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, 2004
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]

U N I T C O R P O R A T I O N
(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation or organization)	**(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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes _X_ No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock, $.20 par value	**45,715,768**
Class	**Outstanding at May 3, 2004**

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)

	December 31, 2003	March 31, 2004
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 598	$ 377
Restricted cash	--	5,352
Accounts receivable	58,807	66,567
Materials and supplies	8,023	10,409
Income tax receivable	112	--
Other	5,202	5,763
Total current assets	72,742	88,468
Property and Equipment:		
Drilling equipment	424,321	432,419
Oil and natural gas properties, on the full cost method:		
Proved properties	528,110	655,391
Undeveloped leasehold not being amortized	17,486	25,244
Transportation equipment	9,828	10,108
Other	14,535	15,611
	994,280	1,138,773
Less accumulated depreciation, depletion, amortization and impairment	385,219	403,263
Net property and equipment	609,061	735,510
Goodwill	23,722	23,722
Other Assets	7,400	9,114
Total Assets	$ 712,925	$ 856,814

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

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

	December 31, 2003	March 31, 2004
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term liabilities and debt	$ 1,015	$ 984
Accounts payable	32,871	30,820
Accrued liabilities	17,925	30,996
Total current liabilities	51,811	62,800
Long-Term Debt	400	75,000
Other Long-Term Liabilities	17,893	23,700
Deferred Income Taxes	127,053	162,641
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, 45,592,012 and 45,709,568 shares issued, respectively	9,117	9,141
Capital in excess of par value	307,938	309,538
Accumulated other comprehensive income	--	(226)
Retained earnings	198,713	214,220
Total shareholders' equity	515,768	532,673
Total Liabilities and Shareholders' Equity	$ 712,925	$ 856,814

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF INCOME (UNAUDITED)(NOTE 1)

	Three Months Ended March 31,	
	2003	2004
	(In thousands except per share amounts)	
Revenues:		
Contract drilling	$ 34,566	$ 63,214
Oil and natural gas	33,248	37,990
Other	750	696
Total revenues	68,564	101,900
Expenses:		
Contract drilling:		
Operating costs	27,811	46,556
Depreciation	4,894	7,464
Oil and natural gas:		
Operating costs	6,615	9,732
Depreciation depletion and amortization	6,047	10,177
General and administrative	2,450	2,771
Other	325	222
Interest	211	417
Total expenses	48,353	77,339
Income Before Income Taxes	20,211	24,561
Income Tax Expense:		
Current	155	571
Deferred	7,525	8,763
Total income taxes	7,680	9,334
Equity in Earnings of Unconsolidated Investments, Net of Income Tax	128	280
Income Before Change in Accounting Principle	12,659	15,507
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811)	1,325	--
Net Income	$ 13,984	$ 15,507
Basic Earnings per Common Share:		
Income before change in accounting principle	$ 0.29	$ 0.34
Cumulative effect of change in accounting principle, net of income tax	0.03	--
Net income	$ 0.32	$ 0.34
Diluted Earnings per Common Share:		
Income before change in accounting principle	$ 0.29	$ 0.34
Cumulative effect of change in accounting principle, net of income tax	0.03	--
Net income	$ 0.32	$ 0.34

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,	
	2003	2004
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 13,984	$ 15,507
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion, and amortization	11,103	17,886
Deferred tax expense	7,604	8,935
Other	(1,028)	(17)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(8,979)	899
Accounts payable	(434)	(2,388)
Material and supplies inventory	1,017	(2,386)
Prepaid expenses	112	(565)
Contract advances	27	2,955
Other - net	1,029	1,786
Net cash provided by operating activities	24,435	42,612
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including producing property acquisitions)	(18,663)	(124,324)
Proceeds from disposition of assets	141	1,023
Other-net	31	350
Net cash used in investing activities	(18,491)	(122,951)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(4,500)	74,600
Net payments of notes payable and other long-term debt	(1,000)	--
Proceeds from exercise of stock options	393	219
Book overdrafts	(1,106)	5,299
Net cash from (used in) financing activities	(6,213)	80,118
Net Decrease in Cash and Cash Equivalents	(269)	(221)
Cash and Cash Equivalents, Beginning of Year	497	598
Cash and Cash Equivalents, End of Period	$ 228	$ 377

See Note 3 for non-cash investing activities.

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,	
	2003	2004
	(In thousands)	
Net Income	$ 13,984	$ 15,507
Other Comprehensive Income, Net of Taxes:		
Change in value of cash flow derivative instruments used as cash flow hedges	155	(304)
Adjustment reclassification - derivative settlements	--	78
Comprehensive Income	$ 14,139	$ 15,281

The accompanying notes are an integral part of the 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 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 present fairly the interim financial information. Certain reclassifications have been made to prior year financial information to conform to the current period presentation.

Results for the three months ended March 31, 2004 are not necessarily indicative of the results to be realized during the full year. The consolidated condensed financial statements have been derived from audited financial statements and should be read with the company's Annual Report on Form 10-K for the year ended December 31, 2003. Our independent accountants have performed a review of these interim financial statements in accordance with standards established by the American Institute of Certified Public Accountants. Under Rule 436(c) under the Securities Act of 1933, their report of that review should not be considered as part of any registration statements prepared or certified by them within the meaning of Section 7 and 11 of that Act and the independent accountants' liability under Section 11 does not extend to it.

