UNIT CORP
Form 10-Q
May 03, 2007

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2007

OR

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

For the transition period from _________ to _________

[Commission File Number 1-9260]

UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000, Tulsa, Oklahoma	**74136**
(Address of principal executive offices)	(Zip Code)

(918) 493-7700
(Registrant's telephone number, including area code)

None
(Former name, former address and former fiscal year,
if changed since last report)

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

Yes [x]   No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

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

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

Yes [ ]   No [x]

As of May 1, 2007, 46,401,160 shares of the issuer's common stock were outstanding

FORM 10-Q
UNIT CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED)

	March 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 603	$ 589
Restricted cash	19	18
Accounts receivable	191,893	200,415
Materials and supplies	18,402	18,901
Other	11,312	13,017
Total current assets	222,229	232,940
Property and Equipment:		
Drilling equipment	828,730	781,190
Oil and natural gas properties, on the full cost method:		
Proved properties	1,394,270	1,330,010
Undeveloped leasehold not being amortized	59,774	53,687
Gas gathering and processing equipment	93,234	85,339
Transportation equipment	20,875	20,749
Other	18,092	17,082
	2,414,975	2,288,057
Less accumulated depreciation, depletion, amortization and impairment	778,921	735,394
Net property and equipment	1,636,054	1,552,663
Goodwill	57,524	57,524
Other Intangible Assets, Net	16,435	17,087
Other Assets	14,023	13,882
Total Assets	$ 1,946,265	$ 1,874,096

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2007	December 31, 2006
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 97,084	$ 92,125
Accrued liabilities	45,304	52,166
Income taxes payable	18,091	2,956
Contract advances	4,421	5,061
Current portion of other liabilities	10,037	8,634
Total current liabilities	174,937	160,942
Long-Term Debt	152,000	174,300
Other Long-Term Liabilities	55,680	55,741
Deferred Income Taxes	337,997	325,077
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	---	---
Common stock, $0.20 par value, 175,000,000 shares authorized, 46,399,260 and 46,283,990 shares issued, respectively	9,275	9,257
Capital in excess of par value	338,691	333,833
Accumulated other comprehensive income (loss)	(404)	1,339
Retained earnings	878,089	813,607
Total shareholders' equity	1,225,651	1,158,036
Total Liabilities and Shareholders' Equity	$ 1,946,265	$ 1,874,096

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In thousands except per share amounts)	
Revenues:		
Contract drilling	$ 160,285	$ 161,430
Oil and natural gas	86,106	94,326
Gas gathering and processing	30,768	25,482
Other	112	1,570
Total revenues	277,271	282,808
Expenses:		
Contract drilling:		
Operating costs	76,287	80,309
Depreciation	12,717	11,841
Oil and natural gas:		
Operating costs	22,139	18,306
Depreciation, depletion and amortization	29,347	24,182
Gas gathering and processing:		
Operating costs	27,501	22,801
Depreciation and amortization	2,339	1,150
General and administrative	5,182	3,966
Interest	1,641	990
Total expenses	177,153	163,545
Income Before Income Taxes	100,118	119,263
Income Tax Expense:		
Current	22,697	30,158
Deferred	12,939	14,192
Total income taxes	35,636	44,350
Net Income	$ 64,482	$ 74,913
Net Income per Common Share:		
Basic	$ 1.39	$ 1.62
Diluted	$ 1.39	$ 1.61

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 64,482	$ 74,913
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	44,617	37,340
Deferred tax expense	12,939	14,192
Other	2,379	1,492
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	8,522	16,614
Accounts payable	(15,877)	(20,177)
Materials and supplies inventory	499	(2,063)
Accrued liabilities	10,619	12,324
Contract advances	(640)	5,338
Other - net	1,166	876
Net cash provided by operating activities	128,706	140,849
Cash Flows From Investing Activities:		
Capital expenditures	(112,403)	(82,709)
Proceeds from disposition of assets	1,153	2,889
Other-net	(1)	(1,339)
Net cash used in investing activities	(111,251)	(81,159)
Cash Flows From Financing Activities:		
Borrowings under line of credit	22,100	21,500
Payments under line of credit	(44,400)	(76,200)
Proceeds from exercise of stock options	191	625
Book overdrafts	4,668	(5,741)
Net cash used in financing activities	(17,441)	(59,816)
Net Increase (Decrease) in Cash and Cash Equivalents	14	(126)
Cash and Cash Equivalents, Beginning of Year	589	947
Cash and Cash Equivalents, End of Period	$ 603	$ 821

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In thousands)	
Net Income	$ 64,482	$ 74,913
Other Comprehensive Income,		
Net of Taxes:		
Change in value of cash flow derivative instruments used as cash flow hedges (net of tax of $877 and $64)	(1,534)	224
Reclassification - derivative settlements (net of tax or $114 and $26)	(209)	(50)
Comprehensive Income	$ 62,739	$ 75,087

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited consolidated condensed financial statements include the accounts of Unit Corporation and its directly or indirectly wholly owned subsidiaries (company) and have been prepared under the rules and regulations of the Securities and Exchange Commission. As applicable under these regulations, certain information and footnote disclosures have been condensed or omitted and the consolidated condensed financial statements do not include all disclosures required by generally accepted accounting principles. In the opinion of the company, the unaudited consolidated condensed financial statements contain all adjustments necessary (all adjustments are of a normal recurring nature) to state fairly the interim financial information.

