UNIT CORP
Form 10-Q
May 05, 2006

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, 2006

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, 2006, 46,257,646 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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 821	$ 947
Restricted cash	1,018	268
Accounts receivable	182,081	199,765
Materials and supplies	16,171	14,108
Other	7,847	8,597
Total current assets	207,938	223,685
Property and Equipment:		
Drilling equipment	659,748	626,913
Oil and natural gas properties, on the full cost method:		
Proved properties	1,044,743	995,119
Undeveloped leasehold not being amortized	38,604	38,421
Gas gathering and processing equipment	64,268	60,354
Transportation equipment	18,219	17,338
Other	13,757	12,935
	1,839,339	1,751,080
Less accumulated depreciation, depletion, amortization and impairment	611,889	575,410
Net property and equipment	1,227,450	1,175,670
Goodwill	39,659	39,659
Other Assets	18,106	17,181
Total Assets	$ 1,493,153	$ 1,456,195

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, 2006	December 31, 2005
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 84,409	$ 109,621
Accrued liabilities	29,682	32,819
Income taxes payable	32,625	16,941
Contract advances	10,886	5,548
Current portion of other liabilities	6,094	7,583
Total current liabilities	163,696	172,512
Long-Term Debt	90,300	145,000
Other Long-Term Liabilities	51,781	41,981
Deferred Income Taxes	273,965	259,740
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	---	---
Common stock, $.20 par value, 75,000,000 shares authorized, 46,257,646 and 46,178,162 shares issued, respectively	9,242	9,236
Capital in excess of par value	327,167	328,037
Accumulated other comprehensive income	659	485
Unearned compensation - restricted stock	---	(2,226)
Retained earnings	576,343	501,430
Total shareholders' equity	913,411	836,962
Total Liabilities and Shareholders' Equity	$ 1,493,153	$ 1,456,195

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, 2006	Three Months Ended March 31, 2005
	(In thousands except per share amounts)	
Revenues:		
Contract drilling	$ 161,430	$ 96,681
Oil and natural gas	94,326	56,864
Gas gathering and processing	25,482	18,230
Other	1,570	(195)
Total revenues	282,808	171,580
Expenses:		
Contract drilling:		
Operating costs	80,309	63,431
Depreciation	11,841	9,610
Oil and natural gas:		
Operating costs	18,306	12,413
Depreciation, depletion and amortization	24,182	14,432
Gas gathering and processing:		
Operating costs	22,801	16,834
Depreciation	1,150	638
General and administrative	3,966	3,971
Interest	990	687
Total expenses	163,545	122,016
Income Before Income Taxes	119,263	49,564
Income Tax Expense:		
Current	30,158	9,417
Deferred	14,192	9,417
Total income taxes	44,350	18,834
Net Income	$ 74,913	$ 30,730
Net Income per Common Share:		
Basic	$ 1.62	$ 0.67
Diluted	$ 1.61	$ 0.67

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, 2006	2005
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 74,913	$ 30,730
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	37,340	24,874
Deferred tax expense	14,192	9,417
Other	1,492	1,246
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	16,614	(10,448)
Accounts payable	(20,177)	(10,781)
Materials and supplies inventory	(2,063)	(1,078)
Accrued liabilities	12,324	13,277
Contract advances	5,338	(1,145)
Other - net	876	(198)
Net cash provided by operating activities	140,849	55,894
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including drilling rig acquisitions)	(82,709)	(47,121)
Proceeds from disposition of assets	2,889	2,328
Other-net	(1,339)	(207)
Net cash used in investing activities	(81,159)	(45,000)
Cash Flows From (Used In) Financing Activities:		
Borrowings under line of credit	21,500	26,400
Payments under line of credit	(76,200)	(43,900)
Net change in other long-term liabilities	---	276
Proceeds from exercise of stock options	625	517
Book overdrafts	(5,741)	5,618
Net cash from financing activities	(59,816)	(11,089)
Net Decrease in Cash and Cash Equivalents	(126)	(195)
Cash and Cash Equivalents, Beginning of Year	947	665
Cash and Cash Equivalents, End of Period	$ 821	$ 470

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,	
	2006	2005
	(In thousands)	
Net Income	$ 74,913	$ 30,730
Other Comprehensive Income, Net of Taxes:		
Change in value of cash flow derivative instruments used as cash flow hedges	224	(1,464)
Reclassification - derivative settlements	(50)	28
Comprehensive Income	$ 75,087	$ 29,294

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, 2006 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, 2005. With respect to the unaudited financial information of the company for the three month periods ended March 31, 2006 and 2005, 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 5, 2006 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, the company 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.

In the first quarter of 2006, the company adopted Financial Accounting Standards (FAS) No. 123(R) "Share-Based Payment", which revises FAS 123, "Accounting for Stock-Based Compensation." Under FAS 123(R), the company is required to select a valuation technique or option-pricing model that meets the criteria as stated in that standard, which includes a binomial model and the Black-Scholes model. The company has elected to use the Black-Scholes model. At the adoption of FAS 123(R) the company elected to use the "modified prospective method" as defined in the standard. This method requires the company to value stock options before its adoption of FAS123(R) at the grant-date fair value estimated in accordance with FAS 123, and expense these amounts over the stock options remaining vesting period. This resulted in the company expensing $0.2 million in the contract drilling segment, $0.2 million in the oil and natural gas segment and $0.2 million to corporate general and administrative expense, for a total of $0.6 million, in the first quarter of 2006 and capitalized as part of geological and geophysical cost of $0.2 million. On March 29, 2005, the SEC published Staff Accounting Bulletin (SAB) 107, which provides the staff's views on a variety of matters relating to stock-based payments. SAB 107 requires stock-based compensation be classified in the same line items as cash compensation. Results for prior periods have not been restated. Under the provisions of FAS 123(R) deferred compensation associated with the restricted compensation grants is no longer reflected in the consolidated condensed balance sheet. Accordingly, a corresponding decrease to additional paid in capital of $2.2 million has been recorded.