The company's stock-based compensation plans are accounted for under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense included in reported net income is the company's matching 401(k) contribution. The following table illustrates the effect on net income and earnings per share if the company had applied the fair value recognition provisions of Financial Accounting Standards Board Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	Three Months Ended 2003	**Three Months Ended 2004**
	(In thousands except per share amounts)	
Net Income, as Reported	$ 13,984	$ 15,507
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax	167	219
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(404)	(513)
Pro Forma Net Income	$ 13,747	$ 15,213
Basic Earnings per Share:		
As reported	$ 0.32	$ 0.34
Pro forma	$ 0.32	$ 0.33
Diluted Earnings per Share:		
As reported	$ 0.32	$ 0.34
Pro forma	$ 0.32	$ 0.33

The fair value of each option granted is estimated using the Black-Scholes model. There were no options granted in the first quarter of 2003 and 2004. For options granted in fiscal 2002 and 2003, the company’s estimate of stock volatility was 0.53 and 0.52, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.24% in 2002 and 2003. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees.

NOTE 2 - EARNINGS PER SHARE

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

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Three Months Ended March 31, 2003:			
Basic earnings per common share:			
Income before change in accounting principle	$ 12,659	43,432	$ 0.29
Cumulative effect of change in accounting principle net of income tax	1,325	43,432	0.03
Net Income	$ 13,984	43,432	$ 0.32
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		43,432	
Effect of dilutive stock options		205	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,637	
Income before change in accounting principle	$ 12,659	43,637	$ 0.29
Cumulative effect of change in accounting principle net of income tax	1,325	43,637	0.03
Net Income	$ 13,984	43,637	$ 0.32

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Three Months Ended March 31, 2004:			
Basic earnings per common share:			
Income before change in accounting principle	$ 15,507	45,671	$ 0.34
Net Income	$ 15,507	45,671	$ 0.34
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		45,671	
Effect of dilutive stock options		188	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		45,859	
Income before change in accounting principle	$ 15,507	45,859	$ 0.34
Net Income	$ 15,507	45,859	$ 0.34

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended March 31, 2003 because the option exercise prices were greater than the average market price of common shares:

	2003
Options	176,000
Average exercise price	$ 19.17

NOTE 3 – ACQUISITIONS

On January 30, 2004, the company acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash ($92.2 million net of cash acquired). PetroCorp Incorporated explores and develops oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in the acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast basin. The acquired properties increased the company's oil and natural gas reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for development drilling in the future. The results of operations for the acquired entity are included in the statement of income for the period subsequent to January 30, 2004.

The total consideration paid for this acquisition was allocated as follows (in thousands):

Working Capital	$ 97,051
Undeveloped Oil and Natural Gas Properties	6,321
Proved Oil and Natural Gas Properties	108,984
Property and Equipment – Other	382
Other Assets	1,445
Other Long-Term Liabilities	(5,271)
Deferred Income Taxes (net)	(26,792)
Total consideration	$ 182,120

The amount paid was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities sections of the company's consolidated condensed financial statements of cash flows.

As of the acquisition date, cash of $5.5 million, otherwise payable to the shareholders of PetroCorp Incorporated, was transferred to an escrow account to reserve for certain liabilities and related costs that may be incurred by PetroCorp Incorporated after the closing of the acquisition. As of March 31, 2004, $5.4 million remained in escrow and is reflected as restricted cash.

Unaudited summary pro forma results of operations for the company, reflecting the above acquisitions as if they had occurred at the beginning of the year ended December 31, 2003 are as follow:

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2004
	(In thousands except per share amounts)	
Revenues	$ 78,993	$ 105,080
Income Before Change in Accounting Principle	$ 15,245	$ 16,069
Net Income	$ 13,601	$ 16,069
Diluted Earnings per Share:		
Income before change in accounting principle	$ 0.35	$ 0.35
Net income	$ 0.31	$ 0.35

The pro forma results of operations are not necessarily indicative of the actual results of operations that would have occurred had the purchase actually been made at the beginning of the respective periods nor of the results which may occur in the future.

NOTE 4 - LOAN AGREEMENT

On January 30, 2004, in conjunction with the company's acquisition of PetroCorp Incorporated, the company replaced its loan agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although, the current value of the company's assets under the latest loan value determination supported the full $150 million, the company elected to set the loan commitment at $120 million in order to reduce financing costs. The company pays a commitment fee of .375 of 1% for any unused portion of the commitment amount. The company paid origination, agency and syndication fees of $515,000 at the inception of the new agreement $40,000 of which will be paid annually and the remainder of the fees will be amortized over the 4 year life of the loan.

The borrowing base under the current credit facility is subject to a semi-annual re-determination on May 10 and November 10 of each year, beginning May 10, 2004. The calculation is based primarily on the sum of a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of the company's drilling rig fleet, limited to $20 million, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lender or the company) between each scheduled re-determination date if conditions warrant such a request.