Results for the three months ended March 31, 2007 are not necessarily indicative of the results to be realized during the full year. The consolidated condensed financial statements should be read with the company's Annual Report on Form 10-K for the year ended December 31, 2006. With respect to the unaudited financial information of the company for the three month periods ended March 31, 2007 and 2006, included in this Form 10-Q, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated May 3, 2007 appearing herein, states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on that information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a "report" or a "part" of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Before January 1, 2006, Unit accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, Unit adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. Unit elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Financial statements for prior periods have not been restated. Upon adoption of FAS 123(R), Unit elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Staff Position No. FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards", issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification, will be recognized in the financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of Unit's business segments. Unit utilizes the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant.

In the first quarter of 2007, Unit recognized stock compensation expense for restricted stock awards and stock options of $0.6 million and capitalized stock compensation cost for oil and natural gas properties of $0.1 million. The tax benefit related to this stock based compensation was $0.2 million. In the first quarter of 2006, Unit recognized stock compensation expense for restricted stock awards and stock options of $0.6 million and capitalized stock compensation cost for oil and natural gas properties of $0.2 million. The tax benefit related to this stock based compensation was $0.2 million. The remaining unrecognized compensation cost related to unvested awards at March 31, 2007 is approximately $3.3 million with $0.6 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

No stock options or stock appreciation rights were granted during the first quarters of 2007 and 2006.

NOTE 2 - EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share for the company for the periods indicated.

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Three Months Ended March 31, 2007:			
Basic earnings per common share	$ 64,482	46,330	$ 1.39
Effect of dilutive stock options and grants	---	203	---
Diluted earnings per common share	$ 64,482	46,533	$ 1.39
For the Three Months Ended March 31, 2006:			
Basic earnings per common share	$ 74,913	46,200	$ 1.62
Effect of dilutive stock options	---	214	(0.01)
Diluted earnings per common share	$ 74,913	46,414	$ 1.61

At March 31, 2007, 33,000 outstanding stock options with an average exercise price of $61.40 were not included in the computation of diluted earnings per share because the option exercise prices were greater that the average market price of common shares. All stock options outstanding as of March 31, 2006 were included in the computation of diluted earnings per share for the three months ending March 31, 2006.

NOTE 3 - LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

As of March 31, 2007 and December 31, 2006, long-term debt consisted of the following:

	March 31, 2007	December 31, 2006
	(In thousands)	
Revolving Credit Facility, with Interest at March 31, 2007 and December 31, 2006 of 6.4%,	$ 152,000	$ 174,300
Less Current Portion	---	---
Total Long-Term Debt	$ 152,000	$ 174,300

The company has a $275.0 million revolving credit facility maturing on May 31, 2008. Borrowings under the credit facility are limited to a commitment amount, but the company may elect to have a smaller amount available. At March

31, 2007 the company has elected to have the full $275.0 million available as the commitment amount. The company is charged a commitment fee of .375 of 1% on the amount available but not borrowed. The company incurred origination, agency and syndication fees of $515,000 at the inception of the credit agreement $40,000 of which will be paid annually and the remainder of the fees amortized over the life of the agreement. During 2005 and 2006, in connection with its amendment of the credit agreement, the company incurred additional origination, agency and syndication fees of $187,500 and $60,000, respectively and these fees are being amortized over the remaining life of the agreement. The average interest rate for the first quarter of 2007 was 6.5%. At March 31, 2007 and April 27, 2007, borrowings were $152.0 million and $166.9 million, respectively.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. The latest redetermination supported a borrowing base of $375.0 million. Each re-determination is based primarily on a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. The determination of the company's borrowing base also includes an amount representing a small part of the value of the company's drilling rig fleet (limited to $20 million) as well as such loan value as the lenders reasonably attribute to Superior Pipeline Company's cash flow as defined in the credit agreement. The credit facility allows for one requested special re-determination of the borrowing base by either the banks or the company between each scheduled re-determination date.

At the company's election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which the LIBOR Rate option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At March 31, 2007, 145.6 million of the company's $152.0 million in borrowings were subject to the LIBOR rate.

The credit facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of the company's consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain limited exceptions, and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of the company's property, except in favor of the company's banks.

The credit facility also requires that the company have at the end of each quarter:

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On March 31, 2007, the company was in compliance with the covenants of the credit facility.