The following table illustrates for the three month period ending March 31, 2005 the effect on net income and earnings per share if the company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation. Compensation expense included in reported net income before January 1, 2006 is the company's matching 401(k) contribution.

		Three Months Ended March 31, 2005 (In thousands except per share amounts)
Net Income, as Reported	$	30,730
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax		549
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards		(1,030)
Pro Forma Net Income	$	30,249
Basic Earnings per Share:		
As reported	$	0.67
Pro forma	$	0.66
Diluted Earnings per Share:		
As reported	$	0.67
Pro forma	$	0.66

In the first quarter of 2006, the company recognized stock compensation cost of $0.6 million and capitalized stock compensation cost for oil and natural gas properties of $0.2 million. The remaining unrecognized compensation cost related to unvested awards at March 31, 2006 is approximately $3.9 million with $1.0 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is one year.

The following table estimates the fair value of each option granted during the three month periods ending March 31, 2006 and 2005 using the Black-Scholes model applying the estimated values presented in the table:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Options Granted	---	4,000
Estimated Fair Value (In Millions)	---	$ 0.1
Estimate of Stock Volatility	---	0.55
Estimated Dividend Yield	---	0%
Risk Free Interest Rate	---	4.42%
Expected Life Range Based on Prior Experience (In Years)	---	1 to 10

Expected volatilities are based on the historical volatility of the company's stock. The company uses historical data to estimate option exercise and employee termination rates within the model and aggregates groups of employees that have similar historical exercise behavior for valuation purposes. The company has historically not paid dividends on its stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan (“the Plan”). Under the Plan 330,950 shares of common stock were reserved for issuance. On May 3, 1995, the company's shareholders approved and amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the Plan. Under the terms of the Plan, awards may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in installments subject to certain restrictions. No shares were issued under the Plan in 2003 and 2004. On December 13, 2005, 38,190 shares in the form of restricted stock awards were granted under the Plan at the New York Stock Exchange closing price of $58.30. Half of the shares granted will vest on January 1, 2007, and the second half will vest on January 1, 2008. Receipt of these shares is contingent on the recipients remaining employed by the company.

The company also has a Stock Option Plan (the “Option Plan”), which provides for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The Option Plan permits the issuance of qualified or nonqualified stock options. Options granted typically become exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares Three Months Ended March 31, 2006	Number of Shares Three Months Ended March 31, 2005	Weighted Average Exercise Price 2006	Weighted Average Exercise Price 2005
Outstanding at Beginning of Period	434,713	553,750	$ 24.14	$ 22.11
Granted	---	4,000	---	34.78
Exercised	(29,043)	(67,577)	19.01	15.26
Forfeited	---	(2,000)	---	37.83

Outstanding at End of Period	405,670	488,173	$ 24.50	$ 23.10

The intrinsic value of options exercised in the first quarter of 2006 was $1.1 million. No shares vested during the first quarter of 2006. Total cash received from the option shares exercised in the first quarter 2006 was $0.6 million, with a tax benefit of zero, as all options were qualified stock options.

	Outstanding Options at March 31, 2006			
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life		Weighted Average Exercise Price
$3.75	34,000	2.7 years	$	3.75
$8.75	21,500	0.7 years	$	8.75
$16.69 - $19.04	115,200	6.1 years	$	18.33
$21.50 - $26.28	91,330	7.7 years	$	22.99
$34.75 - $37.83	143,640	8.8 years	$	37.68

The aggregate intrinsic value of shares outstanding at March 31, 2006 was $12.5 million with a weighted average remaining contractual term of 6.8 years.

	Exercisable Options At March 31, 2006		
Exercise Prices	Number of Shares		Weighted Average Exercise Price
$3.75	34,000	$	3.75
$8.75	21,500	$	8.75
$16.69 - $19.04	76,400	$	17.97
$21.50 - $26.28	32,420	$	22.86
$34.75 - $37.83	22,240	$	37.72

Options for 186,560 and 159,393 shares were exercisable with weighted average exercise prices of $17.52 and $14.12 at March 31, 2006 and 2005, respectively. The aggregate intrinsic value of shares exercisable at March 31, 2006 was $7.1 million with a weighted average remaining contractual term of 5.3 years.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Old Plan") and in February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). Under the Directors' Plan, which replaced the Old Plan, an aggregate of 300,000 shares of Unit's common stock may be issued upon exercise of the stock options. Under the Old Plan, on the first business day following each annual meeting of stockholders of Unit, each person who was then a member of the Board of Directors of Unit and who was not then an employee of Unit or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. Under the Directors' Plan, commencing with the year 2000 annual meeting, the amount granted has been increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. No stock options may be exercised during the first six months of its term except in case of death and no stock options are exercisable after 10 years from the date of grant.

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Activity pertaining to the Directors' Plan is as follows:

	Number of Shares Three Months Ended March 31,		Weighted Average Exercise Price	
	2006	2005	2006	2005
Outstanding at Beginning of Period	96,000	94,000	$ 24.93	$ 20.27
Granted	---	---	---	---
Exercised	(3,500)	(6,000)	20.10	13.10
Forfeited	---	---	---	---
Outstanding at End of Period	92,500	88,000	$ 25.11	$ 20.76

The intrinsic value of options exercised in the first quarter of 2006 was $0.1 million. No shares vested during the first quarter of 2006. Total cash received from option shares exercised in the first quarter 2006 was $0.1 million.

	Outstanding and Exercisable Options at March 31, 2006		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$6.90	5,000	3.1 years	$ 6.90
$12.19 - $17.54	14,000	4.8 years	$ 16.20
$20.10 - $20.46	31,500	6.7 years	$ 20.30
$28.23 - $39.50	42,000	8.6 years	$ 33.87

The aggregate intrinsic value of shares outstanding and exercisable at March 31, 2006 was $2.8 million with a weighted average remaining contractual term of 7.1 years. Options for 92,500 and 88,000 shares were exercisable with weighted average exercise prices of $25.11 and $20.76 at March 31, 2006 and 2005, respectively.