At the company's election, any part of the outstanding debt may be fixed at a Eurodollar Rate for a 30, 60, 90 or 180 day term. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid on three days prior notice to the administrative agent. Interest on the Eurodollar Rate is computed at the Eurodollar 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 Eurodollar 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.

The loan 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 the company's banks.

The loan 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 loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

The company is in compliance with the covenants of its loan agreement as of March 31, 2004.

NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2003 the company 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. The company owns oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. 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 the plugging liabilities.

The following table shows the activity for the three months ending March 31, 2003 and 2004 relating to the company's retirement obligation for plugging liability:

	Short-Term Plugging Liability	Long-Term Plugging Liability
	(In Thousands)	
Plugging Liability 1/1/04	$ 303	$ 11,691
Accretion of Discount	4	173
Liability Incurred in the Period	--	5,566
Liability Settled in the Period	(57)	--
Sold	--	(17)
Reclassification of Liability From Long- to Short-Term	--	--
Plugging Liability 3/31/04	$ 250	$ 17,413

On January 17, 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. FIN 46, as amended, was effective for the company in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, primarily Eagle Energy Partnership I, L.P., did not have an impact on the company's financial position or results of operations or cash flows. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, FIN 46 and the amendment of FIN 46 were effective for the company, as amended, in the quarter ending March 31, 2004. The company evaluated FIN 46 and FIN 46(R) with regard to these types of entities in which it has an ownership interest and there was no material impact to the financial position, results of operations or cash flows from the adoption of FIN 46 and FIN 46(R).

NOTE 6 - INTANGIBLE UNDEVELOPED LEASEHOLD AND INTANGIBLE DEVELOPED LEASEHOLD

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the the FASB in June 2001 and became effective for the company on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the notes to the company's financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, the company, like many other oil and gas companies, has included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective. The company's results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

At March 31, 2004, the company had undeveloped leaseholds of approximately $16.4 million that would be classified on our balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $129.1 million that would be classified as "intangible developed leasehold" if the interpretations were applied. This classification would require the company to make the disclosures set forth under FAS 142 related to these interests.

The Financial Accounting Standards Emerging Issues Task Force (EITF) has recently issued proposed FASB Staff Position (FSP) FAS 141-a and 142-a "Interaction of FASB Statements No. 141, *Business Combinations*, and No. 142, *Goodwill and Other Intangible Assets*, and EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets." The proposed FSP would amend FAS 141 and FAS 142 to remove some inconsistencies between the standards related to the proper classification of assets related to mineral rights.

On April 30, 2004, the FASB directed the FASB staff to issue the FSP and the guidance in the FSP shall be applied to the first reporting period beginning after April 29, 2004. Under the FSP certain use rights may have characteristics of tangible assets, so we intend to continue to classify our oil and natural gas mineral extraction rights as tangible oil and gas properties.

NOTE 7 - HEDGING ACTIVITY

Periodically the company hedges the prices it will receive for a portion of its future natural gas and oil production. The hedge is made in an attempt to reduce the impact and uncertainty that price variations have on cash flow.

During the first quarter of 2003, the company entered into two natural gas collar contracts. Each contract was for 10,000 MMBtu's of production per day and covered the period of April through September 2003. One contract had a floor price of $4.00 and a ceiling price of $5.75 and the other contract has a floor price of $4.50 and a ceiling price of $6.02. During the first quarter of 2003, the company also entered into two oil collar contracts. Each contract was for 5,000 barrels of production per month and covered the period of May through December 2003. One contract had a floor price of $25.00 and a ceiling price of $32.20 and the other contact had a floor price of $26.00 and a ceiling price of $31.40. The fair value of the collar contracts was recognized on the March 31, 2003 balance sheet as a derivative asset of $246,000 and at $155,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective and thus did not affect net income.

During the first quarter of 2004, the company entered into a natural gas collar covering 10,000 MMBtu's per day of its natural gas production. The transaction covers the periods of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. The company also entered into an oil hedge covering 1,000 barrels per day of its oil production. The transaction covers the periods of February through December of 2004 and has an average price of $31.40. The fair value of the collar contract and the hedge was recognized on the March 31, 2004 balance sheet as a derivative liability of $365,000 and at a loss of $226,000, net of tax, in accumulated other comprehensive income. Oil revenues were reduced by $127,000 for the quarter due to the settlement of the oil hedge in February and March of 2004.

NOTE 8 - INDUSTRY SEGMENT INFORMATION

The company has two business segments: Contract Drilling, and Oil and Natural Gas, representing its two strategic business units offering different products and services. The Contract Drilling segment provides land contract drilling of oil and natural gas wells and the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties.