Other long-term liabilities consisted of the following:

	March 31, 2007	December 31, 2006
	(In thousands)	
Separation Benefit Plans	$ 3,752	$ 3,516
Deferred Compensation Plan	2,763	2,544
Retirement Agreement	1,224	1,386
Workers' Compensation	22,643	22,157
Gas Balancing Liability	1,080	1,080
Plugging Liability	34,255	33,692
	65,717	64,375
Less Current Portion	10,037	8,634
Total Other Long-Term Liabilities	$ 55,680	$ 55,741

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning April 1, 2007 through 2011 are $10.0 million, $157.0 million, $1.9 million, $2.1 million and $2.5 million. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at March 31, 2007 approximates its fair value.

NOTE 4 - ASSET RETIREMENT OBLIGATIONS

Under FAS 143, "Accounting for Asset Retirement Obligations" (FAS 143) the company must record the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas properties which require cash to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The company does not have any assets restricted for the purpose of settling these plugging liabilities.

The following table shows the activity for the three months ending March 31, 2007 and 2006 relating to the company's retirement obligation for plugging liability:

	Three Months Ended March 31, 2007	2006
	(In thousands)	
Plugging Liability, January 1	$ 33,692	$ 22,015
Accretion of Discount	434	310
Liability Incurred	325	323
Liability Settled	(331)	(18)
Revision of Estimates	135	6,968
Plugging Liability, March 31	34,255	29,598
Less Current Portion	1,091	477
Total Long-Term Plugging Liability	$ 33,164	$ 29,121

NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the Financial Accounting Standards Board (“FASB“) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company adopted the provisions of FIN 48 effective January 1, 2007. The adoption of FIN 48 had no material effect on the company's results of operations or financial condition.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation".) which became effective for us on January 1, 2007. According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies." In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

Because the provisions of EITF 06-3 require only the presentation of additional disclosures, the adoption of EITF 06-3 did not have an effect on the company's statements of income, financial condition or cash flows. The company collects sales and use tax when it sells used equipment or rents drilling equipment to third parties. The sales and use tax is reported net. Gross production taxes associated with the sale of oil and natural gas production is reported gross and was $5.7 million for the three months ended March 31, 2007 and 2006, respectively.

In September 2006, the FASB issued FAS No. 157, “Fair Value Measurements” (FAS 157). FAS 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. The company is currently assessing the impact of FAS 157 on its statement of income, financial condition and cash flows.

In February 2007, the FASB issued FAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115”, (FAS 159) which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. The company is currently assessing the impact of FAS 159 on its statement of income, financial condition and cash flows.

NOTE 6 - HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to the fluctuations in the prices it receives for its oil and natural gas production. These instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists.

In January and February of 2007, the company entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.00 and a ceiling of $10.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.25 and a ceiling of $9.25
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

In December 2006, the company entered into the following natural gas hedging transaction.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	January through December of 2007
Prices	Floor of $6.00 and a ceiling of $9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

All of the hedges for 2007 are cash flow hedges and there is no material amount of ineffectiveness. The fair value of these three hedge transactions was recognized on the March 31, 2007 balance sheet as current derivative liability totaling $1.2 million and a loss of $0.8 million, net of tax, in accumulated other comprehensive income.

In February 2005, the company entered into an interest rate swap to help manage its exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, the company’s interest expense was decreased by $0.2 million in the first quarter of 2007 and $0.1 million in the first quarter of 2006. The fair value of the swap was recognized on the March 31, 2007 balance sheet as a current derivative asset totaling $0.5 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

NOTE 7 - INDUSTRY SEGMENT INFORMATION

The company has three business segments:

. Contract Drilling,
. Oil and Natural Gas and
. Mid Stream

These three segments represent the company's three main business units offering different products and services. The Contract Drilling segment is engaged in the land contract drilling of oil and natural gas wells, the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the Mid-Stream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

The company evaluates the performance of these operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. The company has natural gas production in Canada, which is not significant. Information regarding the company's operations by segment for the three month periods ended March 31, 2007 and 2006 is as follows:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(In thousands)	
Revenues:		
Contract drilling	$ 168,813	$ 167,682
Elimination of inter-segment revenue	8,528	6,252
Contract drilling net of inter-segment revenue	160,285	161,430
Oil and natural gas	86,106	94,326
Gas gathering and processing	33,931	29,238
Elimination of inter-segment revenue	3,163	3,756
Gas gathering and processing net of inter-segment revenue	30,768	25,482
Other (1)	112	1,570
Total revenues	$ 277,271	$ 282,808
Operating Income (2):		
Contract drilling	$ 71,281	$ 69,280
Oil and natural gas	34,620	51,838
Gas gathering and processing	928	1,531
Total operating income	106,829	122,649
General and administrative expense	(5,182)	(3,966)
Interest expense	(1,641)	(990)
Other income - net	112	1,570
Income before income taxes	$ 100,118	$ 119,263

(1) Includes a $1.0 million gain from insurance proceeds on the loss of a drilling rig from a blow out and fire in January 2006.

