1,329	1,110	964
U.S. Workover Rig Count	2,463	2,412	2,376	2,271	2,087	1,996

Increased expenditures for exploration and production activities generally leads to increased demand for our drilling services and production services. Rising oil and natural gas prices and the corresponding increase in onshore oil and gas exploration and production spending have led to expanded drilling and well service activity as reflected by the increases in the U.S. land rig counts and U.S. workover rig counts over the previous five years as noted in the table above.

Exploration and production spending is generally categorized as either an operating expenditure or a capital expenditure. Activities designed to add hydrocarbon reserves are classified as capital expenditures, while those associated with maintaining or accelerating production are categorized as operating expenditures.

Capital expenditures by oil and gas companies tend to be relatively sensitive to volatility in oil or gas prices because project decisions are tied to a return on investment spanning a number of years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate in the amount of time required to plan and execute a capital expenditure project (such as the drilling of a deep well). When commodity prices are depressed for even a short period of time, capital expenditure projects are routinely deferred until prices return to an acceptable level.

In contrast, both mandatory and discretionary operating expenditures are substantially more stable than exploration and drilling expenditures. Mandatory operating expenditure projects involve activities that cannot be avoided in the short term, such as regulatory compliance, safety, contractual obligations and projects to maintain the well and related infrastructure in operating condition. Discretionary operating expenditure projects may not be critical to the short-term viability of a lease or field but these projects are relatively insensitive to commodity price volatility. Discretionary operating expenditure work is evaluated according to a simple short-term payout criterion which is far less dependent on commodity price forecasts.

Our business is influenced substantially by both operating and capital expenditures by oil and gas companies. Because existing oil and gas wells require ongoing spending to maintain production, expenditures by oil and gas companies for the maintenance of existing wells are relatively stable and predictable. In contrast, capital expenditures by oil and gas companies for exploration and drilling are more directly influenced by current and expected oil and gas prices and generally reflect the volatility of commodity prices.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal sources of liquidity consist of: (i) cash and cash equivalents (which equaled $15.6 million as of March 31, 2008); (ii) cash generated from operations; and (iii) the unused portion of our senior secured revolving credit facility which has borrowing availability of $74.7 million as of July 25, 2008. The borrowing availability is based on the $350 million borrowing limitation imposed by the June 11, 2008 Waiver Agreement and is adjusted for letters of credit outstanding and subject to certain debt and leverage ratio covenants. Our principal liquidity requirements have been for working capital needs, capital expenditures and acquisitions.

On February 29, 2008, we entered into a credit agreement with Wells Fargo Bank, N.A. and a syndicate of lenders (collectively the Lenders). The credit agreement provides for a senior secured revolving credit facility, with sub-limits for letters of credit and a swing-line facility of up to an aggregate principal amount of $400 million, all of which mature on February 28, 2013. The senior secured revolving credit facility and the obligations thereunder are secured by substantially all our domestic assets and are guaranteed by certain of our domestic subsidiaries. Borrowings under the senior secured revolving credit facility bear interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin is determined based upon our leverage ratio in accordance with a pricing grid in the credit agreement. The per annum margin for LIBOR rate borrowings ranges from 1.50% to 2.50% and for bank prime rate borrowings ranges from 0.50% to 1.50%. Based on the terms in the credit agreement, the LIBOR margin and bank prime rate margin in effect until delivery of the compliance certificate for December 31, 2008 are 2.25% and 1.25%, respectively. A commitment fee is due quarterly based on the average daily unused amount of the commitments of the Lenders under the senior secured revolving credit facility. In addition, a fronting fee is due for each letter of credit issued and a quarterly letter of credit fee is due based on the average undrawn amount of letter of credit outstanding during such period. We may repay the senior secured revolving credit facility balance outstanding in whole or in part at any time without premium or penalty. The senior secured revolving credit facility replaced the $20.0 million credit facility we previously had with Frost National Bank. Borrowings under the senior secured revolving credit facility were used to fund the WEDGE acquisition and are available for future acquisitions, working capital and other general corporate purposes.

Effective June 11, 2008, we entered into a Waiver Agreement with the Lenders to waive the requirement to provide certain financial statements and our compliance certificate within the time period required by the credit agreement. The Waiver Agreement now requires us to provide the financial statements and our compliance certificate on or before August 13, 2008. Until we provide these financial statements and our compliance certificate, the aggregate principal amount outstanding under the credit agreement may not exceed $350 million at any time (provided, however, that the commitment fee will continue to be calculated based on the total commitment of $400 million), and the per annum margin applicable to all amounts outstanding under the credit agreement will increase from the current rate of 2.25% for LIBOR rate borrowings and 1.25% for bank prime rate borrowings to 2.50% for LIBOR rate borrowings and 1.50% for bank prime rate borrowings. The required financial statements and our compliance certificate are being delivered concurrently with the filing of this Quarterly Report on Form 10-Q.

At July 25, 2008, we had $267.5 million outstanding under the revolving portion of the senior secured revolving credit facility and $7.8 million in committed letters of credit. Under the terms of the credit agreement, committed letters of credit are applied against our borrowing capacity under the senior secured revolving credit facility. The borrowing availability under the senior secured revolving credit facility was $74.7 million at July 25, 2008, based on our reduced borrowing limit of $350 million according to the terms of the Waiver Agreement entered into on June 11, 2008. We expect our borrowing limit to return to $400 million upon delivery of the required financial statements to the Lenders concurrently with the filing of this Quarterly Report on Form 10-Q. Principal payments of $22.0 million made after March 31, 2008 are classified in the current portion of long-term debt as of March 31, 2008. The outstanding balance under our senior secured credit facility is not due until maturity on February 28, 2013. However, when cash and working capital is sufficient, we may make principal payments to reduce the outstanding debt balance prior to maturity.

At March 31, 2008, we held $16.5 million (par value) of investments comprised of tax exempt, auction rate preferred securities (ARPSs), which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through Dutch auctions that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds, backed by assets that are equal to or greater than 200% of the liquidation preference and guaranteed by monoline bond insurance companies. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several failed auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. We may not be able to access the funds we invested in our ARPSs without a loss of principal, unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately be able to liquidate our investments without material loss primarily due to the collateral securing the ARPSs. We do not currently intend to attempt to sell our ARPSs since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of March 31, 2008 because of our inability to determine the recovery period of our investment in ARPSs. Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders equity. The estimated fair value of our ARPSs at March 31, 2008 was

$15.0 million compared with a par value of $16.5 million. The $1.5 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and is recorded as an unrealized loss. We would recognize an impairment charge if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary.

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Uses of Capital Resources

On March 1, 2008, we acquired the production services business of WEDGE which provides well services, wireline services and fishing and rental services with a fleet of 62 workover rigs, 45 wireline units and approximately $13 million of fishing and rental tools equipment through facilities in Texas, Kansas, North Dakota, Colorado, Montana, Utah and Oklahoma. The aggregate purchase price for the acquisition was approximately $314.8 million, which consisted of assets acquired of $329.1 million and liabilities assumed of $14.3 million. The aggregate purchase price included $3.4 million of costs incurred to acquire the production services business from WEDGE. We financed the acquisition with approximately $3.3 million of cash on hand and $311.5 million of debt incurred under our new $400 million senior secured revolving credit facility.

On March 1, 2008, immediately following the acquisition of the production services business from WEDGE, we acquired the production services business from Competition which provided wireline services with a fleet of 6 wireline units through its facilities in Montana. The aggregate purchase price for the Competition acquisition was approximately $30.0 million, which consisted of assets acquired of $30.1 million and liabilities assumed of $0.1 million. The aggregate purchase price includes $0.4 million of costs incurred to acquire the production services business from Competition. We financed the acquisition with $26.1 million cash on hand, a note payable due to the owner for $3.3 million and $0.6 million of current payables due to the owner.

