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 September 30, 2002
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.)**

1000 Kensington Tower I, 7130 South Lewis, 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 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	**43,336,700**
Class	**Outstanding at November 4, 2002**

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, 2001	September 30, 2002
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 391	$ 580
Accounts receivable	33,886	32,236
Materials and supplies	5,358	9,617
Income tax receivable	3,198	-
Other	3,761	5,080
Total current assets	46,594	47,513
Property and Equipment:		
Total cost	666,861	821,213
Less accumulated depreciation, depletion, amortization and impairment	304,643	330,903
Net property and equipment	362,218	490,310
Other Assets	8,441	17,882
Total Assets	$ 417,253	$ 555,705
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term liabilities and debt	$ 1,893	$ 1,356
Accounts payable	16,292	17,374
Accrued liabilities	10,856	12,690
Total current liabilities	29,041	31,420
Long-Term Debt	31,000	24,500
Other Long-Term Liabilities	4,110	4,419
Deferred Income Taxes	73,940	80,980
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, 36,006,267 and 43,336,700 shares issued, respectively	7,201	8,667
Capital in excess of par value	141,977	263,981
Accumulated other comprehensive income	-	-
Retained earnings	130,280	141,738
Treasury Stock, at cost, 30,000 shares	(296)	-
Total shareholders' equity	279,162	414,386
Total Liabilities and Shareholders' Equity	$ 417,253	$ 555,705

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	**2002**	**2001**	**2002**
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 50,690	$ 31,589	$131,026	$ 84,144
Oil and natural gas	17,410	16,357	77,652	46,986
Other	299	326	1,251	625
Total revenues	68,399	48,272	209,929	131,755
Expenses:				
Contract drilling:				
Operating costs	24,978	24,350	71,405	63,619
Depreciation and amortization	3,872	4,178	10,693	9,917
Oil and natural gas:				
Operating costs	5,332	5,169	17,337	15,278
Depreciation, depletion and amortization	6,641	6,142	16,461	17,399
General and administrative	1,731	2,180	6,565	6,222
Interest	675	231	2,366	747
Total expenses	43,229	42,250	124,827	113,182
Income Before Income Taxes	25,170	6,022	85,102	18,573
Income Tax Expense:				
Current	3,251	(285)	10,990	75
Deferred	6,288	2,599	21,261	7,040
Total income taxes	9,539	2,314	32,251	7,115
Net Income	$ 15,631	$ 3,708	$ 52,851	$ 11,458
Net Income Per Common Share:				
Basic	$ .43	$ 0.09	$ 1.47	$ 0.31
Diluted	$ .43	$ 0.09	$ 1.46	$ 0.30

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

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

	Nine Months Ended September 30, 2001	Nine Months Ended September 30, 2002
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 52,851	$ 11,458
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion, and amortization	27,642	27,789
Deferred tax expense	21,261	7,040
Other	1,816	373
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(6,652)	1,347
Accounts payable	7,118	6,548
Other - net	72	(281)
Net cash provided by operating activities	104,108	54,274
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (Note 3)	(83,824)	(48,825)
Proceeds from disposition of assets	2,125	1,630
Other-net	(498)	523
Net cash used in investing activities	(82,197)	(46,672)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(16,000)	(6,500)
Net payments of notes payable and other long-term debt	-	(22)
Proceeds from stock sales (Note 3)	606	213
Acquisition of treasury stock	(175)	-
Book overdrafts	(6,082)	(1,104)
Net cash used in financing Activities	(21,651)	(7,413)
Net Increase in Cash and Cash Equivalents	260	189
Cash and Cash Equivalents, Beginning of Year	726	391
Cash and Cash Equivalents, End of Period	$ 986	$ 580

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 September 30,		Nine Months Ended September 30,	
	2001	2002	2001	2002
	(In thousands)			
Net Income	$ 15,631	$ 3,708	$ 52,851	$ 11,458
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	549	-	1,100	-
Adjustment Reclassification - Derivative Settlements	(652)	-	(652)	-
Comprehensive Income	$ 15,528	$ 3,708	$ 53,299	$ 11,458

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 wholly owned subsidiaries (the “Company”) and have been prepared pursuant to 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.