(2) Operating income is total operating revenues less operating expenses, depreciation, depletion and amortization and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

REPORT OF INDEPENDENT
REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and its subsidiaries as of March 31, 2007, and the related consolidated condensed statements of income and comprehensive income for each of the three month periods ended March 31, 2007 and 2006 and the consolidated condensed statements of cash flows for the three month periods ended March 31, 2007 and 2006. These interim financial statements are the responsibility of the company's management.

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

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated condensed interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2006, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended (not presented herein), management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2006 and the effectiveness of the company's internal control over financial reporting as of December 31, 2006; and in our report dated March 1, 2007, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated condensed balance sheet as of December 31, 2006, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 3, 2007

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

FINANCIAL CONDITION

Management's Discussion and Analysis (MD&A) provides an understanding of operating results and financial condition by focusing on changes in key measures from year to year. MD&A is organized in the following sections:

- Financial Condition
- New Accounting Pronouncements
- Results of Operations

MD&A should be read in conjunction with the Consolidated Condensed Financial Statements and related notes included in this report.

Summary. Our financial condition and liquidity depends on the cash flow from our three principal business segments (and our subsidiaries that carry out those operations) and borrowings under our bank credit agreement.

Our cash flow is influenced mainly by:

- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil production;
- the quantity of natural gas and oil we produce;
- the demand for and the dayrates we receive for our drilling rigs; and
- the margins we obtain from our natural gas gathering and processing contracts.

Our three principal business segments are:

- land contract drilling carried out by our subsidiary Unit Drilling Company and its subsidiary Unit Texas Drilling, L.L.C.;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company and its subsidiaries; and
- mid stream operations (consisting of natural gas buying, selling, gathering and processing) carried out by our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information as of March 31, 2007 and 2006 and for the three months ended March 31, 2007 and 2006:

	March 31, 2007	March 31, 2006	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 47,292	$ 44,242	7 %
Long-Term Debt	$ 152,000	$ 90,300	68%
Shareholders' Equity	$ 1,225,651	$ 913,411	34%
Ratio of Long-Term Debt to Total Capitalization	11%	9%	22%

Net Income	$	64,482	$	74,913	(14)%
Net Cash Provided by Operating Activities	$	128,706	$	140,849	(9)%
Net Cash Used in Investing Activities	$	(111,251)	$	(81,159)	37%
Net Cash Used In Financing Activities	$	(17,441)	$	(59,816)	(71)%

The following table summarizes certain operating information for the three months ended March 31, 2007 and 2006:

	March 31, 2007	March 31, 2006	Percent Change
Oil Production (MBbls)	356	327	9%
Natural Gas Production (MMcf)	10,673	10,713	---%
Average Oil Price Received	$ 47.59	$ 54.53	(13)%
Average Oil Price Received Excluding Hedges	$ 47.59	$ 54.53	(13)%
Average Natural Gas Price Received	$ 6.37	$ 7.04	(10)%
Average Natural Gas Price Received Excluding Hedges	$ 6.36	$ 7.04	(10)%
Average Number of Our Drilling Rigs in Use During the Period	96.8	108.6	(11)%
Total Number of Drilling Rigs Available at the End of the Period	118	111	6%
Average Dayrate	$ 19,427	$ 17,122	13%
Gas Gathered—MMBtu/day	226,081	215,341	5%
Gas Processed—MMBtu/day	43,327	30,668	41%
Number of Active Natural Gas Gathering Systems	37	36	3%

At March 31, 2007, we had unrestricted cash totaling $0.6 million and we had borrowed $152.0 million of the $275.0 million we have available under our credit agreement.

Our Credit Facility. At March 31, 2007, we had a $275 million revolving credit facility maturing on May 31, 2008. Borrowings under the credit facility are limited to a commitment amount, but we may elect to have a smaller amount available. At March 31, 2007, we had elected to have the full $275.0 million available as the commitment amount. We are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We incurred origination, agency and syndication fees of $515,000 at the inception of the agreement, $40,000 of which will be paid annually and the remainder of the fees amortized over the life of the agreement. During 2005 and 2006, we incurred additional origination; agency and syndication fees of $187,500 and $60,000, respectively while amending the credit facility and these fees are being amortized over the remaining life of the agreement. The average interest rate for the first quarter of 2007 was 6.5%. At March 31, 2007 and April 27, 2007, our borrowings were $152.0 million and $166.9 million, respectively.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. The latest redetermination supported a borrowing base of $375.0 million. Each re-determination is based primarily on a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. The determination of our borrowing base also includes an amount representing a small part of the value of our drilling rig fleet (limited to $20 million) as well as such loan value as the lenders reasonably attribute to Superior Pipeline Company's cash flow as defined in the credit agreement. The credit facility allows for one requested special re-determination of the borrowing base by either the banks or us between each scheduled re-determination date.

At our election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which such LIBOR Rate option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At March 31, 2007, $145.6 million of the $152.0 million we had borrowed was subject to the LIBOR rate.

The credit facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain limited exceptions, and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our banks.