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, 2006:			
Basic earnings per common share	$ 74,913	46,200	$ 1.62
Effect of dilutive stock options and grants	--	214	(0.01)
Diluted earnings per common share	$ 74,913	46,414	$ 1.61
For the Three Months Ended March 31, 2005:			
Basic earnings per common share	$ 30,730	45,800	$ 0.67
Effect of dilutive stock options	--	250	--
Diluted earnings per common share	$ 30,730	46,050	$ 0.67

All stock options outstanding as of March 31, 2006 and 2005 were included in the computation of diluted earnings per share for the three months ending March 31, 2006 and 2005.

NOTE 3 - CREDIT AGREEMENT

As of March 31, 2006 and December 31, 2005, long-term debt consisted of the following:

	March 31, 2006	December 31, 2005
	(In thousands)	
Revolving Credit Loan, with Interest at March 31, 2006 and December 31, 2005 of 5.8% and 4.9%, Respectively	$ 90,300	$ 145,000
Less Current Portion	--	--
Total Long-Term Debt	$ 90,300	$ 145,000

The company has a revolving $235 million credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and the company has elected to have the full $235.0 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. During 2005, in connection with its amendment of the credit agreement, the company incurred additional origination, agency and syndication fees of $187,500 and these fees are being amortized over the remaining life of the agreement. The average interest rate for the first quarter of 2006 was 5.4%. At March 31, 2006 and April 26, 2006, borrowings were $90.3 million and $102.1 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 the full $235.0 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 agreement 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, 2006, all of the company's $90.3 million in borrowings were subject to the LIBOR rate.

The credit agreement 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 agreement 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, 2006, the company was in compliance with the credit agreement covenants.

Other long-term liabilities consisted of the following:

	March 31,	
	2006	2005
	(In thousands)	
Separation Benefit Plan	$ 2,844	$ 2,898
Deferred Compensation Plan	2,618	2,334
Retirement Agreement	1,613	1,856
Workers' Compensation	20,122	17,526
Gas Balancing Liability	1,080	1,080
Plugging Liability	29,598	19,496
	57,875	45,190
Less Current Portion	6,094	7,635
Total Other Long-Term Liabilities	$ 51,781	$ 37,555

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning April 1, 2006 through 2010 are $6.1 million, $94.9 million, $2.3 million, $1.4 million and $1.7 million. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at March 31, 2006 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, 2006 and 2005 relating to the company's retirement obligation for plugging liability:

	Three Months Ended	
	2006	2005
	(In thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 366	$ 226
Accretion of discount	2	8
Liability settled in the period	(18)	(23)
Reclassification of liability from long-term to short-term	81	23
Revision of estimates	46	---
Plugging liability at end of period	$ 477	$ 234
Long-Term Plugging Liability:		
Liability at beginning of period	$ 21,649	$ 18,909
Accretion of discount	308	234
Liability incurred in the period	323	144

Reclassification of liability from long-term to short-term	(81)	(23)
Revision of estimates	6,922	(2)
Plugging liability at end of period	$ 29,121	$ 19,262

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NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

In December 2004, the FASB issued FAS 123R “Share-Based Payment”, which requires that compensation cost relating to share-based payments be recognized in the company’s financial statements. FAS 123(R) was implemented by the company in the first quarter of 2006. The company previously accounted for those payments under recognition and measurement principles of APB Opinion No. 25, “Accounting for Stock Issued to Employees,” and related interpretations. For a more detailed discussion of the implementation for FAS 123(R) see Note 1 - Basis of Preparation and Presentation.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 (EITF 04-13), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 will be effective in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 will cause inventory purchases and sales under buy/sell transactions, which were recorded gross as purchases and sales, to be treated as inventory exchanges. We have not entered into the type of transactions covered under EITF 04-13, so we do not expect EITF 04-13 to have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the FASB issued Financial Accounting Standards No. 154, “Accounting Changes and Error Corrections,” which establishes new standards on accounting for changes in accounting principles. Under this new rule, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. Implementation of this statement did not have a material impact on the company's results of operations, financial condition or cash flows.

In June 2005, the Emerging Issues Task Force issued EITF Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights (“EITF 04-05”). EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners’ substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights, then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Implementation of this statement did not have a material impact on the company's results of operations, financial condition or cash flows.

NOTE 6 - GOODWILL

Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company, SerDrilco Incorporated, Sauer Drilling Company and Strata Drilling, L.L.C. over the fair value of the net assets acquired. An impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the company’s drilling segment.

NOTE 7 - 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 2005, the company entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30

In March 2005, the company also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covered the period of April through December of 2005 and had a floor of $45.00 and a ceiling of $69.25.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the March 31, 2005 balance sheet as a derivative liability of $2.7 million and at a loss of $1.6 million, net of tax, in accumulated other comprehensive income.

The company did not have any oil and natural gas hedges outstanding at March 31, 2006.

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. This period coincides with the remaining length of the company’s current credit facility. 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 $0.1 million in the first quarter of 2006 and increased by $46,500 in the first quarter of 2005. The fair value of the swap was recognized on the March 31, 2006 balance sheet as current and non-current derivative assets totaling $1.1 million and a gain of $0.7 million, net of tax, in accumulated other comprehensive income.