Results for the three and nine months ended September 30, 2002 are not necessarily indicative of the results to be realized during the full year. The condensed financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2001. 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. Pursuant to 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.

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
For the Three Months Ended September 30, 2001:			
Basic earnings per common share	$ 15,631,000	35,999,000	$ 0.43
Effect of dilutive stock options	-	236,000	
Diluted earnings per common share	$ 15,631,000	36,235,000	$ 0.43
For the Three Months Ended September 30, 2002:			
Basic earnings per common share	$ 3,708,000	39,804,000	$ 0.09
Effect of dilutive stock options	-	267,000	
Diluted earnings per common share	$ 3,708,000	40,071,000	$ 0.09

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended September 30, 2001 and 2002 because the option exercise prices were greater than the average market price of common shares:

	2001	2002
Options	170,000	179,000
Average exercise price	$ 16.38	$ 17.23

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
For the Nine Months Ended September 30, 2001:			
Basic earnings per common share	$ 52,851,000	35,961,000	$ 1.47
Effect of dilutive stock options	-	295,000	
Diluted earnings per common share	$ 52,851,000	36,256,000	$ 1.46
For the Nine Months Ended September 30, 2002:			
Basic earnings per common share	$ 11,458,000	37,330,000	$ 0.31
Effect of dilutive stock options	-	264,000	
Diluted earnings per common share	$ 11,458,000	37,594,000	$ 0.30

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the nine months ended September 30, 2001 and 2002 because the option exercise prices were greater than the average market price of common shares:

	2001	2002
Options	153,000	179,000
Average exercise price	$ 16.79	$ 17.23

NOTE 3 – ACQUISITION OF EQUIPMENT AND DRILLING COMPANIES

On August 15, 2002, we completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company. Both of these acquisitions were stock purchase transactions. Unit issued 6,819,748 shares of common stock and paid $3,813,053 for all the outstanding shares of CREC Rig Acquisition Company and issued 400,252 shares of common stock and paid $686,947 for all the outstanding shares of CDC Drilling Company. The assets of the acquired companies included twenty drilling rigs, spare drilling equipment and vehicles. What we paid in both transactions was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities of Unit's Consolidated Condensed Statement of Cash Flows.

The calculation and allocation of the total consideration paid for the acquisition are as follows (in thousands):

Calculation of Consideration Paid:

Unit Corporation common stock (7,220,000 shares at $16.96556 per share)	$ 122,491
Cash	4,500
Total consideration	$ 126,991

Allocation of Total Consideration Paid:

Drilling Rigs	$ 112,994
Spare Drilling Equipment	3,500
Vehicles	636
Goodwill	9,861
Total consideration	$ 126,991

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, 2001 are as follow:

	Year Ended December 31, 2001	**Nine Months Ended September 30, 2001**	**Nine Months Ended September 30, 2002**
Revenues	$ 311,104,000	$ 246,650,000	$ 159,924,000
Net Income	$ 70,457,000	$ 58,928,000	$ 8,534,000
Net Income per Common Share (Diluted)	$ 1.62	$ 1.36	$ 0.20

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 - NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2002, we adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142). For goodwill and intangible assets already recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. The unamortized balance of goodwill, all of which relates to our drilling segment, was $5,088,000 at January 1, 2002 and $14,950,000 at September 30, 2002. Goodwill increased in the third quarter of 2002 as a result of the acquisitions discussed in Note 3. We previously expensed $243,000 annually for the amortization of goodwill. The impact from the adoption of FAS 142 on our financial position or results of operations was not material to the current and prior periods.

On January 1, 2002, we adopted Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144). This statement supersedes Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. The impact from the adoption of FAS 144 on our financial position or results of operations was not material.

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002 (January 1, 2003 for us) and 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). We are currently evaluating our oil and natural gas properties to determine the impact of the adoption of FAS 143 on our financial position and results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Corrections" (FAS 145). FAS 145 is effective for fiscal years beginning after May 15, 2002. This statement eliminates an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. We do not expect the adoption of FAS 145 to have a material effect on our financial position, results of operations or cashflows.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, “Accounting for Cost Associated with Exit or Disposal Activities” (FAS 146). FAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. FAS 146 nullifies Emerging Issues Task Force Issue No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” We do not expect the adoption of FAS 146 to have a material effect on our financial position, results of operations or cashflow.