The credit facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On March 31, 2007, we were in compliance with the covenants in the credit facility.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was decreased by $0.2 million in the first quarter of 2007. The fair value of the swap was recognized on the March 31, 2007 balance sheet as current derivative assets totaling $0.5 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At March 31, 2007, we have the following contractual obligations:

	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Bank Debt (1)	$ 161,989	$ 8,558	$ 153,431	$ ---	$ ---
Retirement Agreements (2)	1,224	726	498	---	---
Operating Leases (3)	4,488	1,446	2,583	459	---
Drill Pipe and Drilling Components (4)	33,195	33,195	---	---	---
SerDrilco Inc. Earn-Out Agreement (5)	17,866	17,866	---	---	---
Total Contractual Obligations	$ 218,762	$ 61,791	$ 156,512	$ 459	$ ---

(1) See the previous discussion in MD&A regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated at the March 31, 2007 interest rate

of 6.4% including the effect of the interest rate swap related to $50.0 million of the outstanding debt.

(2) In the second quarter of 2001, we recorded $1.3 million in employee benefit expense for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $25,000 through June 2009. In the first quarter of 2004, we assumed a liability for the present value of a separation agreement between PetroCorp Incorporated

and one of its previous officers. The liability associated with this agreement will be paid in quarterly payments of $12,500 through December 31, 2007. In the first quarter of 2005, we recorded $0.7 million in employee benefit expense for the present value of a separation agreement made in connection with the retirement of John Nikkel from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, will be paid in monthly payments of $31,250 starting in November 2006 and continuing through October 2008. These liabilities as presented above are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; and Denver, Colorado under the terms of operating leases expiring through January 31, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess rig equipment and production inventory.

(4) Due to the potential for limited availability of new drill pipe within the industry, we have committed to purchase approximately $30.7 million of drill pipe and drill collars. We have also committed to purchase $3.1 million of rig components with 20% or $0.6 million paid through March 31, 2007.

(5) On December 8, 2003, the company acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest, L.L.C., for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to receive one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. For the year ending December 31, 2006, the third and final year of the earn-out period, the drilling rigs included in the earn-out provision had cash flow providing an earn-out of $17.9 million which was paid in April 2007.

At March 31, 2007, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	**Total Amount Committed Or Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Deferred Compensation Plan (1)	$ 2,763	Unknown	Unknown	Unknown	Unknown
Separation Benefit Plans (2)	$ 3,752	$ Unknown	Unknown	Unknown	Unknown
Plugging Liability (3)	$ 34,255	$ 1,091	$ 2,262	$ 3,079	$ 27,823
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 22,643	$ 8,220	$ 4,182	$ 1,505	$ 8,736

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our consolidated condensed balance sheet, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or

involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit

Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. At March 31, 2007, there were 33 eligible employees participating in the plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143), we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for certain properties where we believe there are insufficient oil and natural gas reserves available to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2007, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $7,000, $4,000 and $14,000 in 2006, 2005 and 2004, respectively and have not had any repurchases in 2007.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

Hedging**.** Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

In January and February of 2007, we entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.00 and a ceiling of $10.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.25 and a ceiling of $9.25
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

In December 2006, we entered into the following natural gas hedging transaction.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	January through December of 2007
Prices	Floor of $6.00 and a ceiling of $9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East - Inside FERC

All of the hedges for 2007 are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the hedge these three hedge transactions was recognized on the March 31, 2007 balance sheet as current derivative liability totaling $1.2 million and a loss of $0.8 million, net of tax, in accumulated other comprehensive income.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was decreased by $0.2 million in the first quarter of 2007 and $0.1 million in the first quarter of 2006. The fair value of the swap was recognized on the March 31, 2007 balance sheet as current derivative assets totaling $0.5 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.5 million for Oklahoma workers' compensation to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas**.** Natural gas comprises approximately 85% of our total oil and natural gas reserves. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our first quarter 2007 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $337,000 per month ($4.0 million annualized) change in our pre-tax operating cash flow. Our first quarter 2007 average natural gas price was $6.37 compared to an average natural gas price of $7.04 for the first quarter of 2006. A $1.00 per barrel change in our oil price would have a $112,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow based on our production in the first quarter of 2007. Our first quarter 2007 average oil price was $47.59 compared with an average oil price of $54.53 received in the first quarter of 2006.

Because oil and natural gas prices have such a significant affect on the value of our oil and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely effect the semi-annual determination of the amount available for us to borrow under our bank credit facility since that determination is based mainly on the value of our oil and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Most of our natural gas production is sold to third parties under month-to-month contracts.

<u>Oil and Natural Gas Acquisitions and Capital Expenditures</u>. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We drilled 54 wells (22.95 net wells) in the first quarter of 2007 compared to 41 wells (10.84 net wells) in the first quarter of 2006. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first quarter of 2007 totaled $70.4 million. Based on current prices, we plan to drill an estimated 270 wells in 2007 and estimate our total capital expenditures for oil and natural gas exploration to be approximately $326.0 million. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, the weather and the efforts of outside industry partners.

On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition were all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our rigs and our ability to supply the equipment needed.