NOTE 8 - INDUSTRY SEGMENT INFORMATION

The company has three business segments:

. Contract Drilling,
. Oil and Natural Gas and
. Gas Gathering and Processing

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 Gas Gathering and Processing 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, 2006 and 2005 is as follows:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(In thousands)	
Revenues:		
Contract drilling	$ 167,682	$ 99,320
Elimination of inter-segment revenue	6,252	2,639
Contract drilling net of inter-segment revenue	161,430	96,681
Oil and natural gas	94,326	56,864
Gas gathering and processing	29,238	20,088
Elimination of inter-segment revenue	3,756	1,858
Gas gathering and processing net of inter-segment revenue	25,482	18,230
Other (1)	1,570	(195)
Total revenues	$ 282,808	$ 171,580
Operating Income (2):		
Contract drilling	$ 69,280	$ 23,640
Oil and natural gas	51,838	30,019
Gas gathering and processing	1,531	758
Total operating income	122,649	54,417
General and administrative expense	(3,966)	(3,971)
Interest expense	(990)	(687)
Other income (loss) - net	1,570	(195)
Income before income taxes	$ 119,263	$ 49,564

(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.

NOTE 9 - SUBSEQUENT EVENT

On April 19, 2006, the company’s wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire 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 consist of approximately 14.2 Bcfe. This acquisition will have an effective date of April 1, 2006 and the closing, which is subject to certain conditions contained in the definitive agreements, is anticipated to be May 12, 2006.

As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at the company's annual meeting on May 3, 2006, no further grants will be made under the company's Stock Option Plan or under the Employee Stock Bonus Plan. See Note 1, for a discussion of these two plans.

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, 2006, and the related consolidated condensed statements of income and comprehensive income for each of the three month periods ended March 31, 2006 and 2005 and the consolidated condensed statements of cash flows for the three month periods ended March 31, 2006 and 2005. 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, 2005, 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, 2005 and the effectiveness of the company's internal control over financial reporting as of December 31, 2005; and in our report dated March 13, 2006, 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, 2005, 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 5, 2006

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

FINANCIAL CONDITION

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 three principal business segments are:

- • contract drilling carried out by our subsidiaries Unit Drilling Company, Unit Texas Drilling, L.L.C. and Service Drilling Southwest, L.L.C.;
- • oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company; and
- • natural gas buying, selling, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C.

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.

The following is a summary of certain financial information as of March 31, 2006 and 2005 and for the three months ended March 31, 2006 and 2005:

	March 31, 2006	March 31, 2005	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 44,242	$ 31,981	38 %
Long-Term Debt	$ 90,300	$ 78,000	16 %
Shareholders' Equity	$ 913,411	$ 639,968	43 %
Ratio of Long-Term Debt to Total Capitalization	9 %	111 %	(18)%
Net Income	$ 74,913	$ 30,730	144 %
Net Cash Provided by Operating Activities	$ 140,849	$ 55,894	152 %
Net Cash Used in Investing Activities	$ (81,159)	$ (45,000)	80 %
Net Cash Used In Financing Activities	$ (59,816)	$ (11,089)	439 %

The following table summarizes certain operating information for the three months ended March 31, 2006 and 2005:

	March 31, 2006	March 31, 2005	Percent Change

Oil Production (MBbls)		327		280	17%
Natural Gas Production (MMcf)		10,713		7,653	40%
Average Oil Price Received	$	54.53	$	44.56	22%
Average Oil Price Received Excluding Hedges	$	54.53	$	44.56	22%
Average Natural Gas Price Received	$	7.04	$	5.69	24%
Average Natural Gas Price Received Excluding Hedges	$	7.04	$	5.69	24%
Average Number of Our Drilling Rigs in Use During the Period		108.6		99.3	9%
Total Number of Drilling Rigs Available at the End of the Period		111		102	9%
Average Dayrate	$	17,122	$	10,253	67%
Gas Gathered—MMBtu/day		215,341		107,254	101%
Gas Processed—MMBtu/day		23,616		30,336	(22)%
Number of Active Natural Gas Gathering Systems		36		32	13%

At March 31, 2006, we had unrestricted cash totaling $0.8 million and we had borrowed $90.3 million of the $235.0 million we have available under our credit agreement.

On April 19, 2006, our wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. The closing date for this acquisition, which is subject to certain conditions contained in the definitive agreements, is anticipated to be May 12, 2006.

Our Bank Credit Agreement. At March 31, 2006, we had a $235 million revolving credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and we have elected to have the full $235.0 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. During 2005, we incurred additional origination, agency and syndication fees of $187,500 while amending the credit agreement and these fees are being amortized over the remaining life of the agreement. The average interest rate for the first quarter of 2006 was 5.4%. At March 31, 2006 and April 26, 2006, our borrowings were $90.3 million and $102.1 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 re-determination supported the full $235.0 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 agreement 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, 2006, all of the $90.3 million we had borrowed was subject to the LIBOR rate.

The credit agreement 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 agreement 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, 2006, we were in compliance with these covenants.

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. This period coincides with the remaining length of our current credit agreement. 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 $0.1 million in the first quarter of 2006. The fair value of the swap was recognized on the March 31, 2006 balance sheet as current and non-current derivative assets totaling $1.1 million and a gain of $0.7 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At March 31, 2006 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)	$ 98,227	$ 4,318	$ 93,909	$ ---	$ ---
Retirement Agreements (2)	1,788	506	1,207	75	---
Operating Leases (3)	3,157	1,099	1,472	586	---
Drill Pipe, Drilling Rigs and Equipment Purchases (4)	35,613	35,613	---	---	---
Casing and Tubing (5)	16,263	16,263	---	---	---
SerDrilco Inc. Earn-Out Agreement (6)	7,644	7,644	---	---	---
Total Contractual Obligations	$ 162,692	$ 65,443	$ 96,588	$ 661	$ ---

(1) See the previous discussion in Management Discussion and Analysis regarding bank debt. This obligation is presented in accordance with the terms of the credit agreement and includes interest calculated at the March 31, 2006 interest rate of 5.8% 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 additional 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, will be paid in monthly payments of $25,000 starting in July 2003 and continuing through June 2009. In the first quarter of 2004, we acquired 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 additional 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, Midland, and Weatherford, Texas; Pinedale, Wyoming and Denver, Colorado under the terms of operating leases expiring through January 31, 2010. 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 $19.9 million of drill pipe and drill collars. We have committed to purchase $5.1 million of

additional rig components for the construction of new rigs. We have also committed $15.2 million for the purchase of two drilling rigs with $4.6 million paid before March 31, 2006 and the remainder due at delivery. The first of these new drilling rigs should be delivered in May 2006 and the second drilling rig is expected to be delivered in June 2006.