Management evaluates the performance of its 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 industry segment for the three month periods ended March 31, 2003 and 2004 is as follows:

	Three Months Ended March 31, 2003	2004
	(In thousands)	
Revenues:		
Contract drilling	$ 36,513	$ 65,580
Elimination of inter-segment revenue	1,947	2,366
Contract drilling net of inter-segment revenue	34,566	63,214
Oil and natural gas	33,248	37,990
Other	750	696
Total revenues	$ 68,564	$ 101,900
Operating Income (1):		
Contract drilling	$ 1,861	$ 9,194
Oil and natural gas	20,586	18,081
Total operating income	22,447	27,275
General and administrative expense	(2,450)	(2,771)
Interest expense	(211)	(417)
Other income - net	425	474
Income before income taxes	$ 20,211	$ 24,561

(1) 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.

The cumulative effect of change in accounting principle recorded in the first quarter of 2003 of $1,325,000, net of $811,000 in income tax, is all related to the oil and natural gas segment.

REPORT OF INDEPENDENT ACCOUNTANTS

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, 2004, and the related consolidated condensed statements of income, comprehensive income and cash flows for the three month periods ended March 31, 2003 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical review procedures to financial data and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, 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 condensed consolidated 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 auditing standards generally accepted in the United States of America, the consolidated balance sheet as of December 31, 2003, and the related consolidated statements of income, shareholder’s equity and cash flows for the year then ended (not presented herein); and in our report dated February 18, 2004, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2003, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
April 19, 2004

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 generated from our two principal business segments (and our subsidiaries that carry out those operations) and borrowings under our bank loan agreement. Our cash flow is influenced mainly by the prices we receive for our natural gas production, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production. At March 31, 2004, we had cash totaling $377,000 and we had borrowed $75.0 million of the $120.0 million we have elected to have available under our loan agreement.

Our two principal business segments are (i) contract drilling carried out by our subsidiaries Unit Drilling Company and Service Drilling Southwest, L.L.C. and (ii) oil and natural gas exploration, carried out by our subsidiaries Unit Petroleum Company and PetroCorp Incorporated.

The following is a summary of certain financial information on March 31, 2003 and March 31, 2004 and for the three months ended March 31, 2003 and March 31, 2004:

	March 31, 2003	March 31, 2004	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 28,571	$ 25,668	(10%)
Long-Term Debt	$ 26,000	$ 75,000	188%
Shareholders' Equity	$ 436,984	$ 532,673	22%
Ratio of Long-Term debt to Total Capitalization	6%	12%	
Income Before Change in Accounting Principle	$ 12,659	$ 15,507	22%
Net Income	$ 13,984	$ 15,507	11%
Net Cash Provided by Operating Activities	$ 24,435	$ 42,612	74%
Net Cash Used in Investing Activities	$ (18,491)	$ (122,951)	565%
Net Cash Provided by (Used in) Financing Activities	$ (6,213)	$ 80,118	1,390%

The following table summarizes certain operating information for the first three months of 2003 and 2004:

	2003	2004	Percent Change
Oil Production (MBbls)	114	215	89%
Natural Gas Production (MMcf)	4,855	6,294	30%
Average Oil Price Received	$ 30.40	$ 30.63	1%
Average Natural Gas Price Received	$ 5.96	$ 4.90	(18%)
Average Number of Our Drilling Rigs in Use During the Period	50.8	81.7	61%
Total Number of Our Drilling Rigs Available at the End of the Period	75	88	17%

Our Bank Loan Agreement. On January 30, 2004, in conjunction with our acquisition of PetroCorp Incorporated, we replaced our loan agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although the current value of our assets under the latest loan value computation supported the full $150 million, we elected to set the loan commitment at $120 million in order to reduce financing costs since we are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We paid origination, agency and syndication fees of $515,000 at the inception of the new agreement, $40,000 of which will be paid annually and the remainder of the fees amortized over the four year life of the loan. Following the acquisition of PetroCorp Incorporated our borrowings were $90.0 million. Prior to March 31, 2004 we reduced our borrowings and at March 31, 2004 and April 19, 2004 our borrowings were $75.0 million.

The loan value under our current credit facility is subject to a semi-annual re-determination on May 10 and November 10 of each year, beginning May 10, 2004. The calculation is based primarily on the sum of a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, is added to the loan value. The agreement allows for one requested special re-determination of the borrowing base by either the lender or us between each scheduled re-determination date if conditions warrant such a request.

At our election, any part of the outstanding debt may be fixed at a Eurodollar Rate for a 30, 60, 90 or 180 day term. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid on three days prior notice to the administrative agent. Interest on the Eurodollar Rate is computed at the Eurodollar 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 is payable at the end of each term or every 90 days whichever is less. Borrowings not under the Eurodollar 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, 2004, all of our $75.0 million debt was subject to the Eurodollar Rate.

The loan 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 loan 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.

The company is in compliance with the covenants of its loan agreement as of March 31, 2004.

Contractual Commitments. We have the following contractual obligations at March 31, 2004:

	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)	$ 75,000	$ --	$ --	$ 75,000	$ --
Retirement Agreement(2)	1,575	300	600	600	75
Operating Leases(3)	3,386	725	1,411	892	358

Drill Pipe Acquisitions(4)	9,309	9,309	--	--	--
Total Contractual Obligations	$ 89,270	$10,334	$ 2,011	$ 76,492	$ 433

(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt.
(2) The retirement agreement represents a contractual obligation made in the second quarter of 2001 for a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability, including accrued interest, is being paid monthly in $25,000 installments continuing through June 2009. The discounted liability is on our consolidated condensed balance sheet as part of other long-term liabilities and is presented above undiscounted.
(3) We lease office space in Tulsa and Woodward, Oklahoma and Houston, Texas under the terms of operating leases expiring through January 31, 2010 along with leasing space on short-term commitments to stack excess rig equipment and production inventory. Subsequent to March 31, 2004, we signed a rental agreement for a district office in Midland, Texas. The rental agreement's term for three years and will be approximately $2,600 per month.
(4) Due to the increasing cost of steel and the potential for limited availability of new drill pipe within the industry, in the first quarter of 2004 we made a commitment to purchase approximately 275,000 feet of drill pipe from three different suppliers by the end of 2004.

At March 31, 2004, we have the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Amount Committed Or Accrued	Amount of Commitment Expiration Per Period: Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred Compensation Agreement(1)	$ 1,928	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,623	$ 434	Unknown	Unknown	Unknown
Plugging Liability(3)	$ 17,663	$ 250	$ 439	$ 736	$ 16,238
Gas Balancing Liability(4)	$ 1,191	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(5)	Unknown	Unknown	Unknown	Unknown	Unknown

(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 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 Unit 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 Unit 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.

(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 a liability recorded for certain properties where we believe there are insufficient 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 2004, 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 $106,000 in 2003 for limited partners' interests. No repurchases were made in the first quarter of 2004.

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.

During the first quarter of 2003, we entered into two natural gas collar contracts. Each contract was for 10,000 MMBtu's of production per day and covered the period of April through September 2003. One contract had a floor price of $4.00 and a ceiling price of $5.75 and the other contract has a floor price of $4.50 and a ceiling price of $6.02. During the first quarter of 2003, we also entered into two oil collar contracts. Each contract was for 5,000 barrels of production per month and covered the period of May through December 2003. One contract had a floor price of $25.00 and a ceiling price of $32.20 and the other contact had a floor price of $26.00 and a ceiling price of $31.40. The fair value of the collar contracts was recognized on the March 31, 2003 balance sheet as a derivative asset of $246,000 and at $155,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective and thus did not affect net income.

During the first and second quarters of 2004, we entered into two natural gas collars. Each contract was for 10,000 MMBtu's of production per day. One contract covers the period of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. The other contract covers the period of May through October of 2004 and has a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels per day of oil production. The transaction covers the periods of February through December of 2004 and has an average price of $31.40. The fair value of the collar contract and the hedge was recognized on the March 31, 2004 balance sheet as a derivative liability of $365,000 and at a loss of $226,000, net of tax, in accumulated other comprehensive income. Oil revenues were reduced by $127,000 for the quarter due to the settlement of the oil hedge in February and March of 2004.

Self-Insurance or Retentions. We are self-insured (or have a retention) for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. The exposure (i.e. our deductible or retention) per occurrence ranges from $200,000 for general liability to $1 million for 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 claims. There is no assurance that such coverage will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco we have continued to use its ERISA governed occupational injury benefit plan to cover its employees in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas. With the acquisition of PetroCorp Incorporated (as previously discussed in Note 3 of the Notes to Consolidated Financial Statements), natural gas comprises 86% of our total oil and natural gas reserves. Any significant change in natural gas prices has a material affect 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, the amount and timing of liquid natural gas imports 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 production in 2004 after the acquisition of PetroCorp Incorporated, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $206,800 per month ($2,482,000 annualized) change in our pre-tax operating cash flow. Our first quarter 2004 average natural gas price was $4.90 compared to an average natural gas price of $5.98 for the first quarter of 2003. A $1.00 per barrel change in our oil price would have a $76,400 per month ($917,000 annualized) change in our pre-tax operating cash flow based on our production in 2004 after the acquisition of PetroCorp Incorporated. Our first quarter 2004 average oil price was $30.63 compared with an average oil price of $30.40 received in the first quarter of 2003.

Because 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 affect the semi-annual determination of the amount available for us to borrow under our bank loan 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.

We sell most of our natural gas production to third parties under month-to-month contracts. Several of these buyers have experienced financial complications resulting from the recent investigations into the energy trading industry. The long-term implications to the energy trading business, as well as to oil and natural gas producers, because of these investigations remains, to be determined. We continue to evaluate the information available to us about our buyers and try to reduce any possible future adverse impact to us. Presently we believe that our buyers will be able to perform their commitments to us. We own a 16.7% limited partner interest in Eagle Energy Partners I LP, whose purchases, which are competitively marketed, accounted for 25% of our oil and natural gas revenues in the first quarter of 2004 and they marketed approximately 48% of the natural gas volumes we sold for ourselves and third parties during the same period.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Any 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 34 wells (15.98 net wells) in the first quarter of 2004 compared to 18 wells (9.13 net wells) in the first quarter of 2003. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first quarter of 2004 totaled $135.3 million with $115.7 million relating to the PetroCorp Incorporated acquisition. Included in the PetroCorp Incorporated acquisition was a plugging liability and deferred tax liability of $32.1 million. Based on current prices, we plan to drill an estimated 165 to 175 wells in 2004 and total capital expenditures for oil and natural gas exploration and acquisitions is planned to be around $95 million excluding the PetroCorp Incorporated acquisition. Due to the shortage of steel and the resulting increase in prices we purchased 320,000 feet of casing for approximately $2.4 million in April 2004 to be held in inventory until needed.