NOTE 5 - INDUSTRY SEGMENT INFORMATION

Unit 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. Unit has natural gas production in Canada, which is not significant. Information regarding Unit’s operations by industry segment for the three and nine month periods ended September 30, 2001 and 2002 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2002	2001	2002
	(In thousands)			
Revenues:				
Contract drilling	$ 50,690	$ 31,589	$ 131,026	$ 84,144
Oil and natural gas	17,410	16,357	77,652	46,986
Other	299	326	1,251	625
	$ 68,399	$ 48,272	$ 209,929	$ 131,755
Operating Income (1):				
Contract drilling	$ 21,840	$ 3,061	$ 48,928	$ 10,608
Oil and natural gas	5,437	5,046	43,854	14,309
	27,277	8,107	92,782	24,917
General and administrative expense	(1,731)	(2,180)	(6,565)	(6,222)
Interest expense	(675)	(231)	(2,366)	(747)
Other income - net	299	326	1,251	625
	$ 25,170	6,022	$ 85,102	$ 18,573

(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.

REPORT OF REVIEW BY INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and subsidiaries as of September 30, 2002, and the related consolidated condensed statements of operations and comprehensive income for the three and nine month periods ended September 30, 2002 and 2001 and cash flows for the nine month period ended September 30, 2002 and 2001. These 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 financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with generally accepted auditing standards, the consolidated balance sheet as of December 31, 2001, and the related consolidated statements of operations, stockholder's equity and cash flows for the year then ended (not presented herein); and in our report, dated February 20, 2002, 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, 2001, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
October 23, 2002

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 two principal subsidiaries and borrowings under our bank loan agreement. At September 30, 2002, we had cash totaling $580,000 and we had borrowed $24.5 million of the $40.0 million we have elected to have available under our loan agreement.

The following is a summary of certain financial information on September 30, 2002 and for the nine months ended September 30, 2002:

Working capital	$ 16,093,000
Net income	$ 11,458,000
Net cash provided by operating activities	$ 54,274,000
Long-term debt	$ 24,500,000
Shareholders' equity	$ 414,386,000
Ratio of long-term debt to total capitalization	6%

The following table summarizes certain operating information for the first nine months of 2001 and 2002:

	2001	2002	Percent Change
Oil production (Bbls)	374,000	347,000	(7%)
Natural gas production (Mcf)	14,437,000	14,360,000	(1%)
Average oil price received	$ 25.59	$ 20.92	(18%)
Average natural gas price received	$ 4.54	$ 2.59	(43%)
Average number of our drilling rigs in use during the period	48.8	36.2	(26%)

Our Bank Loan Agreement. On July 24, 2001, we signed a $100 million bank loan agreement. At our election, the amount currently available for us to borrow is $40 million. Although the current value of our assets would have allowed us to have access to the full $100 million, we elected to set the loan commitment at $40 million to reduce our financing costs since we are charged a facility fee of .375 of 1 percent on the amount available but not borrowed.

Each year, on April 1 and October 1, our banks redetermine the loan value of our assets. This value is mainly based on an amount equal to 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. Our loan agreement provides for a revolving credit facility, which ends on May 1, 2005 followed by a three-year term loan. Borrowing under our loan agreement totaled $30.0 million at December 31, 2001 and $24.9 million on October 23, 2002.

Borrowings under the revolving credit facility bear interest at the Chase Manhattan Bank, N.A. prime rate ("Prime Rate") or the London Interbank Offered Rates ("Libor Rate") plus 1.00 to 1.50 percent depending on the level of debt as a percentage of the total loan value. After May 1, 2005, borrowings under the loan agreement bear interest at the Prime Rate or the Libor Rate plus 1.25 to 1.75 percent depending on the level of debt as a percentage of the total loan value. In addition, the loan agreement allows us to select, between the date of the agreement and 3 days before the start of the term loan, a fixed rate for the amount outstanding under the credit facility. Our ability to select the fixed rate option is subject to several conditions, all of which are set out in the loan agreement.