(5) We have made commitments to purchase $16.3 million of tubing and casing during 2006.

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, 2005, the second year of the earn-out period, the drilling rigs included in the earn-out provision had cash flow providing an earn-out of approximately $7.6 million which was paid in April 2006.

In April 2006, we committed to purchase two drilling rigs for delivery in September and October of 2006 for $6.2 million. We paid $1.2 million or 20% at the time of the commitment and have agreed to pay an additional 30% at the anticipated inspection date in mid-June with the remainder payable at delivery.

At March 31, 2006, 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 Agreement (1)	$ 2,618	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement (2)	$ 2,844	$ 386	Unknown	Unknown	Unknown
Plugging Liability (3)	$ 29,598	$ 477	$ 1,985	$ 1,787	$ 25,349
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 20,122	$ 4,725	$ 3,715	$ 1,317	$ 10,365

(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. In January 2006, the compensation committee elected to allow 33 employees to participate in the plan.

(3) On January 1, 2003 we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled or acquired).

(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 2006, 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 $4,000, $14,000 and $106,000 in 2005, 2004 and 2003, respectively.

(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 2005, we entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30

In March 2005, we also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covered the period of April through December of 2005 and had a floor of $45.00 and a ceiling of $69.25.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the March 31, 2005 balance sheet as a derivative liability of $2.7 million and at a loss of $1.6 million, net of tax, in accumulated other comprehensive income.

We did not have any oil and natural gas hedges outstanding at March 31, 2006.

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. This period coincides with the remaining term of our current credit facility. 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 $0.1 million in the first quarter of 2006 and increased by $46,500 in the first quarter of 2005. The fair value of the swap was recognized on the March 31, 2006 balance sheet as current and non-current derivative assets totaling $1.1 million and a gain of $0.7 million, net of tax, in accumulated other comprehensive income.

Self-Insurance or Retentions. 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. Following the acquisition of SerDrilco and the creation of Unit Texas Drilling, L.L.C. we have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for the rigs they operate in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas**.** Natural gas comprises 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 2006 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $340,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. Our first quarter 2006 average natural gas price was $7.04 compared to an average natural gas price of $5.69 for the first quarter of 2005. A $1.00 per barrel change in our oil price would have a $103,000 per month ($1.2 million annualized) change in our pre-tax operating cash flow based on our production in the first quarter of 2006. Our first quarter 2006 average oil price was $54.53 compared with an average oil price of $44.56 received in the first quarter of 2005.

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 agreement 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. Presently we believe that our buyers will be able to perform their commitments to us.

Oil and Natural Gas Acquisitions and Capital Expenditures. 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 41 wells (10.84 net wells) in the first quarter of 2006 compared to 26 wells (8.84 net wells) in the first quarter of 2005. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first quarter of 2006 totaled $49.8 million. Based on current prices, we plan to drill an estimated 235 wells in 2006 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be approximately $240.0 million excluding the $32.4 million to be paid in the acquisition of certain oil and natural gas properties from a group of private entities in the second quarter of 2006.

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 June 15, 2005, we completed the acquisition of certain oil and natural gas properties from a private company for an adjusted purchase price of $23.1 million in cash. The acquisition consisted of approximately 14.0 Bcfe of proved oil and natural gas reserves and several probable locations. The properties are located in Oklahoma and produced 2.5 MMcfe per day at the time of acquisition. The effective date of this acquisition was April 1, 2005. The results of operations for these acquired properties are included in the statement of income beginning June 1, 2005 with the results for the period from April 1, 2005 through May 31, 2005 included as part of the adjusted purchase price.

On November 16, 2005, we completed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $82.0 million in cash. The acquisition consisted of approximately 42.5 Bcfe of proved oil and natural gas reserves. The properties are located in Oklahoma, Arkansas and Texas and at the time of the acquisition produced 6.5 MMcfe per day. The effective date of this acquisition was July 1, 2005. The results of operations for the acquired properties are included in the statement of income beginning November 1, 2005, with the results for the period from July 1, 2005 through October 31, 2005 included as part of the adjusted purchase price.

On April 19, 2006, the company's wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire 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 consist of approximately 14.2 Bcfe. The properties currently produce 3.0 MMcfe per day. Approximately 45% of the reserves associated with these properties are located in Oklahoma, 36% are located in Texas and 19% in New Mexico. This acquisition will have an effective date of April 1, 2006 and the closing date for this acquisition, which is subject to certain conditions contained in the definitive agreements, is anticipated to be May 12, 2006.

At March 31, 2006, we had committed to purchase $16.3 million of casing and tubing to complete wells in our 2006 developmental drilling program.

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.

Because of the current high demand for drilling rigs we are experiencing some difficulty in hiring and retaining all of the rig crews we need. In response to our labor difficulties, we implemented longevity pay incentives in 2004 and increased wages in some of our drilling areas that had not already received pay increases in 2004, at the end of the second quarter of 2005. We also increased wages in one of our divisions starting in the second quarter of 2006. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs continues, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 98% utilization rate we achieved in the first quarter of 2006.

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, 2006 we have commitments to purchase approximately $19.9 million of drill pipe and drill collars in 2006. We have committed to purchase $5.1 million of additional rig components for the construction of new drilling rigs. We have also committed $15.2 million for the purchase of two new drilling rigs with $4.6 million paid prior to March 31, 2006 and the remainder due at delivery. The first of these drilling rigs should be operational by May 2006, and the second drilling rig is expected to be placed into operation in June 2006. We are also constructing another drilling rig which should be place in service in July 2006.