Although rig utilization declined in the fourth quarter of 2006 and into the first quarter of 2007, we do not anticipate declines in labor cost per hour due to the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future technological requirements of the drilling industry. To help keep qualified labor, we previously implemented longevity pay incentives and as recently as the second quarter of 2006 provided pay increases in some of our operating districts. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs strengthens above the first quarter levels of 83%, shortages of experienced personnel may limit our ability to operate our drilling rigs.

We currently do not have any shortages of drill pipe and drilling equipment. Because of the potential for shortages in the availability of new drill pipe, at March 31, 2007 we have commitments to purchase approximately $30.7 million of drill pipe and drill collars in 2007. We have also committed to purchase $3.1 million of rig components with 20% or $0.6 million paid through March 31, 2007.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we can charge for our contract drilling services. In March 2007, our average dayrate for the 118 drilling rigs that we owned was $19,028 with an 83% utilization rate. In the first quarter of 2007 our average dayrate was $19,427 per day compared to $17,122 in the first quarter of 2006. The average number of drilling rigs used was 96.8 (83%) in the first quarter of 2007 compared to 108.6 (98%) in the first quarter of 2006. Based on the average utilization of our drilling rigs during the first quarter of 2007, a $100 per day change in dayrates has a $9,680 per day ($3.5 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first quarter of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with high levels of natural gas storage throughout the majority of the winter season. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties for comparable type projects. During the first quarter of 2007 and 2006, we drilled 17 and 13 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $4.5

million and $3.2 million during the first quarter of 2007 and 2006, respectively, reduced the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Drilling Acquisitions and Capital Expenditures. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig was modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May we began moving a 1,500 horsepower drilling rig to our Rocky Mountain Division following completion of its construction in the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the rigs. An additional $3.0 million of modifications were made to the rigs before the rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain Division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

During 2006 we paid $4.5 million for the purchase of major components to construct two 1,500 horsepower drilling rigs. The first rig was being moved to the Rocky Mountain division at the end of March 2007 and was constructed for approximately $9.6 million. The second rig should be placed in service in the second quarter of 2007.

For our contract drilling operations, during the first quarter of 2007, we incurred $49.2 million in capital expenditures. For the year 2007, we have budgeted capital expenditures of approximately $131.0 million.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates four natural gas treatment plants, six operating processing plants, 37 active gathering systems and 614 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas and has been in business since 1996. This subsidiary enhances our ability to gather and market not only our own natural gas but also that owned by third parties and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During the first quarter of 2007, Superior purchased $1.9 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $1.3 million. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas exploration operations has been eliminated in our consolidated condensed financial statements. In the first quarter of 2006, we eliminated intercompany revenues of $2.5 million of natural gas and $1.3 million of natural gas liquids.

Mid-Stream Acquisitions. In September 2006, we closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company's statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

During the first quarter of 2007, Superior incurred $7.9 million in capital expenditures compared to $4.1 million for the same period in 2006. For 2007, we have budgeted capital expenditures of approximately $25.0 million for Superior. Our focus is on growing this segment through the construction of new facilities or acquisitions.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 12 oil and natural gas limited partnerships which were formed privately and publicly. Each partnership's revenues and costs are shared under formulas prescribed in its limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2006, the total paid to us for all of these fees was $1.3 million and we expect the amount to approximately be the same in 2007. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated condensed financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the Financial Accounting Standards Board (“FASB“) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted the provisions of FIN 48 effective January 1, 2007. The adoption of FIN 48 had no material effect on our results of operations of financial condition.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation".) which became effective for us on January 1, 2007. According to the provisions of EITF 06-3:

· taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

· that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies." In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

Because the provisions of EITF 06-3 require only the presentation of additional disclosures, the adoption of EITF 06-3 did not have an effect on our statements of income, financial condition or cash flows. We collect sales and use tax when we sell used equipment or rent drilling equipment to third parties. The sales and use tax is reported net. Gross production taxes associated with the sale of oil and natural gas production is reported gross and was $5.7 million for the three months ending March 31, 2007 and 2006, respectively.

In September 2006, the FASB issued FAS No. 157, “Fair Value Measurements” (FAS 157). FAS 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of FAS 157 on our statement of income, financial condition and cash flows.

In February 2007, the FASB issued FAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115”, (FAS 159) which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We are currently assessing the impact of FAS 159 on our statement of income, financial condition and cash flows.