The interest rate on our bank debt was 2.94 percent and 2.96 percent at September 30, 2002 and October 23, 2002, respectively. At our election, any portion of our outstanding bank debt may be fixed at the Libor Rate, as adjusted depending on the level of our debt as a percentage of the amount available for us to borrow. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the balance of our bank debt being subject to the Prime Rate. During any Libor Rate funding period, we may not pay any part of the outstanding principal balance which is subject to the Libor Rate. Borrowings subject to the Libor Rate were $23.0 million at September 30, 2002 and October 23, 2002.

The loan agreement also requires us to maintain:

- consolidated net worth of at least $125 million;
- a current ratio of not less than 1 to 1;
- a ratio of long-term debt, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.2 to 1;
- a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1; and
- working capital provided by operations, as defined in the loan agreement, cannot be less than $40 million in any year.

We are restricted from paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of our consolidated net income from the preceding fiscal year and we can pay dividends only if our working capital provided from our operations during the preceding year is equal to or greater than 175 percent of current maturities of long-term debt at the end of the preceding year. We also cannot incur additional debt except in 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 is prohibited unless it is in favor of our banks.

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. We entered into a collar contract covering approximately 25 percent of our daily oil production from November 1, 2000 through February 28, 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

During the second quarter of 2001, we entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, we entered into two natural gas collar contracts for approximately 38 percent of our September thru November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling of $ 3.68 and the other contract had a ceiling of $4.25. During the third quarter of 2001, the collar contract increased natural gas revenues by $1,049,000 and for the nine months ended September 30, 2001 the collar contract increased natural gas revenues by $1,565,000. The October and November 2001 collar was recognized on our September 30, 2001 balance sheet at $448,000, net of tax, in accumulated other comprehensive income. On April 30, 2002, we entered into a collar contract covering approximately 19 percent of our natural gas production for the periods of April 1, 2002 thru October 31, 2002. The collar has a floor of $3.00 and a ceiling of $3.98. During the third quarter of 2002, our natural gas hedging transactions increased natural gas revenues by $40,300 and the remaining month contract had no value at September 30, 2002.

Self-Insurance. Unit is self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. Given the recent tightening in the insurance market our self-insurance levels have significantly increased. Effective August 1, 2002, our exposure (i.e. our deductible or retention) per occurrence range 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 Unit against liability from all potential consequences.

Our Oil and Natural Gas Operations. Natural gas comprises 91 percent 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.

Based on our 2002 first nine month production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $149,000 per month ($1,788,000 annualized) change in our pre-tax cash flow. Our first nine month 2002 average natural gas price was $2.59 compared to an average natural gas price of $4.54 received in the first nine months of 2001. A $1.00 per barrel change in our oil price would have a $36,000 per month ($432,000 annualized) change in our pre-tax cash flow. Our first nine months 2002 average oil price was $20.92 compared with an average oil price of $25.59 received in the first nine months of 2001.

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. Also, price declines can 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. Presently we believe that our buyers will be able to perform their commitments to us. However, we will continue to evaluate the information available to us about these buyers in an effort to reduce any possible future adverse impact to us.

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 to incur such costs. We drilled 62 wells in the first nine months of 2002 compared to 94 wells in the first nine months of 2001. Through the first nine months of 2002 we incurred $31.2 million of the $45 million in capital expenditures we expect to make for exploration, development drilling and acquisition of oil and natural gas properties in 2002. Based on current prices, we plan to drill an estimated 100 wells in 2002

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 such 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. If demand for drilling rigs was to increase rapidly in the future, shortages of experienced personnel would limit our ability to increase the number of rigs we could operate. Through the first nine months of 2002 we incurred $8.7 million in capital expenditures for our drilling operation. For the year 2002, we anticipate spending approximately $12 million on our drilling operations excluding the acquisition discussed below.

Low oil and natural gas prices during most of the 1980's and 1990's reduced demand for domestic land contract drilling rigs. However, in the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when 52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001. Average use of our rigs in the first nine months of 2002 was 36.2 rigs compared with 48.8 rigs for the first nine months of 2001.

As demand for our rigs increased during 2001 so did the dayrates we received. Our average dayrate reached $11,142 by September of 2001. However, as demand began to decrease, so did our rates. Our average dayrate in the first nine months of 2002 was $7,847 compared to $10,011 for the first nine months of 2001. Based on the average utilization of our rigs in the first nine months of 2002, a $100 per day change in dayrates has a $3,600 per day ($1,314,000 annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. The profit received by our contract drilling segment of $1,617,000 and $677,000 in the first nine months of 2001 and 2002, 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.

Acquisitions. On August 15, 2002 we completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company, which included twenty drilling rigs, spare drilling equipment and vehicles, for 7.22 million shares of our common stock and $4.5 million in cash. All of the rigs are operational and range in horsepower from 650 to 2,000 with 15 having a horsepower rating of 1,000 or more. Depth capacities range from 12,000 to 25,000 feet and twelve of the rigs are SCR electric. These agreements also give us the exclusive first option to purchase any additional rigs constructed by one of the sellers within the next three years. The addition of these twenty rigs brought our fleet to 75, 74 of which are capable of operating.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for eighteen oil and natural gas 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 2001, the total paid to us for all of these fees was $1,107,000 and we expect the fees to be about the same in 2002. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

At September 30, 2002, we owned a 40 percent equity interest in a natural gas gathering and processing company. Our investment including our share of the equity in the earnings of this company totaled $1.5 million at September 30, 2002. From time to time we may guarantee the debt of this company. However, as of September 30, 2002 and October 23, 2002, we were not guaranteeing any of the debt of this company.

One of our subsidiaries owns 4,949,500 shares of common stock and 1,800,000 warrants of Shenandoah Resources Ltd. ("Shenandoah"), a Canadian oil and natural gas exploration and production company. In the second quarter of 2002 Shenandoah obtained an order under Canadian Law protecting it from its creditors while it worked out a financial restructuring plan. On July 17, 2002, Longbow Energy Corporation ("LongBow") and Shenandoah jointly announced that they have executed a Letter of Intent whereby LongBow would acquire all of the issued and outstanding shares of Shenandoah and settle the outstanding claims of Shenandoah's secured and unsecured creditors. In August the assets of Shenandoah were foreclosed and the anticipated merger with LongBow was cancelled. As a result of the foreclosure, our investment of $346,000 in Shenandoah was written off.

Outlook. Both of our operating segments are extremely dependent on natural gas prices, since the prices affect not only our production revenues, but also the future demand and rates for our contract drilling services. On October 23, 2002, the Nymex Henry Hub average contract settle price for the next twelve months was $4.14 and, we anticipate that if natural gas prices continue at that level, there will be increased demand for our rigs and upward movement on the rates we receive for contract drilling services.

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 percent discount rate) of estimated future net revenues from proved reserves, based on period-end oil and natural gas prices, plus the lower of cost or estimated fair value of unproved properties 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 stockholders' 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 in effect on September 30, 2002 ($3.39 per Mcf for natural gas and $28.26 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 quarter-end 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 decide the loan value under our loan agreement. This value is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimate of oil and natural gas reserves require extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such 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 betterments 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 such estimates could cause us to reduce the carrying value of our property and equipment.

We recognize revenues generated for “daywork” drilling contracts as the services are performed, which is similar to the percentage of completion method. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well, so revenues and expenses are recognized using the completed contract method. 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.

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

Third Quarter 2002 versus Third Quarter 2001

Provided below is a comparison of selected operating and financial data for the third quarter of 2002 verses the third quarter of 2001:

	Third Quarter 2001	Third Quarter 2002	Percent Change
Total Revenue	$ 68,399,000	$ 48,272,000	(29%)
Net Income	$ 15,631,000	$ 3,708,000	(76%)
Oil and Natural Gas:			
Revenue	$ 17,410,000	$ 16,357,000	(6%)
Average natural gas price (Mcf)	$ 2.79	$ 2.71	(3%)
Average oil price (Bbl)	$ 23.92	$ 22.99	(4%)
Natural gas production (Mcf)	4,929,000	4,707,000	(5%)
Oil production (Bbl)	122,000	120,000	(1%)
Operating profit (revenue less operating costs)	$ 12,078,000	$ 11,188,000	(7%)
Operating margin	69%	68%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.88	$ 1.06	20%
Depreciation, depletion and amortization	$ 6,641,000	$ 6,142,000	8%
Drilling:			
Revenue	$ 50,690,000	$ 31,589,000	(38%)
Percentage of revenue from daywork contracts	100%	92%	
Average number of rigs in use	50.6	42.5	(16%)
Average dayrate on daywork contracts	$ 10,964	$ 7,529	(31%)
Operating profit (revenue less operating costs)	$ 25,712,000	$ 7,239,000	(72%)
Operating margin	51%	23%	
Depreciation	$ 3,872,000	$ 4,178,000	8%
General and Administrative Expense	$ 1,731,000	$ 2,180,000	26%
Interest Expense	$ 675,000	$ 231,000	(66%)
Average Interest Rate	5.0%	3.1%	(38%)
Average Long-Term Debt Outstanding	$ 45,965,000	$ 22,610,000	(51%)

Oil and natural gas revenues, operating profits and operating profit margins were all negatively affected by lower prices received for both oil and natural gas between the third quarter of 2002 and the third quarter of 2001. We also experienced a decrease in our oil and natural gas production volumes as declines on wells previously drilled have exceeded production from new wells drilled in the current year. Total operating cost decreased due mainly to lower workover expense in the third quarter of 2002 when compared to 2001. In the third quarter of 2001, we wrote down our investment in Shenandoah Resources, Inc. by $1.6 million so, depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties decreased in the third quarter of 2002. The decrease was partially offset by a write down of the remaining amount we had invested in Shenandoah Resources, Inc. of $346,000 in the third quarter of 2002 and an increase in our DD&A rate per Mcfe. We are experiencing higher cost per Mcfe for the discovery of new reserves through our development drilling program resulting in an increase in the DD&A rate.

Reduced natural gas prices, especially in the fourth quarter of 2001 and the first quarter of 2002, caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. As a result, operating margins declined between the third quarter of 2002 and the third quarter of 2001. Approximately 8 percent of our total drilling revenues in the third quarter of 2002 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Less than one percent of our total drilling revenues came from footage and turnkey contracts in the third quarter of 2001. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002. The increase was partially offset by lower rig use.

General and administrative expense was higher in the third quarter of 2002 due to increases in insurance expense and higher labor costs. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt.

Nine Months 2002 versus Nine Months 2001

Provided below is a comparison of selected operating and financial data for the first nine months of 2002 verses the first nine months of 2001:

	First Nine Months of 2001	First Nine Months of 2002	Percent Change
Total Revenue	$ 209,929,000	$ 131,755,000	(37%)
Net Income	$ 52,851,000	$ 11,458,000	(78%)
Oil and Natural Gas:			
Revenue	$ 77,652,000	$ 46,986,000	(39%)
Average natural gas price (Mcf)	$ 4.54	$ 2.59	(43%)
Average oil price (Bbl)	$ 25.59	$ 20.92	(18%)
Natural gas production (Mcf)	14,437,000	14,360,000	(1%)
Oil production (Bbl)	374,000	347,000	(7%)
Operating profit (revenue less operating costs)	$ 60,315,000	$ 31,708,000	(47%)
Operating margin	78%	67%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.88	$ 1.03	17%
Depreciation, depletion and amortization	$ 16,461,000	$ 17,399,000	6%
Drilling:			
Revenue	$ 131,026,000	$ 84,144,000	(36%)
Percentage of revenue from daywork contracts	100%	91%	
Average number of rigs in use	48.8	36.2	(26%)
Average dayrate on daywork contracts	$ 10,011	$ 7,847	(22%)
Operating profit (revenue less operating costs)	$ 59,621,000	$ 20,525,000	(66%)
Operating margin	46%	24%	
Depreciation	$ 10,693,000	$ 9,917,000	(7%)
General and Administrative Expense	$ 6,565,000	$ 6,222,000	(5%)
Interest Expense	$ 2,366,000	$ 747,000	(68%)
Average Interest Rate	6.1%	3.1%	(49%)
Average Long-Term Debt Outstanding	$ 48,184,000	$ 24,907,000	(48%)