In April 2006, we committed to purchase two drilling rigs for delivery in September and October of 2006 for a total of $6.2 million. We paid $1.2 million or 20% at the time of the commitment and have agreed to pay an additional 30% at the anticipated inspection date in mid-June with the remainder payable at delivery.

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 2006, our average dayrate for the 111 drilling rigs that we owned was $17,541 with a 98%

utilization rate. In the first quarter of 2006 our average dayrate was $17,122 per day compared to $10,253 in the first quarter of 2005. The average number of drilling rigs used was 108.6 (98%) in the first quarter of 2006 compared to 99.3 (98%) in the first quarter of 2005. Based on the average utilization of our drilling rigs during the first quarter of 2006, a $100 per day change in dayrates has a $10,860 per day ($4.0 million annualized) change in our pre-tax operating cash flow. 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.

In January 2006, one of our drilling rigs was destroyed by a fire. Drilling rig No. 31, a 600 horsepower drilling rig, one of our smaller drilling rigs, experienced a blow out during initial drilling operations at an approximate depth of 800 feet. 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. The proceeds however will not cover the replacement cost of a new rig to replace the one destroyed. After the loss of this rig, we had 111 rigs at March 31, 2006.

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 2006 and 2005, we drilled 13 and 11 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $3.2 million and $0.9 million during the first quarter of 2006 and 2005, 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. On January 5, 2005, we acquired a subsidiary of Strata Drilling, L.L.C. for $10.5 million in cash. In this acquisition, we acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two drilling rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. After refurbishments costing $1.0 million and $5.2 million, respectively, the first drilling rig was placed in service in January 2005 and the second drilling rig was placed in service in August of 2005. Both of these rigs are in our Rocky Mountain Division. The results of operations for this acquired company are included in the statement of income for the period after January 5, 2005.

On August 31, 2005, we completed our acquisition of all the Texas drilling operations of Texas Wyoming Drilling, Inc., a Texas-based privately-owned company, with the exception of one rig which the company subsequently obtained on October 13, 2005. The purchase price for this acquisition was $31.6 million. Of that amount, $13.3 million was paid in cash and $12 million issued in stock, representing 246,053 shares, on August 31, 2005. The remaining $6.3 million was paid in cash on October 13, 2005. Six of the seven rigs are active in the Barnett Shale area of North Texas. Six of the seven drilling rigs are mechanical, with one being a diesel electric rig. They range from 400 to 1,700 horsepower. The results of operations for the first six drilling rigs are included in the statement of income for the period after August 31, 2005 and the results of operations for the seventh rig acquired is included in the statement of income for the period after October 12, 2005.

In January 2005, we completed the construction of a 1,500 horsepower diesel electric drilling rig which began operating in the Anadarko Basin. The drilling rig was constructed for approximately $2.5 million with the majority of the expenditures occurring in 2004. In May 2005, we completed the construction of a 1,500 horsepower diesel electric drilling rig which began operating in the Rocky Mountain Division. This drilling rig was constructed for $8.0 million with $1.8 million of the parts acquired in the Strata acquisition. In December 2005, we completed the construction of a 1,000 horsepower diesel electric drilling rig which began operating in the Anadarko Basin. The drilling rig was constructed for approximately $3.2 million.

In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig has been modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. The addition of this rig brings our rig fleet to 112 as of the end of April 2006. In May we began moving a rig to our Rocky Mountain Division which we completed construction on during the first quarter of 2006. We have also committed $15.2 million for the purchase of two new drilling rigs with $4.6 million paid prior to March 31, 2006 and the remainder due at delivery. The first of these drilling rigs should be delivered in May 2006, and the second drilling rig is expected to be delivered in June 2006. We are also starting to construct another drilling rig which should be placed in service in July 2006.

In April 2006, we committed to purchase two drilling rigs for delivery in September and October of 2006 for $6.2 million. We paid $1.2 million or 20% at the time of the commitment and have agreed to pay an additional 30% at the anticipated inspection date in mid-June with the remainder payable at delivery.

For our contract drilling operations, during the first quarter of 2006, we incurred $36.5 million in capital expenditures. For the year 2006, we have budgeted capital expenditures of approximately $185.0 million which includes plans to add at least 10 drilling rigs during 2006, including the five rigs previously discussed.

Natural Gas Gathering and Processing Company. Our natural gas gathering and processing operations are conducted through Superior Pipeline Company, L.L.C. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and it operates two natural gas treatment plants, owns five processing plants, 36 active gathering systems and 500 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 our natural gas and third party natural gas and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During the first quarter of 2006, Superior purchased $2.5 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 segments and our oil and natural gas operations has been eliminated in our consolidated condensed financial statements.

During the first quarter of 2006 we incurred $4.1 million in capital expenditures for our natural gas gathering and processing segment as compared to $2.6 million in the first quarter of 2005. For all of 2006, we have budgeted capital expenditures of approximately $10.0 million. Our focus is on growing this segment through the construction of new facilities or acquisitions. Superior gathered 215,341 MMBtu per day in the first quarter of 2006 compared to 107,254 MMBtu per day in the first quarter of 2005 and processed 23,616 MMBtu per day in the first quarter of 2006 compared to 30,336 MMBtu per day in the first quarter of 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 124,591 MMBtu and 36,932 MMBtu per day during the first quarter of 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed causing a reduction in processed natural gas between the quarters.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 11 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 2005, the total paid to us for all of these fees was $1.0 million and we expect the amount to approximately be the same in 2006. 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

Before January 1, 2006, we accounted for our 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.

In the first quarter of 2006, we adopted Financial Accounting Standards (FAS) No. 123(R) “Share-Based Payment”, which revises FAS 123, "Accounting for Stock-Based Compensation." Under FAS 123(R), we are required to select a valuation technique or option-pricing model that meets the criteria as stated in the standard, which includes a binomial model and the Black-Scholes model. We have elected to use the Black-Scholes model. At the adoption of FAS 123(R) we elected to use the "modified prospective method" as defined in the standard. This method requires the company to value stock options prior to its adoption of FAS123(R) under the grant-date fair value estimated in accordance with FAS 123, and expense these amounts over the stock options remaining vesting period. This resulted in the company expensing $0.2 million in the contract drilling segment, $0.2 million in the oil and natural gas exploration segment and $0.2 million to corporate general and administrative expense, for a total of $0.6 million, in the first quarter of 2006 and capitalized as part of geological and geophysical cost $0.2 million. On March 29, 2005, the SEC published Staff Accounting Bulletin (SAB) 107, which provides the staff's views on a variety of matters relating to stock-based payments. SAB 107 requires stock-based compensation be classified in the same line items as cash compensation. Results for prior periods have not been restated and we did not have a cumulative adjustment from the implementation of FAS 123(R). When the company adopted FAS 123(R), on January 1, 2006, deferred compensation of $2.2 million was reduced to zero with a corresponding decrease to additional paid in capital. The remaining unrecognized compensation cost related to unvested awards at March 31, 2006 is approximately $3.9 million with $1.0 million of that amount to be capitalized. The weighted average period of time over which this cost will be recognized is one year. If we had applied the fair value provisions of FAS 123(R) to stock-based employee compensation for the three months ended March 31, 2005, net income and earnings per share would have been reduced by approximately $0.5 million and $0.1, respectively.

Under the provision of FAS 123(R), tax deductions associated with our stock based compensation plans in excess of the compensation cost recognized are recorded as an increase to additional paid in capital and reflected as a financing cash flow in the statement of cash flows. In the current quarter, all options exercised were incentive stock options for which no tax deduction was immediately available. Accordingly, the adoption of FAS 123(R) did not impact our consolidated statements of cash flows for the period ended March 31, 2006.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 (EITF 04-13), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 will be effective in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 will cause inventory purchases and sales under buy/sell transactions, which were recorded gross as purchases and sales, to be treated as inventory exchanges. We have not entered into the type of transactions covered under EITF 04-13, so we do not expect EITF 04-13 to have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the FASB issued Financial Accounting Standards No. 154, “Accounting Changes and Error Corrections,” which establishes new standards on accounting for changes in accounting principles. Under this new rule, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. Implementation of this statement did not have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the Emerging Issues Task Force issued EITF Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights (“EITF 04-05”). EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners’ substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights, then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Implementation of this statement did not have a material impact on our results of operations, financial condition or cash flows.

RESULTS OF OPERATIONS

Quarter Ended March 31, 2006 versus Quarter Ended March 31, 2005

Provided below is a comparison of selected operating and financial data for the first quarter of 2006 versus the third quarter of 2005:

		Quarter Ended March 31, 2006		Quarter Ended March 31, 2005	Percent Change
Total Revenue	$	282,808,000	$	171,580,000	65%
Net Income	$	74,913,000	$	30,730,000	144%
Drilling:					
Revenue	$	161,430,000	$	96,681,000	67%
Operating costs	$	80,309,000	$	63,431,000	27%
Percentage of revenue from daywork contracts		100%		100%	---
Average number of rigs in use		108.6		99.3	9%
Average dayrate on daywork contracts	$	17,122	$	10,253	67%
Depreciation	$	11,841,000	$	9,610,000	23%
Oil and Natural Gas:					
Revenue	$	94,326,000	$	56,864,000	66%
Operating costs	$	18,306,000	$	12,413,000	47%
Average natural gas price (Mcf)	$	7.04	$	5.69	24%
Average oil price (Bbl)	$	54.53	$	44.56	22%
Natural gas production (Mcf)		10,713,000		7,653,000	40%
Oil production (Bbl)		327,000		280,000	17%
Depreciation, depletion and amortization rate (Mcfe)	$	1.90	$	1.54	23%
Depreciation, depletion and amortization	$	24,182,000	$	14,432,000	68%
Gas Gathering and Processing:					
Revenue	$	25,482,000	$	18,230,000	40%
Operating costs	$	22,801,000	$	16,834,000	35%
Depreciation	$	1,150,000	$	638,000	80%
Gas gathered - MMbtu/day		215,341		107,254	101%
Gas processed - MMbtu/day		23,616		30,336	(22)%
General and Administrative Expense	$	3,966,000	$	3,971,000	---%
Interest Expense	$	990,000	$	687,000	44%
Income Tax Expense	$	44,350	$	18,834	135%
Average Interest Rate		5.41%		3.74%	45%
Average Long-Term Debt Outstanding	$	113,599,000	$	94,056,000	21%

Industry demand for our drilling rigs increased throughout 2005 and remained strong in the first quarter of 2006. Drilling revenues increased $64.7 million or 67% in the first quarter of 2006 versus the first quarter of 2005. During the first quarter of 2005 we added two drilling rigs and throughout the remainder of 2005, we added 10 additional drilling rigs five through construction and seven through acquisition. We lost one of our older rigs to a blow out and subsequent fire early in the first quarter of 2006. The 12 additional drilling rigs increased our first quarter 2006 drilling revenues by approximately 17%. The increase in revenue from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 14% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 86% of the increase in total drilling revenues. Our average dayrate in the first quarter of 2006 was 67% higher than in the first quarter of 2005. Demand for our drilling rigs is anticipated to be strong throughout 2006, but we do not expect the dramatic increases in daywork revenue per day as was experienced throughout 2005 and into the first quarter of 2006. Opportunities to increase rig revenues through economical acquisition of existing drilling rigs is expected to be limited in 2006, due to the high demand for drilling rigs and the resulting sales prices being at very high levels.

Drilling operating costs increased $16.9 million or 27% between the comparative quarters. The increase in operating costs from the 12 drilling rigs placed in service in 2005 and increased utilization of our previously owned drilling rigs represented 35% of the total increase in operating cost. Increases in operating cost per day accounted for 65% of the increase in total operating costs. Operating cost per day increased $1,117 in the first quarter of 2006 when compared with the first quarter of 2005. A majority of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost and cost associated with rig moves the primary reason for the increase. We expect the demand for drilling rigs to remain high throughout 2006 and into 2007, resulting in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in first quarter of 2006 or 2005. Contract drilling depreciation increased $2.2 million or 23%. The addition of the 12 drilling rigs placed in service in 2005 increased depreciation $1.1 million or 11% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Oil and natural gas revenues increased $37.5 million or 66% in the first quarter of 2006 as compared to the first quarter of 2005. Increased oil and natural gas prices accounted for 48% of the increase while increased equivalent natural gas production volumes accounted for 52% of the increase. In the first quarter of 2006, natural gas production increased by 40% while oil production increased 17%. Increased natural gas production came primarily from our ongoing development drilling activity and two acquisitions completed in 2005, subsequent to the end of the first quarter of 2005. We are forecasting an 18% to 20% increase in total production for 2006 compared to 2005. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $5.9 million or 47% in the first quarter of 2006 as compared to 2005. An increase in the average cost per equivalent Mcf produced represented 30% of the increase in production costs with the remaining 70% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 53% of the increase, gross production taxes 32% and general and administrative cost directly related to oil and natural gas production 15%. Lease operating expenses per Mcfe increased 8% between the comparative quarters. The increase is primarily due to increases in the cost of goods and services which was partially offset by a 4% reduction in workover cost between the comparative quarters. Gross production taxes increased due to the increase in natural gas volumes produced and the increase in commodity prices between the comparative quarters. General and administrative expenses increased as labor costs increased primarily due to a 19% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $9.8 million or 68%. Higher production volumes accounted for 53% of the increase while increases in our DD&A rate represented 47% of the increase. The increase in our DD&A rate in the first quarter of 2006 compared to the first quarter of 2005 resulted primarily from a 14% increase in our finding cost in 2005 and continued increases in our finding cost into the first quarter of 2006. Demand for drilling rigs throughout our areas of exploration have increased the dayrates we pay to drill wells in our developmental program and the increase in natural gas and oil prices has caused increased sales prices for producing property acquisitions. We do believe there continues to be economical opportunities for acquisitions.

Our natural gas gathering and processing segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate two natural gas treatment plants and own five processing plants, 36 active gathering systems and 500 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 natural gas gathering and processing revenues, operating expenses and depreciation were $7.3 million, $6.0 million and $0.5 million higher in the first quarter of 2006 versus 2005, respectively. Gas gathering volumes per day were 101% higher in the first quarter of 2006 as compared to the first quarter of 2005 while gas processing volumes per day were down 22% in the first quarter of 2006 as compared to the first quarter of 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 124,591 MMBtu and 36,932 MMBtu per day during the first quarter of 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed causing a reduction in processed natural gas between the quarters. Our focus is on growing this segment through the construction of new facilities or acquisitions. Continued growth in this segment enhances our ability to gather and market our natural gas and third party natural gas and gives us addition capacity to construct or acquire existing natural gas gathering and processing facilities.

In the first quarter of 2005, we recognized $0.7 million in personnel cost from the recognition of a liability associated with the retirement of Mr. Nikkel from his position as Chief Executive Officer. This 2005 expense offset increases experienced in general and administrative expenses in 2006 primarily from increases in employee cost between the comparative quarters.

Total interest expense increased 44% between the comparative quarters. Average debt outstanding was higher in the first quarter of 2006 as compared to the first quarter of 2005 primarily due to the fourth quarter 2005 acquisition of producing properties for $82.0 million in cash. Average debt outstanding accounted for approximately 26% of the interest expense increase, with the remaining 73% resulting from an increase in average interest rates on our bank debt. A reduction in interest expense of $0.1 million from the settlement of the interest rate swap partially offset the 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 $0.7 million of interest in the first quarter of 2006 compared with $0.3 million in the first quarter of 2005.

Income tax expense increased $25.5 million or 135% due primarily to the increase in income before income taxes. Our effective tax rate for the first quarter of 2006 was 37.1% versus 38.0% in the first quarter of 2005. With our increase in income and the reduction of a majority of our net operating loss carryforwards in prior periods, the portion of our taxes reflected as current income tax expense has increased in the first quarter of 2006 when compared with the first quarter of 2005. Current income tax expense for the first quarter of 2006 and 2005 was $30.2 million and $9.4 million, respectively. Income taxes paid in the first quarter of 2006 were $14.5 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.

Item 3. Quantitative and Qualitative Disclosures 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 quarter 2006 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $340,000 per month ($4.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $103,000 per month ($1.2 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. We did not have any oil or natural gas hedges outstanding at March 31, 2006.

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 quarter of 2006, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $0.6 million.

Item 4. 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, 2006 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.

There were no changes in the company's internal controls over financial reporting during the quarter ended March 31, 2006 that could significantly affect these internal controls.

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.

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

- the amount and nature of our future capital expenditures;
- wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- business strategy;
- production of oil and natural gas reserves;
- growth potential for our gathering and processing operations;
- gathering systems and processing plants to be constructed or acquired;
- 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. 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 Securities and Exchange Commission. We encourage you to get and read that document.

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, 2005, 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.

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 5, 2006

By:/s/ Larry D. Pinkston
LARRY D. PINKSTON
Chief Executive Officer and Director

Date: May 5, 2006

By:/s/ David T. Merrill
DAVID T. MERRILL
Chief Financial Officer and
Treasurer