Contract Drilling. Our drilling work is subject to many factors that influence the number of rigs we have working as well as the costs and revenues associated with that work. These factors include 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. We have not encountered major difficulty in hiring and keeping rig crews, but such shortages have occurred periodically in the past. At the end of the first quarter of 2004 we increased wages in some of our areas of drilling operations and implemented longevity pay incentives to help maintain our contract drilling labor base. If demand for drilling rigs increases rapidly in the future, shortages of experienced personnel may limit our ability to increase the number of rigs we could operate.

We currently do not have any shortages in drill pipe and drilling equipment. Due to the increasing cost of steel and increasing potential for shortages in the availability of new drill pipe within the industry, in the first quarter of 2004 we made a commitment to purchase approximately 275,000 feet of drill pipe for $9.3 million from three different suppliers by the end of 2004.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. The average rates received for our rigs during 2003 and 2004 were at a low of $7,275 per day in February of 2003. Natural gas and oil prices have been rising since the second quarter of 2003 through the first quarter of 2004 and both demand for our rigs and dayrates have continued to improve. In the first quarter of 2004 the average dayrate we received was approximately $8,250 per day. The average use of our rigs in the first quarter of 2004 was 81.7 rigs (93%) compared with 50.8 rigs (68%) for the first quarter of 2003. Based on the average utilization of our rigs in the first quarter of 2004, a $100 per day change in dayrates has a $8,170 per day ($2,982,000 annualized) change in our pre-tax operating cash flow. Utilization and dayrates for our drilling rigs will depend mainly on the price of natural gas.

Our contract drilling subsidiary provides drilling services for our exploration and production subsidiaries. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. During the first quarter of 2003 and 2004, we drilled 12 and 8 wells, respectively for our exploration and production subsidiary. Per regulations provided by the Securities and Exchange Commission, the profit received by our contract drilling segment of $330,000 and $929,000 during the first quarter of 2003 and 2004, respectively, was used to reduce 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 December 8, 2003, we acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the three years following the acquisition. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and an equipment yard in and near Borger, Texas.

For our contract drilling operations during the first quarter of 2004, we incurred $9.7 million in capital expenditures. For the year 2004, we have budgeted capital expenditures of approximately $30 million for our contract drilling operations.

On April 20, 2004, we announced that we have reached an agreement to buy two drilling rigs and related equipment for $5.5 million. The rigs are rated at 850 and 1,000 horsepower respectively and are ready for work with depth capacities from 12,000 to 15,000 feet. The rigs are to be added into our Rocky Mountain division, bringing the total rigs in that division to 10. Closing of this transaction is expected to occur on or before May 7, 2004. With this acquisition, our total rig fleet will consist of 90 drilling rigs, with the 91st rig being built and expected to be operational in 30 days.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 10 oil and natural gas limited partnerships which were formed privately and publicly. The partnership's revenues and costs are shared under formulas prescribed in each 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 2003, the total paid to us for all of these fees was $873,000. We expect the fees to be about the same in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

We own a 40% equity interest in Superior Pipeline Company LLC, an Oklahoma Limited Liability Company. Superior is a natural gas gathering and processing company. Our investment, including our share of the equity in the earnings of that company, totaled $3.3 million at March 31, 2004 and is reported in other assets in our balance sheet. During the first quarter of 2004, Superior Pipeline Company LLC purchased $1.1 million of our natural gas production and paid $11,000 for our natural gas liquids. We paid this company $5,000 for gathering and compression services in the first quarter.

We also own a 16.7% limited partnership interest in Eagle Energy Partnership I, L.P. ("Eagle") for $2.5 million. Eagle is engaged in the purchase and sale of natural gas, electricity (or similar electricity based products), future commodities, and the performance of scheduling and nomination services for both energy related commodities and similar energy management functions. Eagle marketed approximately 48% of the natural gas volumes we sell for ourselves and third parties in the first quarter of 2004.

Critical Accounting Policies. We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties is limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (10% discount rate) of estimated future net revenues from proved reserves, based on period-end oil and natural gas prices adjusted for hedging, plus the lower of cost or estimated fair value of unproved properties not included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down cannot be reversed even if prices subsequently recover.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices on March 31, 2004 ($5.27 per Mcf for natural gas and $34.39 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas prices remain erratic and any significant declines below prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

The value of our oil and natural gas reserves is used to determine the borrowing base under our loan agreement with our banks. This amount is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimates of oil and natural gas reserves requires extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to these estimates does not reduce the subjectivity and changing nature of reserve estimates. Indeed, the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves.

We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the natural gas balancing position on wells in which we have an imbalance are not material.

Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and enhancements are capitalized while repairs and maintenance are expensed. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances suggest the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment.