For the three months ended March 31, 2008, we had $28.0 million of additions to our property and equipment. For the remainder of fiscal year 2008, we project capital expenditures to be approximately $115.3 million, comprised of new rig and equipment acquisitions of approximately $56.0 million, routine capital expenditures of approximately $30.7 million, and non-routine capital expenditures of approximately $28.6 million. We expect to fund these capital expenditures primarily from operating cash flow in excess of our working capital and other normal cash flow requirements and availability under our senior secured revolving credit facility.

Working Capital

Our working capital was $26.9 million at March 31, 2008, compared to $99.8 million at December 31, 2007. Our current ratio, which we calculate by dividing our current assets by our current liabilities, was 1.3 at March 31, 2008 compared to 3.4 at December 31, 2007.

Our operations have historically generated cash flows sufficient to at least meet our requirements for debt service and normal capital expenditures. However, during periods when higher percentages of our drilling contracts are turnkey and footage contracts, our short-term working capital needs could increase.

The changes in the components of our working capital were as follows:

	March 31, 2008	December 31, 2007	Change
		(In thousands)	
Cash and cash equivalents	$ 15,618	$ 76,703	$ (61,085)
Trade receivables, net	68,151	46,759	21,392
Contract drilling in progress	16,603	7,861	8,742
Income tax receivable	340	611	(271)
Deferred income taxes	5,334	3,670	1,664
Inventory	2,813	1,180	1,633
Prepaid expenses and other	6,022	5,073	949
Current assets	114,881	141,857	(26,976)
Accounts payable	24,888	21,424	3,464
Current portion of long-term debt	23,457		23,457
Prepaid drilling contracts	3,082	1,933	1,149

Income taxes payable	4,371		4,371
Accrued payroll and related employee costs	12,533	5,172	7,361
Accrued insurance premiums and deductibles	16,144	9,548	6,596
Other accrued expenses	3,463	3,973	(510)
Current liabilities	87,938	42,050	45,888
Working capital	$ 26,943	$ 99,807	$ (72,864)

The decrease in cash and cash equivalents was primarily due to our use of $29.4 million of cash to fund the WEDGE and Competition acquisitions, $32.9 million for certain property and equipment expenditures and $16.5 million used to purchase ARPSs in January 2008 that are recorded as other long term assets as of March 31, 2008.

The increase in our receivables at March 31, 2008 as compared to December 31, 2007 was primarily due to receivables of $21.1 million at March 31, 2008 that relate to our new Production Services Division that was formed when we acquired the production services businesses of WEDGE and Competition on March 1, 2008.

The increase in contract drilling in progress at March 31, 2008 as compared to December 31, 2007 was primarily due to drilling revenues that were earned but not billed as of March 31, 2008 for two of our drilling contracts in Colombia.

The increase in inventory at March 31, 2008 as compared to December 31, 2007 was primarily due to inventory of $1.4 million for our new Production Services Division and an increase of $0.3 million of inventory primarily related to our third drilling rig that began operating in Colombia in February 2008. We maintain inventories of replacement parts and supplies for our drilling rigs operating in Colombia to ensure efficient operations in geographically remote areas.

Most of our prepaid expenses and other consist of prepaid insurance and deferred mobilization costs. The increase at March 31, 2008 as compared to December 31, 2007 is primarily due to prepaid expenses and other of $1.2 million for our new Production Services Division and an increase of $1.1 million in deferred mobilization costs relating to our third drilling contract in Colombia that began in February 2008. This increase in prepaid expenses and other was partially offset by a decrease in prepaid insurance. We renew and pay most of our insurance premiums in late October of each year and some in April of each year. As of March 31, 2008, we had amortization of 5 months of these October insurance premiums, as compared to 2 months of amortization as of December 31, 2007.

The increase in accounts payable at March 31, 2008 as compared to December 31, 2007 was primarily due to accounts payable of $4.9 million for our new Production Services Division. The increase in accounts payable was partially offset by a decrease in accounts payable due to a 3% decrease in revenue days for our Drilling Services Division.

The increase in the current portion of long-term debt at March 31, 2008 is primarily due to principal payments of $22.0 million that were made after March 31, 2008 to reduce the outstanding balance of our senior secured revolving credit facility. The outstanding balance under our senior secured credit facility is not due until maturity on February 28, 2013. However, when cash and working capital is sufficient, we may make principal payments to reduce the outstanding debt balance prior to maturity.

The increase in prepaid drilling contracts as of March 31, 2008, as compared to December 31, 2007, was due to amounts billed for mobilization revenues in excess of revenue recognized for our third drilling contract in Colombia that began in February 2008. Mobilization billings, and costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contract.

The increase in accrued payroll and related employee costs was primarily due to an increase in the number of employees and an increase in the number of payroll days accrued at March 31, 2008 as compared to December 31, 2007. In addition, accrued payroll and related employee costs increased due to accrued bonuses related to the 12 month period ended March 31, 2008 that are expected to be paid to certain employees during the third quarter of 2008.

The increase in accrued insurance premiums and deductibles was primarily due to increases in costs incurred for the self-insurance portion of our health and workers compensation insurance during the quarter ended March 31, 2008 as compared to December 31, 2007.

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Long Term Debt

Long-term debt as of March 31, 2008 consists of the following (amounts in thousands):

Senior secured credit facility	$ 289,500
Subordinated notes payable	5,520
	295,020
Less current portion	(23,457)
	$ 271,563

Contractual Obligations

The following table includes all our contractual obligations of the types specified below at March 31, 2008 (amounts in thousands):

		Payments Due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt	$ 295,020	$ 23,457	$ 2,763	$ 268,800	$
Interest on long term debt	64,286	13,854	25,927	24,505	
Purchase commitments	14,429	14,429			
Operating leases	5,101	1,387	2,142	1,304	268
Restricted cash obligations	3,250	650	1,300	1,300	
Other	491	246	245		
Total	$ 382,577	$ 54,023	$ 32,377	$ 295,909	$ 268

Long-term debt consists of $289.5 million outstanding under our senior secured credit facility and $5.5 million outstanding under subordinated notes payable to certain employees that are former shareholders of previously acquired production services businesses. The outstanding balance under our senior secured credit facility is not due until maturity on February 28, 2013, but principal payments of $22.0 million made after March 31, 2008 are classified in the current portion of long-term debt as of March 31, 2008. We may make principal payments to reduce the outstanding debt balance prior to maturity when cash and working capital is sufficient.

Interest payment obligations on our senior secured credit facility are estimated based on (1) interest rates that are in effect under the Waiver Agreement through August 5, 2008, the date we anticipate delivering the financial statements required under the Waiver Agreement, (2) interest rates that we expect to be in effect after we deliver the required financial statements to the Lenders, (3) $22.0 million of principal payments that have been made after March 31, 2008 to reduce the outstanding principal balance, and (4) the remaining principal balance of $267.5 million to be paid at maturity in February 2013. Interest payment obligations on our subordinated notes payable are based on interest rates ranging from 6% to 14%, with quarterly payments of principal and interest and final maturity dates ranging from January 2009 to March 2013.

Purchase obligations primarily relate to drilling rig and well servicing rig upgrades, acquisitions or new construction.

Operating leases consist of lease agreements with terms in excess of 1 year for office space, operating facilities, equipment and personal property.

As of March 31, 2008, we had restricted cash in the amount of $3,250,000 held in an escrow account to be used for future payments in connection with the acquisition of Competition. The former owner of Competition will receive annual installments of $650,000 payable over a 5 year term from the escrow account.

Debt Requirements

The covenants contained in the credit agreement for our senior secured revolving credit facility include restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, capital expenditures, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. The credit agreement requires that we meet a maximum consolidated leverage ratio, a minimum interest coverage ratio and, if the leverage ratio is greater than 2.25 to 1.00, a minimum asset coverage ratio. In addition, the credit agreement contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.