Oil and natural gas revenues, operating profits and operating profit margins were all negatively affected by lower prices received for both oil and natural gas between the first nine months of 2002 and the first nine months of 2001. Both natural gas and oil production also had declines between the comparative nine month period as production declines from wells previously drilled have not been completely replaced by production from new wells drilled over the past year. Total operating cost decreased primarily from lower gross production taxes, since the tax is based on a percentage of oil and natural gas revenues. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased due to an increase in our DD&A rate per Mcfe. We are experiencing higher cost per Mcfe for the discovery of new reserves through our development drilling program, resulting in an increase in the DD&A rate. The increase in our DD&A expense was partially offset by a $1.6 million write down of our investment in Shenandoah Resources, Inc. recorded in the third quarter of 2001.

Reduced natural gas prices, especially in the fourth quarter of 2001 and the first quarter of 2002, caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. As a result, operating margins and total operating cost both declined between the first nine months of 2002 and the first nine months of 2001. Approximately 9 percent of our total drilling revenues in the first nine months of 2002 came from footage and turnkey contracts, which had profit margins less than our daywork contracts. Less than one percent of our total drilling revenues came from footage and turnkey contracts in the first nine months of 2001. Contract drilling depreciation decreased due to lower rig use, but the decrease was partially offset by additional depreciation incurred from the 20 rigs acquired in August of 2002.

General and administrative expense declined for the first nine months of 2002 when compared with the first nine months of 2001. The 2001 General and administrative expense was higher because we recorded $1.3 million in additional employee benefit expenses for the present value of the separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. This decline was partially offset by increased insurance and employment cost incurred. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt.

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, the prices we have received for our oil and natural gas production 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 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.

Item 4. Controls and Procedures

Within the 90 days prior to the date of 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 pursuant to Exchange Act Rule 13a-14. 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 significant 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 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

In accordance with Section 10A(i)(2) of the Securities Exchange Act of 1934, as added by Section 202 of the Sarbanes-Oxley Act of 2002, we are responsible for disclosing any non-audit services approved by our Audit Committee (the "Committee") to be performed by PricewaterhouseCoopers LLP, who is our external auditor. Non-audit services are defined in the Act as services other than those provided in connection with an audit or a review of the financial statements of Unit. The Committee has approved the engagement of PricewaterhouseCoopers LLP to provide non-audit services for due diligence related to any potential acquisitions.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

15 Letter re: Unaudited Interim Financial Information.

(b) On August 15, 2002, we filed a report on Form 8-K under item 9. This report disclosed that the Principal Executive Officer, John G. Nikkel, and Principal Financial Officer, Larry D. Pinkston, of Unit Corporation, had filed with the SEC certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

On August 27, 2002, we filed a report on Form 8-K under items 2 and 7. This report announced that on August 15, 2002, Unit Corporation completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company.

On September 20, 2002, we filed a report on Form 8-K/A under item 7. This report included the combined financial statements of the CREC Rig Equipment Company and CDC Drilling Company and the pro forma financial information required with the Form 8-K filed on August 27, 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: November 5, 2002

By: /s/ John G. Nikkel

JOHN G. NIKKEL
President, Chief Executive Officer, Chief Operating Officer and Director

Date: November 5, 2002

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
Vice President, Chief Financial Officer and Treasurer

CERTIFICATIONS

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this

quarterly report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 5, 2002	By: /s/ John G. Nikkel
	JOHN G. NIKKEL President, Chief Executive Officer, Chief Operating Officer and Director

CERTIFICATIONS

I, Larry D. Pinkston, certify that:

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

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any

corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 5, 2002

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
Vice President, Chief
Financial Officer
and Treasurer

Exhibit 15

November 5, 2002

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

RE: Unit Corporation

Registration on Form S-8 and S-3

We are aware that our report dated October 23, 2002 on our review of interim financial information of Unit Corporation for the three and nine month periods ended September 30, 2002 and included in the Company's Form 10-Q for the quarter ended September 30, 2002 is incorporated by reference in the Company's 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).

PricewaterhouseCoopers LLP