RESULTS OF OPERATIONS

Quarter Ended March 31, 2007 versus Quarter Ended March 31, 2006

Provided below is a comparison of selected operating and financial data for the first quarter of 2007 versus the first quarter of 2006:

		Quarter Ended March 31, 2007		Quarter Ended March 31, 2006	Percent Change
Total Revenue	$	277,271,000	$	282,808,000	(2)%
Net Income	$	64,482,000	$	74,913,000	(14)%
Drilling:					
Revenue	$	160,285,000	$	161,430,000	(1)%
Operating costs excluding depreciation	$	76,287,000	$	80,309,000	(5)%
Percentage of revenue from daywork contracts		100%		100%	
Average number of rigs in use		96.8		108.6	(11)%
Average dayrate on daywork contracts	$	19,427	$	17,122	13%
Depreciation	$	12,717,000	$	11,841,000	7%
Oil and Natural Gas:					
Revenue	$	86,106,000	$	94,326,000	(9)%
Operating costs excluding depreciation, depletion and amortization	$	22,139,000	$	18,306,000	21%
Average natural gas price (Mcf)	$	6.37	$	7.04	(10)%
Average oil price (Bbl)	$	47.59	$	54.53	(13)%
Natural gas production (Mcf)		10,673,000		10,713,000	---%
Oil production (Bbl)		356,000		327,000	9%
Depreciation, depletion and amortization rate (Mcfe)	$	2.28	$	1.90	20%
Depreciation, depletion and amortization	$	29,347,000	$	24,182,000	21%
Mid-Stream Operations:					
Revenue	$	30,768,000	$	25,482,000	21%
Operating costs excluding depreciation and amortization	$	27,501,000	$	22,801,000	21%
Depreciation and amortization	$	2,339,000	$	1,150,000	103%
Gas gathered - MMbtu/day		226,081		215,341	5%
Gas processed - MMbtu/day		43,327		30,668	41%
General and Administrative Expense	$	5,182,000	$	3,966,000	31%
Interest Expense	$	1,641,000	$	990,000	66%
Income Tax Expense	$	35,636	$	44,350	(20)%
Average Interest Rate		6.08%		5.41%	12%
Average Long-Term Debt Outstanding	$	164,451,000	$	113,599,000	45%

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first quarter of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with the high levels of natural gas storage throughout the majority of the winter season. Drilling revenues decreased $1.1 million or

1% in the first quarter of 2007 versus the first quarter of 2006. After the first quarter of 2006, we constructed six drilling rigs. Four of these additional drilling rigs provided contract drilling services in the first quarter of 2007 increasing drilling revenues by $6.8 million or 4%. Revenues for rigs previously owned declined $7.9 million or 5% from revenues achieved in the first quarter of 2006 and more than offset the revenue from rigs added subsequent to the first quarter of 2006. Average rig utilization declined from 108.6 rigs in the first quarter of 2006 to 96.8 in the first quarter of 2007. The decline in rig utilization decreased drilling revenues by $17.6 million while increases in dayrates between the comparative first quarters provided additional revenue of $16.5 million partially offsetting utilization decreases. Our average dayrate in the first quarter of 2007 was 13% higher than in the first quarter of 2006. Demand for our drilling rigs is anticipated to remain at approximately 85% in the short term. With decreases in drilling rig demand, we experienced a 2% decline in the first quarter 2007 average dayrate compared to the fourth quarter 2006 average dayrate and we expect similar decreases in average dayrates to continue into the second quarter.

Drilling operating costs decreased $4.0 million or 5% between the comparative quarters. Total operating cost declined $8.8 million due to decreased drilling rig utilization, but was partially offset by increases in operating cost per day of $544 or $4.8 million in total for the quarter. A majority of the increase in cost per day was attributable to increases in labor cost both directly and indirectly related to the drilling of wells. Although rig utilization has declined, we do not anticipate declines in labor cost per hour due to the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future technological requirements of the drilling industry. We did not drill any turnkey or footage wells in first quarter of 2007 or 2006. Contract drilling depreciation increased $0.9 million or 7%. The addition of the six drilling rigs placed in service since the first quarter of 2006 increased depreciation $0.5 million or 5% with the remainder of the increase attributable to depreciation on capitalized refurbishments of rigs throughout 2006 partially offset by less depreciation expense due to lower utilization.

Oil and natural gas revenues decreased $8.2 million or 9% in the first quarter of 2007 as compared to the first quarter of 2006. Decreased oil and natural gas prices accounted for a decrease of $9.0 million in oil and natural gas revenues while increased equivalent natural gas production volumes accounted for $0.8 million in offsetting revenue increases. In the first quarter of 2007, oil production increased by 9% while natural gas production decreased less than one half of 1%. We experienced a 9% decrease in oil production and a 10% decrease in natural gas production compared to the fourth quarter of 2006. Comparative first quarter increased oil production came primarily from our ongoing development drilling activity prior to 2007 while oil and natural gas production decreases between the first quarter and fourth quarter were primarily due to the impact from a Texas refinery fire, adverse winter weather, pipeline construction delays preventing the connection of wells recently drilled, the timing of completion of certain wells and declining production curves on previously drilled wells. We are forecasting an increase of 6% to 10% in total production for 2007 compared to 2006. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $3.8 million or 21% in the first quarter of 2007 as compared to 2006. An increase in the average cost per equivalent Mcf produced represented 96% of the increase in production costs with the remaining 4% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 80% of the increase, general and administrative costs directly related to oil and natural gas production represented 17% and the remainder resulted from increases in the accretion of plugging liability. Lease operating expenses per Mcfe increased 27% between the comparative quarters as post production transportation cost and compression increased along with a 43% increase in workover cost. General and administrative expenses increased as labor costs increased primarily due to a 13% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization ("DD&A") increased $5.2 million or 21%. Higher production volumes accounted for 5% of the increase while increases in our DD&A rate represented 95% of the increase. The increase in our DD&A rate in the first quarter of 2007 compared to the first quarter of 2006 resulted primarily from an 18% increase in our finding cost in 2006 and continued increases in our finding cost into the first quarter of 2007. Demand for drilling rigs throughout our areas of exploration in the first three quarters of 2006 have increased the dayrates we pay to drill wells in our developmental program and the higher oil and natural gas prices received in 2005 and much of 2006 has caused increased sales prices for producing property acquisitions. We do believe there continues to be economical opportunities for acquisitions given the volatility of commodity prices.