Effective June 11, 2008, we entered into a Waiver Agreement with the Lenders to waive the requirement to provide certain financial statements and our compliance certificate within the time period required by the credit agreement. The Waiver Agreement now requires us to provide the financial statements and our compliance certificate on or before August 13, 2008. Until we provide these financial statements and our compliance certificate, the aggregate principal amount outstanding under the credit agreement may not exceed $350 million at any time (provided, however, that the commitment fee will continue to be calculated based on the total commitment of $400 million), and the per annum margin applicable to all amounts outstanding under the credit agreement will increase from the current rate of 2.25% for LIBOR rate borrowings and 1.25% for bank prime rate borrowings to 2.50% for LIBOR rate borrowings and 1.50% for bank prime rate borrowings. The required financial statements and our compliance certificate are being delivered concurrently with the filing of this Quarterly Report on Form 10-Q.

Results of Operations

Effective March 1, 2008, we acquired the production services businesses of WEDGE and Competition which provide well services, wireline services and fishing and rental services with a fleet of 62 workover rigs, 51 wireline units and approximately $13 million of fishing and rental tools equipment through its facilities in Texas, Kansas, North Dakota, Colorado, Utah, Montana and Oklahoma. The acquisitions of the production services businesses of WEDGE and Competition resulted in the formation of our new operating segment, the Production Services Division. We consolidated the results of these acquisitions from the day they were acquired. These acquisitions affect the comparability from period to period of our historical results, and our historical results may not be indicative of our future results.

Statement of Operations Analysis

The following table provides information for our operations for the three months ended March 31, 2008 and 2007 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue days information):

	Three Months Ended March 31, 2008	2007
Drilling Services Division:		
Revenues	$ 100,041	$ 103,347
Operating costs	63,497	59,189
Drilling Services Division margin	$ 36,544	$ 44,158
Average number of drilling rigs	67.0	64.3
Utilization rate	84%	90%
Revenue days	5,186	5,203
Average revenues per day	$ 19,291	$ 19,863
Average operating costs per day	12,244	11,376
Drilling Services Division margin per day	$ 7,047	$ 8,487

Production Services Division:		
Revenues	$ 13,356	$
Operating costs	6,929	
Production Services Division margin	$ 6,427	$
EBITDA	$ 36,206	$ 40,342

We present Drilling Services Division margin, Production Services Division margin and earnings before interest, taxes, depreciation and amortization (EBITDA) information because we believe they provide investors and our management additional information to assist them in assessing our business and performance in comparison to other companies in our industry. Since Drilling Services Division margin, Production Services Division margin and EBITDA information are non-GAAP financial measures under the rules and regulations of the SEC, we have included below a reconciliation of Drilling Services Division margin, Production Services Division margin and EBITDA to net earnings, which is the nearest comparable GAAP financial measure.

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	Three Months Ended March 31, 2008	2007
	(in thousands)	
Reconciliation of combined Drilling Services Dvision margin and Production Services Division margin and EBITDA to net earnings:		
Drilling Services Division margin	$ 36,544	$ 44,158
Production Services Division margin	6,427	
Combined margin	42,971	44,158
Selling, general and administrative	(7,722)	(3,824)
Bad debt expense	(135)	
Other income (expense)	1,092	8
EBITDA	36,206	40,342
Depreciation and amortization	(17,119)	(14,736)
Interest income (expense), net	(989)	881
Income tax expense	(6,250)	(9,269)
Net earnings	$ 11,848	$ 17,218

Our Drilling Services Division s revenues decreased by $3.3 million, or 3%, for the quarter ended March 31, 2008, as compared to the corresponding quarter in 2007, primarily due to a decrease in contract drilling revenues of $572 per day, or 3%, resulting from a reduced demand for drilling rigs.

Our Drilling Services Division s operating costs grew by $4.3 million, or 7%, for the quarter ended March 31, 2008, as compared to the corresponding period in 2007, due to a $868 increase in the average operating costs per revenue day, which was primarily due to higher operating costs per day for our Colombian operations, an increase in employee related costs for rig personnel, an increase in supplies, repairs and maintenance expenses and more turnkey and footage costs. Under turnkey and footage contracts, we provide supplies and materials such as fuel, drill bits, casing and drilling fluids, which significantly add to drilling costs when compared to daywork contracts. These costs are also included in the revenues we recognize for turnkey and footage contracts, resulting in higher revenue rates per day for turnkey and footage contracts compared to daywork contracts, which do not include such costs.

Our Production Services Division s revenue of $13.4 million and operating costs of $6.9 million are based on the operating results for this new operating segment which was created on March 1, 2008 when we acquired the production services businesses of WEDGE and Competition.

Our selling, general and administrative expense for the quarter ended March 31, 2008 increased by approximately $3.9 million, or 102%, compared to the corresponding quarter in 2007. The increase resulted from $1.5 million in additional compensation-related expenses incurred for existing and new employees in our corporate office. Professional and consulting expenses increased $0.6 million during the quarter ended March 31, 2008. In addition, we incurred $1.2 million and $.6 million of additional selling, general and administrative expenses relating to our Production Service Division and our Colombian operations, respectively.

Our other income for the quarter ended March 31, 2008 increased by $1.1 million compared to the corresponding quarter in 2007, primarily due to foreign currency translation gains relating to our operations in

Colombia.

Our depreciation and amortization expenses for the quarter ended March 31, 2008 increased by $2.4 million, or 16%, compared to the corresponding quarter in 2007. The increases resulted primarily from additional depreciation and amortization expense of $1.3 million for our new Production Services Division and an increase in the average size of our drilling rig fleet, which increase consisted of newly constructed rigs. Partially offsetting the increase in depreciation and amortization expense was a decrease of approximately $0.9 million resulting from the change in the estimated useful lives of a group of 19 drilling rigs from an average useful life of 9 years to 12 years.

Interest expense for the quarter ended March 31, 2008 is related to interest due on the amounts outstanding under our new senior secured revolving credit facility which was used to fund the acquisitions of the production services businesses of WEDGE and Competition on March 1, 2008.

Our effective income tax rate of 34.5% for the quarter ended March 31, 2008 differs from the federal statutory rate of 35% due to tax benefits in foreign jurisdictions, tax benefits recognized for previously unrecognized deferred tax assets and state income taxes.

Inflation

Due to the increased rig count in each of our market areas, availability of personnel to operate our rigs is limited. In April 2005, January 2006 and May 2006, we raised wage rates for our drilling rig personnel by an average of 6%, 6% and 14%, respectively. We were able to pass these wage rate increases on to our customers based on contract terms. We anticipate an additional wage rate increase of 10% to 15% prior to December 31, 2008 that we expect to pass on to our customers.

We are experiencing increases in costs for rig repairs and maintenance and costs of rig upgrades and new rig construction, due to the increased industry-wide demand for equipment, supplies and service. We estimate these costs increased by 10% to 15% in fiscal year 2007. We expect similar cost increases during the remainder of the fiscal year ending December 31, 2008 as rig counts remain at historically high levels.

Off Balance Sheet Arrangements

We do not currently have any off balance sheet arrangements.

Critical Accounting Policies and Estimates

Revenue and cost recognition Our Drilling Services Division earns revenues by drilling oil and gas wells for our customers under daywork, turnkey or footage contracts, which usually provide for the drilling of a single well. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey and footage contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. Individual contracts are usually completed in less than 60 days. The risks to us under a turnkey contract and, to a lesser extent, under footage contracts, are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors services, supplies, cost escalations and personnel operations.

Our management has determined that it is appropriate to use the percentage-of-completion method, as defined in the American Institute of Certified Public Accountants Statement of Position 81-1, to recognize revenue on our turnkey and footage contracts. Although our turnkey and footage contracts do not have express terms that provide us with rights to receive payment for the work that we perform prior to drilling wells to the agreed-on depth, we use this method because, as provided in applicable accounting literature, we believe we achieve a continuous sale for our work-in-progress and believe, under applicable state law, we ultimately could recover the fair value of our work-in-progress even in the event we were unable to drill to the agreed-on depth in breach of the applicable contract. However, in the event we were unable to drill to the agreed-on depth in breach of the contract, ultimate recovery of that value would be subject to negotiations with the customer and the possibility of litigation.

If a customer defaults on its payment obligation to us under a turnkey or footage contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey and footage contracts do not expressly grant to us a security interest in the work we have completed under the contract and we have no ownership rights in the work-in-progress or completed drilling work, except any rights arising under the applicable lien statute on foreclosure. If we were unable to drill to the agreed-on depth in breach of the contract, we also would need to rely on equitable remedies outside of the contract, including quantum meruit, available in applicable courts to recover the fair value of our work-in-progress under a turnkey or footage contract.

We accrue estimated contract costs on turnkey and footage contracts for each day of work completed based on our estimate of the total costs to complete the contract divided by our estimate of the number of days to complete the contract. Contract costs include labor, materials, supplies, repairs and maintenance, operating overhead allocations and allocations of depreciation and amortization expense. In addition, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey and footage contracts could have a material adverse effect on our financial position and results of operations. Therefore, our actual results for a contract could differ significantly if our cost estimates for that contract are later revised from our original cost estimates for a contract in progress at the end of a reporting period which was not completed prior to the release of our financial statements.

With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the contract term of certain drilling contracts. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs.

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The asset contract drilling in progress represents revenues we have recognized in excess of amounts billed on contracts in progress. The asset prepaid expenses and other includes deferred mobilization costs for certain drilling contracts. The liability prepaid drilling contracts represents deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized.

Our Production Services Division earns revenues for well services, wireline services and fishing and rental services pursuant to master services agreements based on purchase orders, contracts or other persuasive evidence of an arrangement with the customer that include fixed or determinable prices. Production service revenue is recognized when the service has been rendered and collectability is reasonably assured.

Asset impairments We assess the impairment of property and equipment whenever events or circumstances indicate that the carrying value may not be recoverable. Factors that we consider important and which could trigger an impairment review would be our customers financial condition, local conditions in a particular market and any significant negative industry or economic trends. More specifically, among other things, we consider our contract revenue rates; our utilization rates; cash flows from our drilling rigs, workover rigs, wireline units and fishing and rental tools equipment; current oil and gas prices, rig counts and trends in the price of used equipment observed by our management. If a review of our property and equipment indicates that our carrying value exceeds the estimated undiscounted future net cash flows, we are required under applicable accounting standards to write down the property and equipment to its fair market value. A one percent write-down in our net property and equipment, at March 31, 2008, would have resulted in a corresponding decrease in our net earnings of approximately $3.7 million for the three months ended March 31, 2008.

Goodwill Impairments Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. We account for goodwill and other intangible assets under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Goodwill and other intangible assets not subject to amortization are tested for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. SFAS No. 142 requires a two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit s goodwill is determined by allocating the unit s fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value.

Deferred taxes We provide deferred taxes for the basis differences in our property and equipment between financial reporting and tax reporting purposes and other costs such as compensation, foreign net operating loss carryforwards, employee benefit and other accrued liabilities which are deducted in different periods for financial reporting and tax reporting purposes. For property and equipment, basis differences arise from differences in depreciation periods and methods and the value of assets acquired in a business acquisition where we acquire an entity rather than just its assets. For financial reporting purposes, we depreciate the various components of our drilling rigs, workover rigs and wireline units over 5 to 25 years and refurbishments over 3 to 5 years, while federal income tax rules require that we depreciate drilling rigs, workover rigs, wireline units and refurbishments over 5 years. Therefore, in the first 5 years of our ownership of a drilling rig, workover rig or wireline unit, our tax depreciation exceeds our financial reporting depreciation, resulting in our providing deferred taxes on this depreciation difference. After 5 years, financial reporting depreciation exceeds tax depreciation, and the deferred tax liability begins to reverse.

Accounting estimates We consider the recognition of revenues and costs on turnkey and footage contracts to be critical accounting estimates. On these types of contracts, we are required to estimate the number of days needed for us to complete the contract and our total cost to complete the contract. Our actual costs could substantially exceed our estimated costs if we encounter problems such as lost circulation, stuck drill pipe or an underground blowout on contracts still in progress subsequent to the release of the financial statements.

We receive payment under turnkey and footage contracts when we deliver to our customer a well completed to the depth specified in the contract, unless the customer authorizes us to drill to a more shallow depth. Since 1995, we have completed all our turnkey or footage contracts. Although our initial cost estimates for turnkey and footage contracts do not include cost estimates for risks such as stuck drill pipe or loss of circulation, we believe that our experienced management team, our knowledge of geologic formations in our areas of operations, the condition of our drilling equipment and our experienced crews have previously enabled us to make reasonable cost estimates and complete contracts according to our drilling plan. While we do bear the risk of loss for cost overruns and other events that are not specifically provided for in our initial cost estimates, our pricing of turnkey and footage contracts takes such risks into consideration. When we encounter, during the course of our drilling operations, conditions unforeseen in the preparation of our original cost estimate, we increase our cost estimate to complete the contract. If we anticipate a loss on a contract in progress at the end of a reporting period due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. During the three months ended March 31, 2008, we experienced losses on 2 of the 23 turnkey and footage contracts completed, with a loss of less than $25,000 on one of these contracts and a loss of less than $125,000 on the other contract. We are more likely to encounter losses on turnkey and footage contracts in periods in which revenue rates are lower for all types of contracts. During periods of reduced demand for drilling rigs, our overall profitability on turnkey and footage contracts has historically exceeded our profitability on daywork contracts.

Revenues and costs during a reporting period could be affected for contracts in progress at the end of a reporting period which have not been completed before our financial statements for that period are released. We had 1 turnkey and 3 footage contracts in progress at March 31, 2008, which were completed prior to the release of the financial statements included in this report. Our contract drilling in progress totaled $16.6 million at March 31, 2008. Of that amount accrued, turnkey and footage contract revenues were $1.6 million. The remaining balance of $14.4 million related to the revenue recognized but not yet billed on daywork drilling contracts in progress at March 31, 2008 and $0.6 million related to unbilled revenue for our Production Services Division.

We estimate an allowance for doubtful accounts based on the creditworthiness of our customers as well as general economic conditions. We evaluate the creditworthiness of our customers based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the customer. Consequently, an adverse change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new customers to establish escrow accounts or make prepayments. We typically invoice our customers at 15-day intervals during the performance of daywork contracts and upon completion of the daywork contract. Turnkey and footage contracts are invoiced upon completion of the contract. Our typical contract provides for payment of invoices in 10 to 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our contracts in the last three fiscal years. We had an allowance for doubtful accounts of $0.3 million at March 31, 2008 and no allowance for doubtful accounts at December 31, 2007.

Our determination of the useful lives of our depreciable assets, which directly affects our determination of depreciation expense and deferred taxes is also a critical accounting estimate. A decrease in the useful life of our property and equipment would increase depreciation expense and reduce deferred taxes. We provide for depreciation of our drilling, production, transportation and other equipment on a straight-line method over useful lives that we have estimated and that range from 3 to 25 years. We record the same depreciation expense whether a drilling rig, workover rig or wireline unit is idle or working. Our estimates of the useful lives of our drilling, production, transportation and other equipment are based on our more than 35 years of experience in the oilfield services industry with similar equipment. Effective January 1, 2008, we reassessed the estimated useful lives assigned to a group of 19 drilling rigs that were recently constructed. These drilling rigs were constructed with new components that have longer estimated useful lives when compared to other drilling rigs that are equipped with older components. As a result, we increased the estimated useful lives for this group of recently constructed drilling rigs from an average useful life of 9 years to 12 years. This change in the estimated useful lives of this group of 19 drilling rigs resulted in a $0.9 million decrease in depreciation and amortization expense for the quarter ended March 31, 2008.

As of March 31, 2008, we had foreign net operating losses for tax purposes and other tax benefits available to reduce future taxable income in a foreign jurisdiction. The valuation allowance in the amount of $4.0 million offsets in part our foreign net operating losses and other tax benefits. In assessing the realizability of our foreign deferred tax assets, we recognized a tax benefit to the extent of taxable income we expect to earn over the terms of three existing drilling contracts in the foreign jurisdiction. The terms of these contracts expire in October 2008, December 2008 and March 2009. If one or more of these contracts are extended or renewed or new contracts are entered into, then we expect to recognize additional tax benefits to the extent projected future taxable income increases. The foreign net operating loss has an indefinite carryforward period. The foreign net operating loss is primarily due to the special income tax benefits permitted by the Colombian government that allows us to recover 140% of the cost of certain imported assets. We are currently marketing a 1500 horsepower drilling rig that we plan to deploy in Colombia. To obtain this special income tax benefit, we plan to have our U.S operating company sell this drilling rig to Stayton Asset Group, a variable interest entity established for this transaction for which we are the primary beneficiary. We plan to have Stayton Asset Group immediately sell this drilling rig to our operating entity in Colombia.

Our accrued insurance premiums and deductibles as of March 31, 2008 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $0.9 million and our workers compensation, general liability and auto liability insurance of approximately $9.8 million. We have a deductible of $125,000 per covered individual per year under the health insurance, except for individuals employed by our Production Services Division where we have no deductible. We have a deductible of $500,000 per occurrence under our workers compensation insurance, except in North Dakota, where we do not have a deductible. We have deductibles of $250,000 and $100,000 per occurrence under our general liability insurance and auto liability insurance, respectively. We accrue for these costs as claims are incurred based on historical claim development data, and we accrue the costs of administrative services associated with claims processing. We also evaluate our workers compensation claim cost estimates based on estimates provided by a professional actuary.

Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosure of fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements and, accordingly, does not require any new fair value measurements. SFAS No. 157, as issued, was effective for financial statement issued for fiscal years beginning after November

15, 2007, and interim periods within those fiscal years. However, on February 12, 2008, the FASB issued FSP FAS No. 157-2, *Effective Dates of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations and financial condition.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 159 did not have a material impact on our financial position or results of operations and financial condition.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling interests in Consolidated Financial Statements an Amendment of ARB No. 51*. This statement establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 clarifies that a non-controlling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS No. 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the non-controlling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the non-controlling interest. SFAS No.160 is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption to have a material impact on our financial position or results of operations and financial condition.

In December 2007, the FASB issued SFAS No. 141R (revised 2007) which replaces SFAS No. 141, *Business Combinations* (SFAS No. 141R). SFAS No. 141R applies to all transactions and other events in which one entity obtains control over one or more other businesses. SFAS No. 141R requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. This fair value approach replaces the cost-allocation process required under SFAS No. 141 whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. SFAS No. 141R requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. Under SFAS No.141R, the requirements of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the recognition criteria of SFAS No. 5, *Accounting for Contingencies*. SFAS No.141R is expected to have a significant impact on our accounting for business combinations closing on or after January 1, 2009.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS No. 161). SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The guidance in SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The Company is currently assessing the impact of SFAS No. 161. We do not have any derivative instruments and expect the adoption of SFAS No. 161 to have no impact on our financial position or results of operations and financial condition.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

We are subject to interest rate market risk on our variable rate debt. As of March 31, 2008, we had $289.5 million outstanding under our senior secured revolving credit facility subject to variable interest rate risk. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $0.7 million and a decrease in net income of approximately $0.5 million during a quarterly period.

At March 31, 2008, we held $16.5 million (par value) of investments comprised of tax exempt, auction rate preferred securities (ARPSs), which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through Dutch auctions that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds, backed by assets that are equal to or greater than 200% of the liquidation preference and guaranteed by monoline bond insurance companies. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several failed auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. We may not be able to access the funds we invested in our ARPSs without a loss of principal, unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately be able to liquidate our investments without material loss primarily due to the collateral securing the ARPSs. We do not currently intend to attempt to sell our ARPSs since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of March 31, 2008 because of our inability to determine the recovery period of our investment in ARPSs. Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders equity. The estimated fair value of our ARPSs at March 31, 2008 was $15.0 million compared with a par value of $16.5 million. The $1.5 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and is recorded as an unrealized loss. We would recognize an impairment charge if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary.

Foreign Currency Risk

Our international operations in Colombia expose us to movements in currency exchange rates, which may be volatile at times. The economic impact of currency exchange rate movements is complex because changes are often linked to various real growth, inflation, interest rates, governmental actions and other factors. These changes, if material, could cause us to change our financing and operating strategies.

During the quarter ended March 31, 2008, we operated 3 drilling rigs in Colombia that generated 8% of our total revenue. We estimate, based upon our net income for our Colombian operations for the quarter ended March 31, 2008, a 10% change in foreign currency exchange rates would not have resulted in a material impact to consolidated net income.

We do not currently use derivative financial instruments to hedge against interest rate risk or foreign currency risk.

ITEM 4. CONTROLS AND PROCEDURES

In accordance with Exchange Act Rules 13a-15 and 15d-15, 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 our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2008 to provide reasonable assurance 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 and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended March 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On March 1, 2008, we completed the acquisitions of the production services businesses of WEDGE and Competition. We are in the process of transferring all accounting for the new acquisition to our headquarters and into our existing internal control processes. The integration will lead to changes in these controls in future fiscal periods but we do not except these changes to materially affect our internal controls over financial reporting. Consistent with published guidance of the SEC, our management excluded the acquired companies from the scope of its assessment of internal control over financial reporting as of March 31, 2008. Total assets and total revenues from the acquisitions represented approximately 41% and 12%, respectively, of the related consolidated financial statement amounts of the Company for the three months ended March 31, 2008.

Investigation by the Special Subcommittee of the Board of Directors

On May 12, 2008, the Company announced a delay in filing its Form 10-Q for the quarter ended March 31, 2008 (the Quarterly Report), as a result of certain questions raised with respect to the effectiveness of the Company s internal control over financial reporting. On May 15, 2008, the Board of Directors formed a special subcommittee of the Board (the Special Committee) to investigate the questions raised regarding the Company s internal control over financial reporting and to determine whether such weaknesses, if any, have materially affected the Company s financial statements The Special Committee engaged Bracewell &

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Giuliani LLP (Bracewell), as independent legal counsel, and Deloitte & Touche LLP (Deloitte), as independent forensic accountants, to assist in the investigation.

In July 2008, after an extensive document review and interviewing relevant current and former employees and vendors, Bracewell presented their report to the Special Committee. After consideration of the report, the Special Committee then met with the Board of Directors, at which meeting Bracewell also presented its report to the Board of Directors, to discuss the report and present the Special Committee s recommendations.

After reviewing the report, the Special Committee and the Board of Directors concluded that they were not aware of any facts that caused them to believe that there was any material misstatement of the Company s historical financial statements or in the financial statements proposed to be included in the Quarterly Report.

Furthermore, based on the Bracewell report, the Special Committee and the Board do not believe that the questions raised constituted a material weakness in the Company s internal control over financial reporting. The Bracewell report, however, did identify certain control deficiencies and made recommendations, that have been adopted by the Board of Directors, to enhance the Company s governance and control environment.

The Bracewell report noted some deficiencies in the Company s manual process to record purchases and process expenditures, for both expense and capital expenditures. While there were certain compensating controls that mitigated the financial reporting risks associated with these deficiencies, the Bracewell report recommended that the Company implement a more effective systematic purchase order application integrated with the general ledger. Consistent with the recommendation in the Bracewell report, the Company intends to enhance its current process by expanding, upgrading, better systematizing and making prospective its current purchase order system.

The Bracewell report and the Special Committee s review also noted the desirability to improve communications and more clearly delineate roles and responsibilities within the Company. As recommended in the Bracewell report, the Company intends to hire a general counsel and chief compliance officer, to further define roles and responsibilities, and to undertake a series of training initiatives.

The Bracewell report also reviewed certain matters related to the Company s Colombian operations. In light of the recent commencement of these operations and cultural and other issues involved in integrating them into the Company and its systems, including documentation procedures, the Bracewell report recommended, and the Board has already begun to focus on, additional oversight of these operations as the Company continues the intended expansion in this market.

Finally, the Board has directed management to consider and report back to the Board with respect to the implementation of additional controls and procedures. These include a disclosure committee comprised of representatives from operations, compliance and finance and accounting and a quarterly subcertification and management representation process with signoff by segment and service line operating executives and controllers, corporate accounting managers and other personnel involved in the financial reporting process. These processes should enhance internal accountability for our financial statements.

While some matters raised during the process of the investigation require additional review by the Special Committee and its counsel, the Company does not believe they will have a material impact on the Company s financial statements or operations.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are involved in litigation arising in the ordinary course of our business. Although the amount of any liability that could arise with respect to these actions cannot be accurately predicted, in management s opinion, any such liability will not have a material adverse effect on our business, financial condition or operating results.

ITEM 1A. RISK FACTORS

While we attempt to identify, manage and mitigate risks and uncertainties associated with our business to the extent practical under the circumstances, some level of risk and uncertainty will always be present. Part I, Item 1A of our Transition Report on Form 10-KT for the fiscal year ended December 31, 2007 describes some of the risks and uncertainties associated with our business that have the potential to materially affect our business, financial condition or results of operations. The risk factors presented below update, and should be considered in addition to, the risk factors previously disclosed by us in such Transition Report on Form 10-KT. Additional risks and uncertainties not presently known to us or that we currently believe are immaterial also may negatively impact our business, financial condition or operating results.

Set forth below are various risks and uncertainties that could adversely impact our business, financial condition, results of operations and cash flows.

Risks Relating to the Oil and Gas Industry

We derive all our revenues from companies in the oil and gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility of oil and gas prices.

As a provider of contract land drilling services and oil and gas production services, our business depends on the level of exploration and production activity by oil and gas companies operating in the geographic markets where we operate. The oil and gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and gas prices, and market expectations of potential changes in those prices, significantly affect the levels of those activities. Worldwide political, economic, and military events as well as natural disasters have contributed to oil and gas price volatility and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in oil and gas prices or otherwise, could materially and adversely affect us in many ways by negatively impacting:

- our revenues, cash flows and profitability;
- the fair market value of our drilling rig fleet and production service assets;
- our ability to maintain or increase our borrowing capacity;
- our ability to obtain additional capital to finance our business and make acquisitions, and the cost of that capital; and
- our ability to retain skilled rig personnel whom we would need in the event of an upturn in the demand for our services.

Depending on the market prices of oil and gas, oil and gas exploration and production companies may cancel or curtail their drilling programs and may lower production spending on existing wells, thereby reducing demand for our services. Oil and gas prices have been volatile historically and, we believe, will continue to be so in the future. Many factors beyond our control affect oil and gas prices, including:

- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;

available pipeline and other oil and gas transportation capacity;

the ability of oil and gas companies to raise capital;

economic conditions in the United States and elsewhere;

actions by OPEC, the Organization of Petroleum Exporting Countries;

political instability in the Middle East and other major oil and gas producing regions;

governmental regulations, both domestic and foreign;

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- domestic and foreign tax policy;
- weather conditions in the United States and elsewhere;
- the pace adopted by foreign governments for the exploration, development and production of their national reserves;
- the price of foreign imports of oil and gas; and
- the overall supply and demand for oil and gas.

Risks Relating to Our Business

Reduced demand for or excess capacity of drilling services or production services could adversely affect our profitability.

Our profitability in the future will depend on many factors, but largely on pricing and utilization rates for our drilling and production services. A reduction in the demand for drilling rigs or an increase in the supply of drilling rigs, whether through new construction or refurbishment, could decrease the dayrates and utilization rates for our drilling services, which would adversely affect our revenues and profitability. An increase in supply of well service rigs, wireline units and fishing and rental tools equipment, without a corresponding increase in demand, could similarly decrease the pricing and utilization rates of our production services, which would adversely affect our revenues and profitability.

We operate in a highly competitive, fragmented industry in which price competition could reduce our profitability.

We encounter substantial competition from other drilling contractors and other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that drilling, workover and well-servicing rigs are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of rigs in an area. Contract drilling companies and other oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs from other regions. An influx of rigs from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for drilling or production services short-lived.

Most drilling services contracts and production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and rig availability, we believe the following factors are also important to our customers in determining which drilling services or production services provider to select:

- the type and condition of each of the competing drilling, workover and well-servicing rigs;
- the mobility and efficiency of the rigs;
- the quality of service and experience of the rig crews;
- the safety records of the rigs;
- the offering of ancillary services; and
- the ability to provide drilling and production equipment adaptable to, and personnel familiar with, new technologies and drilling and production techniques.

While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, the safety record of our rigs, our ability to offer ancillary services and the quality of service and experience of our rig crews to differentiate us from our competitors. This strategy is less effective as lower demand for drilling and production services or an oversupply of drilling, workover and well-servicing rigs intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price. In all of the markets in which we compete, an oversupply of rigs can cause greater price competition, which can reduce our profitability.

We face competition from many competitors with greater resources.

Many of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to:

better withstand industry downturns;

compete more effectively on the basis of price and technology;

retain skilled rig personnel; and

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build new rigs or acquire and refurbish existing rigs so as to be able to place rigs into service more quickly than us in periods of high drilling demand.

Unexpected cost overruns on our turnkey drilling jobs and our footage contracts could adversely affect our financial position and our results of operations.

We have historically derived a portion of our revenues from turnkey drilling contracts, and turnkey contracts may represent a component of our future revenues. The occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey jobs could have a material adverse effect on our financial position and results of operations. Under a typical turnkey drilling contract, we agree to drill a well for our customer to a specified depth and under specified conditions for a fixed price. We provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. We often subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, we do not receive progress payments and are paid by our customer only after we have performed the terms of the drilling contract in full. For these reasons, the risk to us under a turnkey drilling contract is substantially greater than for a well drilled on a daywork basis because we must assume most of the risks associated with drilling operations that the operator generally assumes under a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors services, supplies, cost escalations and personnel. Similar to our turnkey contracts, under a footage contract we assume most of the risks associated with drilling operations that the operator generally assumes under a daywork contract.

Although we attempt to obtain insurance coverage to reduce certain of the risks inherent in our turnkey drilling operations, adequate coverage may be unavailable in the future and we might have to bear the full cost of such risks, which could have an adverse effect on our financial condition and results of operations.

Our operations involve operating hazards, which, if not insured or indemnified against, could adversely affect our results of operations and financial condition.

Our operations are subject to the many hazards inherent in the drilling, workover and well-servicing industries, including the risks of:

- blowouts;
- cratering;
- fires and explosions;
- loss of well control;
- collapse of the borehole;
- damaged or lost drilling equipment; and
- damage or loss from natural disasters.

Any of these hazards can result in substantial liabilities or losses to us from, among other things:

- suspension of operations;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life;
- damage to producing or potentially productive oil and gas formations through which we drill; and
- environmental damage.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include pollution liability in excess of relatively low limits. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers. However, customers who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may be unable to maintain adequate insurance in the future at rates we consider reasonable.

We face increased exposure to operating difficulties because we primarily focus on providing drilling and production services for natural gas.

Most of our drilling and production contracts are with exploration and production companies in search of natural gas. Drilling on land for natural gas generally occurs at deeper drilling depths than drilling for oil. Although deep-depth drilling and production services expose us to risks similar to risks encountered in shallow-depth drilling and production services, the magnitude of the risk for deep-depth drilling and production services is greater because of the higher costs and greater complexities involved in providing drilling and production services for deep wells. We generally do not insure risks related to operating difficulties other than blowouts. If we do not adequately insure the increased risk from blowouts or if our contractual indemnification rights are insufficient or unfulfilled, our profitability and other results of operations and our financial condition could be adversely affected in the event we encounter blowouts or other significant operating difficulties while providing drilling or production services at deeper depths.

Our current primary focus on drilling for customers in search of natural gas could place us at a competitive disadvantage if we were to change our primary focus to drilling for customers in search of oil.

Our drilling rig fleet consists of rigs capable of drilling on land at drilling depths of 6,000 to 18,000 feet because most of our contracts are with customers drilling in search of natural gas, which generally occurs at deeper drilling depths than drilling in search of oil, which often occurs at drilling depths less than 6,000 feet. Generally, larger drilling rigs capable of deep drilling generally incur higher mobilization costs than smaller drilling rigs drilling at shallower depths. If our primary focus shifts from drilling for customers in search of natural gas to drilling for customers in search of oil, the majority of our rig fleet would be disadvantaged in competing for new oil drilling projects as compared to competitors that primarily use shallower drilling depth rigs when drilling in search of oil.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

From time to time there have been shortages of drilling and production services equipment and supplies during periods of high demand which we believe could recur. Shortages could result in increased prices for drilling and production services equipment or supplies that we may be unable to pass on to customers. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in our obtaining drilling and production services equipment or supplies could limit drilling and production services operations and jeopardize our relations with customers. In addition, shortages of drilling and production services equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our operations require the services of employees having the technical training and experience necessary to obtain the proper operational results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Shortages of qualified personnel are occurring in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. A significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material and adverse effect on our financial condition and results of operations.

Our acquisition strategy exposes us to various risks, including those relating to difficulties in identifying suitable acquisition opportunities and integrating businesses, assets and personnel, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

As a key component of our business strategy, we have pursued and intend to continue to pursue acquisitions of complementary assets and businesses. For example, since March 31, 2003, our drilling rig fleet has increased from 24 to 69 drilling rigs, primarily as a result of acquisitions. In addition, during the first quarter of 2008, we completed the acquisition of the production services businesses of WEDGE and Competition.

Our acquisition strategy in general, and our recent acquisitions in particular, involve numerous inherent risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including environmental liabilities;

difficulties in integrating the operations and assets of the acquired business and the acquired personnel;

limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business in order to comply with applicable periodic reporting requirements;

potential losses of key employees and customers of the acquired businesses;

risks of entering markets in which we have limited prior experience; and

increases in our expenses and working capital requirements.

The process of integrating an acquired business may involve unforeseen costs and delays or other operational, technical and financial difficulties that may require a disproportionate amount of management attention and financial and other resources. Possible future acquisitions may be for purchase prices significantly higher than those we paid for previous acquisitions. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, we may not have sufficient capital resources to complete additional acquisitions. Historically, we have funded the growth of our rig fleet through a combination of debt and equity financing. We may incur substantial additional indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with such acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity or convertible securities could be dilutive to our existing shareholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms.

Even if we have access to the necessary capital, we may be unable to continue to identify additional suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets.

Our strategy of constructing drilling rigs during periods of peak demand requires that we maintain an adequate supply of drilling rig components to complete our rig building program. Our suppliers may be unable to continue providing us the needed drilling rig components if their manufacturing sources are unable to fulfill their commitments.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

For several years we have had little or no long-term debt. In connection with the acquisition of the production services businesses of WEDGE and Competition, we entered into a new $400 million, five-year, senior secured revolving credit facility. As of March 31, 2008, our total debt was approximately $295.0 million.

Our current and future indebtedness could have important consequences, including:

- impairing our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;
- making us more vulnerable to a downturn in our business, our industry or the economy in general as a substantial portion of our operating cash flow will be required to make principal and interest payments on our indebtedness, making it more difficult to react to changes in our business and in industry and market conditions;
- limiting our ability to obtain additional financing that may be necessary to operate or expand our business;
- putting us at a competitive disadvantage to competitors that have less debt; and
- increasing our vulnerability to interest rate increases to the extent that we incur variable rate indebtedness.

We anticipate that our cash generated by operations and our ability to borrow under the currently unused portion of our senior secured revolving credit facility should allow us to meet our routine financial obligations for the foreseeable future. However, our ability to make payments on our indebtedness, and to fund planned capital expenditures, will depend on our ability to generate cash in the future. This, to a certain extent, is subject to conditions in the oil and gas industry, general economic and financial conditions, competition in the markets where we operate, the impact of legislative and regulatory actions on how we conduct our business and other factors, all of which are beyond our control. If our business does not generate sufficient cash flow from operations to service our outstanding indebtedness, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;

reducing or delaying acquisitions or capital investments, such as refurbishments of our rigs and related equipment; or

seeking to raise additional capital.

However, we may be unable to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, and any such alternative financing plans might be insufficient to allow us to meet our debt obligations. If we are unable to generate sufficient cash flow or are otherwise unable to obtain the funds required to make principal and interest payments on our indebtedness, or if we otherwise fail to comply with the various covenants in our senior secured revolving credit facility or other instruments governing any future indebtedness, we could be in default under the terms of our senior secured revolving credit facility or such instruments. In the event of a default, the Lenders under our senior secured revolving credit facility could elect to declare all the loans made under such facility to be due and payable together with accrued and unpaid interest and terminate their commitments thereunder and we or one or more of our subsidiaries could be forced into bankruptcy or liquidation. Any of the foregoing consequences could materially and adversely affect our business, financial condition, results of operations and prospects.

Our senior secured revolving credit facility imposes restrictions on us that may affect our ability to successfully operate our business.

Our senior secured revolving credit facility limits our ability to take various actions, such as:

- limitations on the incurrence of additional indebtedness;
- restrictions on investments, mergers or consolidations, asset dispositions, acquisitions, transactions with affiliates and other transactions without the Lenders consent; and
- limitation on dividends and distributions.

In addition, our senior secured revolving credit facility requires us to maintain certain financial ratios and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with them. The failure to comply with any of these financial conditions, such as financial ratios or covenants, would cause an event of default under our senior secured revolving credit facility. An event of default, if not waived, could result in acceleration of the outstanding indebtedness under our senior secured revolving credit facility, in which case the debt would become immediately due and payable. If this occurs, we may not be able to pay our debt or borrow sufficient funds to refinance it. Even if new financing is available, it may not be available on terms that are acceptable to us. These restrictions could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our senior secured revolving credit facility.

Our international operations are subject to political, economic and other uncertainties not encountered in our domestic operations.

As we continue to implement our strategy of expanding into areas outside the United States, our international operations will be subject to political, economic and other uncertainties not generally encountered in our U.S. operations. These will include, among potential others:

- risks of war, terrorism, civil unrest and kidnapping of employees;
- expropriation, confiscation or nationalization of our assets;
- renegotiation or nullification of contracts;
- foreign taxation;
- the inability to repatriate earnings or capital due to laws limiting the right and ability of foreign subsidiaries to pay dividends and remit earnings to affiliated companies;
- changing political conditions and changing laws and policies affecting trade and investment;
- regional economic downturns;
- the overlap of different tax structures;
- the burden of complying with multiple and potentially conflicting laws;

- the risks associated with the assertion of foreign sovereignty over areas in which our operations are conducted;
- difficulty in collecting international accounts receivable; and
- potentially longer payment cycles.

Our international operations may also face the additional risks of fluctuating currency values, hard currency shortages and controls of foreign currency exchange. Additionally, in some jurisdictions, we may be subject to foreign governmental regulations favoring or requiring the awarding of contracts to local contractors or requiring foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These regulations could adversely affect our ability to compete.

Our operations are subject to various laws and governmental regulations that could restrict our future operations and increase our operating costs.

Many aspects of our operations are subject to various federal, state and local laws and governmental regulations, including laws and regulations governing:

- environmental quality;
- pollution control;
- remediation of contamination;
- preservation of natural resources; and
- worker safety.

Our operations are subject to stringent federal, state and local laws, rules and regulations governing the protection of the environment and human health and safety. Some of those laws, rules and regulations relate to the disposal of hazardous substances, oilfield waste and other waste materials and restrict the types, quantities and concentrations of those substances that can be released into the environment. Several of those laws also require removal and remedial action and other cleanup under certain circumstances, commonly regardless of fault. Our operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Planning, implementation and maintenance of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are also subject to these regulatory requirements. In addition, our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for accidental discharges of oil, gas, drilling fluids, contaminated water or other substances, or for noncompliance with other aspects of applicable laws and regulations.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, the federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Safe Drinking Water Act, the Occupational Safety and Health Act, or OSHA, and their state counterparts and similar statutes are the primary statutes that impose the requirements described above and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental Protection Agency community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the Superfund law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

Environmental laws and regulations are complex and subject to frequent change. Failure to comply with governmental requirements or inadequate cooperation with governmental authorities could subject a responsible party to administrative, civil or criminal action. We may also be exposed to environmental or other liabilities originating from businesses and assets which we acquired from others. Our compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination or regulatory noncompliance may require us to make material expenditures or subject us to liabilities that we currently do not anticipate.

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In addition, our business depends on the demand for land drilling and production services from the oil and gas industry and, therefore, is affected by tax, environmental and other laws relating to the oil and gas industry generally, by changes in those laws and by changes in related administrative regulations. It is possible that these laws and regulations may in the future add significantly to our operating costs or those of our customers, or otherwise directly or indirectly affect our operations.

Our combined operating history may not be sufficient for investors to evaluate our business and prospects.

The acquisition of the production services businesses of WEDGE and Competition significantly expanded our operations and assets. Our historical combined financial statements include financial information based on the separate production services businesses of WEDGE and Competition. As a result, the historical and pro forma information presented may not provide an accurate indication of what our actual results would have been if the acquisition of the production services businesses of WEDGE and Competition had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. Our future results will depend on our ability to efficiently manage our combined operations and execute our business strategy.

Risk Relating to Our Capitalization and Organizational Documents

We do not intend to pay dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our shareholders.

We have not paid or declared any dividends on our common stock and currently intend to retain any earnings to fund our working capital needs and growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and the restrictions imposed by the Texas Business Corporation Act and other applicable laws and by our credit facilities. Our debt arrangements include provisions that generally prohibit us from paying dividends on our capital stock, including our common stock.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our articles of incorporation authorize us to issue, without the approval of our shareholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company even if that change would be beneficial to our shareholders. Our articles of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our shareholders to nominate candidates for election as directors or to bring matters for action at annual meetings of our shareholders;
- limitations on the ability of our shareholders to call a special meeting and act by written consent;
- provisions dividing our board of directors into three classes elected for staggered terms; and
- the authorization given to our board of directors to issue and set the terms of preferred stock.

We may continue to experience market conditions that could adversely affect the liquidity of our auction rate preferred security investment.

At March 31, 2008, we held $16.5 million (par value) of investments comprised of tax exempt, auction rate preferred securities (ARPSs), which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through Dutch auctions that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds, backed by assets that are equal to or greater than 200% of the liquidation preference and guaranteed by monoline bond insurance companies. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several failed auctions, meaning that there was not

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enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. We may not be able to access the funds we invested in our ARPSs without a loss of principal, unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately be able to liquidate our investments without material loss primarily due to the collateral securing the ARPSs. We do not currently intend to attempt to sell our ARPSs since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of March 31, 2008 because of our inability to determine the recovery period of our investment in ARPSs. Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders equity. The estimated fair value of our ARPSs at March 31, 2008 was $15.0 million compared with a par value of $16.5 million. The $1.5 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and is recorded as an unrealized loss. We would recognize an impairment charge if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary.

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

We did not make any unregistered sales of equity securities during the quarter ended March 31, 2008, nor did we repurchase any shares of our common stock during the quarter ended March 31, 2008.

ITEM 3. Defaults Upon Senior Securities

Not Applicable.

ITEM 4. Submission of Matters to a Vote of Security Holders

None.

ITEM 5. Other Information

Not Applicable.

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ITEM 6. EXHIBITS

The following exhibits are filed as part of this report or incorporated by reference herein:

2.1 *	-	Securities Purchase Agreement, dated January 31, 2008, by and among Pioneer Drilling Company, WEDGE Group Incorporated, WEDGE Energy Holdings, L.L.C., WEDGE Oil & Gas Services, L.L.C., Timothy Daley, John Patterson and Patrick Grissom (Form 8-K dated February 1, 2008 (File No. 1-8182, Exhibit 2.1)).
2.2 *	-	Letter Agreement, dated February 29, 2008, amending the Securities Purchase Agreement, dated January 31, 2008, by and among Pioneer Drilling Company, WEDGE Group Incorporated, WEDGE Energy Holdings, L.L.C., WEDGE Oil & Gas Services, L.L.C., Timothy Daley, John Patterson and Patrick Grissom (Form 8-K dated March 3, 2008 (File No. 1-8182, Exhibit 2.1)).
3.1 *	-	Articles of Incorporation of Pioneer Drilling Company, as amended (Form 10-K for the year ended March 31, 2001 (File No. 1-8182, Exhibit 3.1)).
3.2 *	-	Articles of Amendment to the Articles of Incorporation of Pioneer Drilling Company (Form 10-Q for the quarter ended September 30, 2001 (File No. 1-8182, Exhibit 3.1)).
3.3 *	-	Amended and Restated Bylaws of Pioneer Drilling Company (Form 8-K dated December 10, 2007 (File No. 1-8182, Exhibit 3.1)).
4.1 *	-	Form of Certificate representing Common Stock of Pioneer Drilling Company (Form S-8 filed November 18, 2003 (Reg. No. 333-110569, Exhibit 4.3)).
10.1*	-	Credit Agreement, dated February 29, 2008, among Pioneer Drilling Company, as Borrower, and Wells Fargo Bank, N.A., as administrative agent, issuing lender, swing line lender and co-lead arranger, Fortis Bank SA/NV, New York Branch, as co-lead arranger, and each of the other parties listed therein (Form 8-K dated March 3, 2008 (File No. 1-8182, Exhibit 10.1)).
10.2*+	-	Employment Letter, effective March 1, 2008, from Pioneer Drilling Company to Joseph B. Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.1)).
10.3 *+	-	Confidentiality and Non-Competition Agreement, dated February 29, 2008, by and between Pioneer Drilling Company, Pioneer Production Services, Inc. and Joe Eustace (Form 8-K dated March 5, 2008 (File No. 1-8182, Exhibit 10.2)).
10.4 **+		Amended and Restated Pioneer Drilling Company Key Executive Severance Plan.
10.5 **+	-	Amended and Restated Pioneer Drilling Company 2007 Incentive Plan.
31.1 **	-	Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934.
31.2 **	-	Certification by Joyce M. Schuldt, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934.

32.1 # - Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350).

32.2 # - Certification by Joyce M. Schuldt, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350).

* Incorporated herein by reference to the specified prior filing by Pioneer Drilling Company.

** Filed herewith

\+ Management contract or compensatory plan or arrangement.

\# Furnished herewith

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.

PIONEER DRILLING COMPANY

/s/ Joyce M. Schuldt
Joyce M. Schuldt
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized Representative)

Dated: August 5, 2008

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**	Filed herewith
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#	Furnished herewith