We recognize revenues and expense generated from “daywork” drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

NEW ACCOUNTING PRONOUNCEMENTS

On January 17, 2003, the FASB issued FASB Interpretation No. 46, “Consolidation of Variable Interest Entities, an interpretation of ARB 51” (“FIN 46”). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights (“variable interest entities” or “VIEs”) and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties.

FIN 46, as amended, was effective for us in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, primarily Eagle Energy Partnership I, L.P., did not have an impact on our financial position or results of operations or cash flows. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, FIN 46 and the amendment of FIN 46 were effective for us, as amended, in the quarter ending March 31, 2004. We evaluated FIN 46 and FIN 46(R) with regard to these types of entities in which we have an ownership interest and there was no material impact to the financial position, results of operations or cash flows from the adoption of FIN 46 and FIN 46(R).

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the notes to our financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, we, like many other oil and gas companies, have included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective. Our results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

At March 31, 2003 and 2004, we had undeveloped leaseholds of approximately $14.2 million and $16.4 million, respectively that would be classified on our balance sheets as "intangible undeveloped leasehold" and developed leaseholds of an estimated $20.0 million and $129.1 million, respectively that would be classified as "intangible developed leasehold" if the interpretations were applied. This classification would require us to make the disclosures set forth under FAS 142 related to these interests.

The Financial Accounting Standards Emerging Issues Task Force (EITF) has recently issued proposed FASB Staff Position (FSP) FAS 141-a and 142-a "Interaction of FASB Statements No. 141, *Business Combinations*, and No. 142, *Goodwill and Other Intangible Assets*, and EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets." The proposed FSP would amend FAS 141 and FAS 142 to remove some inconsistencies between the standards related to the proper classification of assets related to mineral rights.

On April 30, 2004, the FASB directed the FASB staff to issue the FSP and the guidance in the FSP shall be applied to the first reporting period beginning after April 29, 2004. Under the FSP certain use rights may have characteristics of tangible assets, so we intend to continue to classify our oil and natural gas mineral extraction rights as tangible oil and gas properties.

SAFE HARBOR STATEMENT

Statements in this document as well as information contained in written material, press releases and oral statements issued by or for us contain, or may contain, certain "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included in this document which address activities, events or developments which we expect or expect will or may occur in the future are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions are also intended to identify forward-looking statements. These forward-looking statements include, among others, such things as:

- the amount and nature of future capital expenses;
- wells to be drilled or reworked;
- oil and natural gas prices to be received and demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of our oil and natural gas reserves;
- expansion and growth of our business and operations;
- availability of drilling rigs and rig related equipment;
- drilling rig use, revenues and costs; and
- availability of qualified labor.

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

- the risk factors discussed in this document;
- general economic, market or business conditions;
- the nature or lack of business opportunities that may be presented to and pursued by us;
- demand for land drilling services;
- changes in laws or regulations; and
- other reasons, most of which are beyond our control.

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.

RESULTS OF OPERATIONS

First Quarter 2004 versus First Quarter 2003

Provided below is a comparison of selected operating and financial data for the first quarter of 2004 versus the first quarter of 2003:

	First Quarter 2003	First Quarter 2004	Percent Change
Total Revenue	$ 68,564,000	$ 101,900,000	49%
Income Before Change in Accounting Principle	$ 12,659,000	$ 15,507,000	22%
Net Income	$ 13,984,000	$ 15,507,000	11%
Oil and Natural Gas:			
Revenue	$ 33,248,000	$ 37,990,000	14%
Average natural gas price (Mcf)	$ 5.96	$ 4.90	(18%)
Average oil price (Bbl)	$ 30.40	$ 30.63	1%
Natural gas production (Mcf)	4,855,000	6,294,000	30%
Oil production (Bbl)	114,000	215,000	89%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.08	$ 1.33	23%
Depreciation, depletion and amortization	$ 6,047,000	$ 10,177,000	68%
Drilling:			
Revenue	$ 34,566,000	$ 63,214,000	83%
Percentage of revenue from daywork contracts	95%	100%	
Average number of rigs in use	50.8	81.7	61%
Average dayrate on daywork contracts	$ 7,317	$ 8,252	13%
Depreciation	$ 4,894,000	$ 7,464,000	53%
General and Administrative Expense	$ 2,450,000	$ 2,771,000	13%
Interest Expense	$ 211,000	$ 417,000	98%
Average Interest Rate	2.10%	2.19%	4%
Average Long-Term Debt Outstanding	$ 31,612,000	$ 56,019,000	77%

Oil and natural gas revenues increased due to increases in both oil and natural gas produced and to a lesser extent from an increase in oil prices between the first quarter of 2004 and the first quarter of 2003. A reduction in natural gas prices partially offset the increases. PetroCorp Incorporated was acquired on January 30, 2004 and its production is included in our operating results subsequent to the acquisition date. Oil production was up 89% between the comparative quarters. Approximately 69% of the increase was from the production added through the PetroCorp Incorporated acquisition. Natural gas production was up 30% between the comparative quarters. Approximately 49% of the increase in natural gas production was from wells acquired through the PetroCorp Incorporated acquisition. The remainder of the increase in production for both oil and natural gas came from wells added through our development drilling program. Total operating cost increased in the first quarter of 2004 when compared with the first quarter of 2003 due to mainly from the acquisition of PetroCorp Incorporated and to a lesser extent from costs associated with workovers. PetroCorp Incorporated has historically experienced higher operating cost per equivalent barrel due to the types of wells under production and the reserve base being more toward oil. Gross production taxes which are based on a percentage of revenues were also higher. Our total depreciation, depletion and amortization ("DD&A) increased due to the increase in equivalent volumes produced and an increase in our DD&A rate per Mcfe. The acquisition of PetroCorp Incorporated was made at a higher cost per equivalent volumes than we have previously experienced through both our drilling program and from other acquisitions on average. During 2003, we also experienced higher cost per Mcfe for the discovery of new reserves through our development drilling program.

Contract drilling revenues increased between the comparative quarters due to increases in demand for our drilling rigs and increases in dayrates. Natural gas prices remained between $4.00 and $5.50 through most of 2003 causing an increase in demand for our rigs. Dayrates, which typically increase after the increase in demand for rigs, also started increasing in the second quarter of 2003 and have continued to steadily increase throughout the first quarter of 2004. Along with the increase in demand we also added 12 drilling rigs with the acquisition of SerDrilco, Inc. in December of 2003 contributing to the increase in total drilling revenues and operating cost. We did not drill any turnkey or footage wells in the first quarter of 2004. Approximately 5% of our total drilling revenues in the first quarter of 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Contract drilling depreciation increased due to the acquisition of 12 rigs in the fourth quarter of 2003.

General and administrative expense was higher in the first quarter of 2004 due to increases in employee, insurance and general office administrative costs. Our total interest expense was higher due to the additional debt incurred from the PetroCorp Incorporated acquisition. Income tax expense increased primarily due to the increase in income before income taxes.

Net income in the first quarter of 2003 includes $1.3 million of income due to a change in accounting principle for the implementation of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143).

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks due to changes in commodity prices. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices have been volatile and such volatility is expected to continue.

In an effort to try and reduce the impact of price fluctuations, over the past several years we periodically have used hedging strategies to hedge the prices 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 under Item 2.

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 in timely alerting them to material information required to be included in our periodic SEC filings relating to the company (including its consolidated subsidiaries).

There were no changes in the company's internal controls or in other factors that could significantly affect these internal controls subsequent to the date of our most recent evaluation.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

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 and Reports on Form 8-K

(a) 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.

(b) On January 14, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced the retirement of Earle Lamborn from Unit Corporation and his resignation from Unit's Board of Directors effective January 15, 2004.

On February 2, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced that Unit Corporation has closed its acquisition of PetroCorp Incorporated. Unit also announced that on January 30, 2004, it had entered into a new $150 million credit facility in place of its existing loan agreement.

On February 18, 2004, we filed a report on Form 8-K under item 7 and 12. This report announced our earnings for the quarter and year ended December 31, 2003 in an attached exhibit.

On March 3, 2004, we filed a report on Form 8-K/A under item 7. This report amended Form 8-K filed February 2, 2004 to include the historical financial statements of PetroCorp Incorporated and the related pro forma financial information.

On April 19, 2004, we filed a report on Form 8-K under item 7, 9 and 12. This report announced our earnings for the quarter ended March 31, 2004 in an attached exhibit.

On April 20, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced that we have reached an agreement to buy two drilling rigs and related equipment for $5.5 million. Closing of this transaction is expected to occur on or before May 7, 2004.

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 4, 2004 By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chief Executive Officer,
and Director

Date: May 4, 2004 By: /s/ David T. Merrill

DAVID T. MERRILL
Chief Financial Officer and
Treasurer

Exhibit 15

May 4, 2004

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Commissioners:

We are aware that our report dated April 19, 2004 on our review of interim financial information of Unit Corporation for the three month period ended March 31, 2003 and 2004 and included in the Company's quarterly report on Form 10-Q for the quarter ended March 31, 2004 is incorporated by reference in its registration statements on Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166 and 333-39584) and Form S-3 (File No.’s 333-83551 and 333-99979).

Yours very truly,

PricewaterhouseCoopers LLP

Exhibit 31.1

TRANSITIONAL FORM OF SECTION 302 CERTIFICATIONS FOR ACCELERATED FILER

I, John G. Nikkel, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(c) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2004

/s/ John G. Nikkel
JOHN G. NIKKEL
Chief Executive Officer,
and Director

Exhibit 31.2

TRANSITIONAL FORM OF SECTION 302 CERTIFICATIONS FOR ACCELERATED FILER

I, David T. Merrill, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(c) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2004

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

Exhibit 32

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of March 31, 2004 and March 31, 2003 and for the quarters ended March 31, 2004 and 2003.

Dated: May 4, 2004

By: /s/ John G. Nikkel

John G. Nikkel
Chief Executive Officer

Dated: May 4, 2004

By: /s/ David T. Merrill

David T. Merrill
Chief Financial Officer and
Treasurer

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-Q or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.