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate four natural gas treatment plants and own six operating processing plants, 37 active gathering systems and 614 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Intercompany revenue from services and purchases of production between our natural gas gathering and processing segment and our oil and natural gas segments has been eliminated. Our mid-stream revenues were $5.3 million or 21% higher in the first quarter of 2007 as compared to the first quarter of 2006 due to the higher volumes transported, processed and sold. The average price for gas sold was down 12% and the average price for liquids sold was down 10% partially offsetting the increase in revenue due to volume increases. Gas gathering volumes per day in the first quarter 2007 were 5% higher as compared to the first quarter of 2006 while gas processing volumes per day increased 41%. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and to a lesser extent volumes from wells added to existing systems throughout 2006. Operating costs increased 21% in the first quarter of 2007 compared with the first quarter of 2006 due an 13% increase in prices paid for natural gas purchased, a 103% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas transported and a 31% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 42%. The 103% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Gas gathering volumes per day in the first quarter of 2007 were down 11% compared to the fourth quarter of 2006 primarily due to a slow down of new well connections associated with adverse winter weather and pipeline construction delays. Subsequent declines will continue until further field development results in new well connections. Gas processing volumes per day in the first quarter of 2007 were down 3% compared to the fourth quarter of 2006 due to production declines on new wells added during the fourth quarter of 2006 at one processing system.

General and administrative expense increased $1.2 million or 31% between the comparative quarters. The increase was primarily from a 17% increase in the number of employees associated with the growth of the company and increases in employee compensation cost.

Total interest expense increased 66% between the comparative quarters. Average debt outstanding was higher in the first quarter of 2007 as compared to the first quarter of 2006 primarily due to acquisitions made in the last four months of 2006. Average debt outstanding accounted for approximately 71% of the interest expense increase, with the remaining 29% resulting from an increase in average interest rates on our bank debt. A reduction in interest expense of $0.2 million in the first quarter of 2007 as compared to a reduction of $0.1 million in the first quarter of 2006 from the settlement of the interest rate swap partially offset outstanding debt and rate increases. Associated with our increased level of development of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $1.0 million of interest in the first quarter of 2007 compared with $0.7 million in the first quarter of 2006.

Income tax expense decreased $8.7 million or 20% due primarily to the decrease in income before income taxes. Our effective tax rate for the first quarter of 2007 was 35.6% versus 37.1% in the first quarter of 2006 due primarily to the increase in the manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense was $22.7 million or 64% of total income tax expense in the first quarter of 2007 as compared to $30.2 million or 68% of total income tax expense in the first quarter of 2006. Income taxes paid in the first quarter of 2007 were $8.0 million.

In January 2006, one of our drilling rigs was destroyed by a fire. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss exceeded our net book value and provided a gain of approximately $1.0 million which is recorded in other revenues.

SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts” a similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- the estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations; and
- demand for our drilling rigs and drilling rig rates.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

Our operations are exposed to market risks primarily as a result of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first three months of 2007 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $337,000 per month ($4.0 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have an $112,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow.

In an effort to try and reduce the impact of price fluctuations, over the past several years we have periodically used hedging strategies to hedge the price we will receive for a portion of our future oil and natural gas production. A detailed explanation of those transactions has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. Historically, we have not used any financial instruments, such as interest rate swaps, to manage our exposure to possible increases in interest rates. However, in February 2005, we entered into an interest rate swap for $50.0 million of our outstanding debt to help manage our exposure to any future interest rate volatility. A detailed explanation of this transaction has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above. Based on our average outstanding long-term debt subject to the floating rate in the first three months of 2007, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $1.1 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures are effective as of March 31, 2007 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer and management to allow timely decisions.

Changes in Internal Controls. There were no changes in the company's internal controls over financial reporting during the quarter ended March 31, 2007 that could significantly affect these internal controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2006, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2006.

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

Not applicable

Item 3. Defaults Upon Senior Securities

Not applicable

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

Not applicable

Item 5. Other Information

Not applicable

Item 6. Exhibits

Exhibits:

15	Letter re: Unaudited Interim Financial Information.
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Unit Corporation

Date: May 3, 2007	By:/s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: May 3, 2007	By:/s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer