F O R M 1 0-K/A
Amendment No. 1

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)
[x] ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended December 31, 2003
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

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 of Incorporation)	(I.R.S. Employer Identification No.)

1000 Kensington Tower 7130 South Lewis Tulsa, Oklahoma	74136
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code (918) 493-7700

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	New York Stock Exchange

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in PART III of this Form 10-K or any amendment to this Form 10-K. ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes _X_ No ___

Aggregate Market Value of the Voting Stock Held By
Non-affiliates on June 30, 2003 - $669,121,359

Number of Shares of Common Stock
Outstanding on March 11, 2004 - 45,709,568

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 5, 2004 are incorporated by reference in Part III.

Exhibit Index - See Page 113

Form 10-K/A
Amendment No. 1

Explanatory Note

This Amendment No. 1 on Form 10-K/A to Unit Corporation's Annual Report on Form 10-K for the year ended December 31, 2003 is being filed solely to correct a typographical error contained in Item 8, Financial Statements and Supplementary Data, Note 13. Total proved developed natural gas reserves are 182,853 MMcf rather than 128,853 MMcf as originally filed. This Amendment also includes updated Exhibits 31.1 and 31.2 as contemplated by Rule 12b-15 promulgated under the Securities Exchange Act of 1934, as amended. In all other respects, the text of this Amendment remains unchanged from the previously filed Annual Report on Form 10-K.

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

UNIT CORPORATION
(Registrant)

By: /s/ David T. Merrill

David T. Merrill
Chief Financial Officer and
Treasurer

Date: March 17, 2004

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2002	2003
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 497	$ 598
Accounts receivable (less allowance for doubtful accounts of $1,203 and $1,223)	33,912	58,807
Materials and supplies	8,794	8,023
Income tax receivable	3,602	112
Prepaid expenses and other	4,594	5,202
Total current assets	51,399	72,742
Property and Equipment:		
Drilling equipment	369,777	424,321
Oil and natural gas properties, on the full cost method:		
Proved Properties	449,226	528,110
Undeveloped Leasehold not being amortized	16,024	17,486
Transportation equipment	6,856	9,828
Other	9,906	14,535
	851,789	994,280
Less accumulated depreciation, depletion, amortization and impairment	341,031	385,219
Net property and equipment	510,758	609,061
Goodwill	12,794	23,722

Other Assets	3,212	7,400
Total Assets	$ 578,163	$ 712,925

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

	As of December 31,	
	2002	2003
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities (Note 4)	$ 1,465	$ 1,015
Accounts payable	21,119	32,871
Accrued liabilities	11,921	15,921
Contract advances	27	2,004
Total current liabilities	34,532	51,811
Long-Term Debt (Note 4)	30,500	400
Other Long-Term Liabilities (Note 4)	5,439	17,893
Deferred Income Taxes (Note 5)	86,320	127,053
Commitments and Contingencies (Note 9)		
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, 43,339,400 and 45,592,012 shares issued, respectively	8,668	9,117
Capital in excess of par value	264,180	307,938
Retained earnings	148,524	198,713
Total shareholders' equity	421,372	515,768
Total Liabilities and Shareholders' Equity	$ 578,163	$ 712,925

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2001	2002	2003
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 167,042	$ 118,173	$ 183,146
Oil and natural gas	90,237	67,959	116,609
Other	1,900	1,504	2,829
Total revenues	259,179	187,636	302,584
Expenses:			

Contract drilling:			
Operating costs	91,006	91,338	138,762
Depreciation	13,888	14,684	23,644
Oil and natural gas:			
Operating costs	22,196	20,795	25,169
Depreciation, depletion, amortization and impairment	22,116	23,338	27,343
General and administrative	8,476	8,712	9,222
Interest	2,818	973	693
Total expenses	160,500	159,840	224,833
Income Before Income Taxes and Change in Accounting Principle	98,679	27,796	77,751
Income Tax Expense:			
Current	5,609	(3,469)	--
Deferred	30,304	13,021	28,887
Total income taxes	35,913	9,552	28,887
Income Before Change in Accounting Principle	62,766	18,244	48,864
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811)	--	--	1,325
Net Income	$ 62,766	$ 18,244	$ 50,189

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

	Year Ended December 31,		
	2001	2002	2003
	(In thousands except per share amounts)		
Basic Earnings Per Common Share:			
Income before change in accounting principle	$ 1.75	$ 0.47	$ 1.12
Cumulative effect of change in accounting principle net of income tax	--	--	0.03
Net income	$ 1.75	$ 0.47	$ 1.15
Diluted Earnings Per Common Share:			
Income before change in accounting principle	$ 1.73	$ 0.47	$ 1.12
Cumulative effect of change in accounting principle net of income tax	--	--	0.03
Net income	$ 1.73	$ 0.47	$ 1.15
Pro Forma Amounts Assuming Retroactive Application of Change in Accounting Principle:			

Net income	$ 62,662	$ 18,115
Basic earnings per share	$ 1.74	$ 0.47
Diluted earnings per share	$ 1.73	$ 0.46

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2001	$ 7,154	$ 139,872	$ 67,514	$ --	$ --	$ 214,540
Net Income	--	--	62,766	--	--	62,766
Activity in employee compensation plans (237,923 shares)	47	2,105	--	--	--	2,152
Purchase of treasury shares (30,000 shares)	--	--	--	--	(296)	(296)
Other comprehensive income (net of tax of $771 and $771):						
Change in value of cash flow derivative instruments used as cash flow hedges	--	--	--	1,258	--	1,258
Adjustment reclassification - derivative settlements	--	--	--	(1,258)	--	(1,258)
Balances, December 31, 2001	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,162

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY - CONTINUED
Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2002	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,162
Net Income	--	--	18,244	--	--	18,244
Activity in employee compensation plans (113,133 shares)	23	1,156	--	--	296	1,475
Issuance of stock for acquisition (7,220,000 shares)	1,444	121,047	--	--	--	122,491
Other comprehensive income (net of tax of $15 and $15):						
Change in value of cash flow derivative instruments used as cash flow hedges	--	--	--	25	--	25
Adjustment reclassification - derivative settlements	--	--	--	(25)	--	(25)
Balances, December 31, 2002	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,372

Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2003	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,372
Net Income	--	--	50,189	--	--	50,189
Activity in employee compensation plans (252,612 shares)	49	2,018	--	--	--	2,067
Issuance of 2,000,000 shares of common stock)	400	41,740	--	--	--	42,140
Other comprehensive income (net of tax of $3 and $3):						
Change in value of cash flow derivative instruments used as cash flow hedges	--	--	--	(4)	--	(4)
Adjustment reclassification - derivative settlements	--	--	--	4	--	4
Balances, December 31, 2003	$ 9,117	$ 307,938	$198,713	$ --	$ --	$ 515,768

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2001	2002	2003
	(In thousands)		

Cash Flows From Operating Activities:			
Net Income	$ 62,766	$ 18,244	$ 50,189
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	36,642	38,657	51,783
Equity in net earnings of unconsolidated investments	(1,148)	(745)	(1,516)
Loss (gain) on disposition of assets	(56)	(69)	51
Employee stock compensation plans	2,873	1,165	1,415
Bad debt expense	--	603	645
Plugging liability - cumulative effect - net of accretion	--	--	(1,624)
Deferred tax expense	30,304	13,021	28,887
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	6,334	(43)	(25,540)
Materials and supplies	(1,556)	(3,436)	771
Prepaid expenses and other	(3,533)	2,365	4,240
Accounts payable	(155)	1,784	6,148
Accrued liabilities	929	(350)	4,286
Contract advances	61	(213)	1,977
Other liabilities	(440)	(436)	--
Net cash provided by operating activities	133,021	70,547	121,712

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS - CONTINUED

	Year Ended December 31,		
	2001	2002	2003
		(In thousands)	
Cash Flows From Investing Activities:			
Capital expenditures (including producing property and contract drilling acquisitions)	$(108,339)	$ (75,225)	$(131,162)
Proceeds from disposition of property and equipment	2,631	1,949	1,625
(Acquisition) disposition of other assets	17	540	(2,562)
Net cash used in investing activities	(105,691)	(72,736)	(132,099)
Cash Flows From Financing Activities:			
Borrowings under line of credit	57,200	36,700	65,200
Payments under line of credit	(79,200)	(36,200)	(95,300)
Net payments on notes payable and other long-term debt	(1,000)	(1,161)	(1,105)
Proceeds from exercise of			

stock options	609	413	452
Proceeds from sale of common stock	--	--	42,140
Book overdrafts (Note 1)	(4,978)	2,543	(899)
Acquisition of treasury stock	(296)	--	--
Net cash provided by (used in) financing activities	(27,665)	2,295	10,488
Net Increase (Decrease) in Cash and Cash Equivalents	(335)	106	101
Cash and Cash Equivalents, Beginning of Year	726	391	497
Cash and Cash Equivalents, End of Year	$ 391	$ 497	$ 598
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Interest	$ 2,807	$ 1,053	$ 660
Income taxes	$ 7,779	$ (4,585)	$ (3,495)

See Note 2 for non-cash investing activities.

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its directly and indirectly wholly owned subsidiaries ("Unit"). The investment in limited partnerships is accounted for on the proportionate consolidation method, whereby Unit's share of the partnerships' assets, liabilities, revenues and expenses is included in the appropriate classification in the accompanying consolidated financial statements.

Nature of Business. Unit is engaged in the land contract drilling of natural gas and oil wells and the exploration, development, acquisition and production of oil and natural gas properties. Unit's current contract drilling operations are focused primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and the Rocky Mountain regions. Unit's primary exploration and production operations are also conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of its contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2003, Unit had an interest in a total of 3,393 wells and served as operator of 753 of those wells. Unit provides land contract drilling services for a wide range of customers using the drilling rigs, which it owns and operates. In 2003, 84 of Unit's 88 rigs performed contract drilling services.

Drilling Contracts. Unit recognizes revenues and expenses generated from "daywork" drilling contracts as the services are performed, since the Company does not bear the risk of completion of the well. Under "footage" and "turnkey" contracts, Unit bears the risk of completion of the well therefore, 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 duration of all three types of contracts range typically from 20 to 90 days, but some of our daywork contracts in the Rocky Mountains can range up to one year. The entire amount of a loss, if any, is recorded when the loss is determinable. 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.

Cash Equivalents and Book Overdrafts. Unit includes as cash equivalents, certificates of deposits and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued prior to the end of the period, but not presented to Unit's bank for payment prior to the end of the period. At December 31, 2002 and 2003, book overdrafts of $3.6 million and $2.7 million have been included in accounts payable.

Property and Equipment. Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives, including a minimum provision of 20% of the active rate when the equipment is idle. Unit uses the composite method of depreciation for drill pipe and collars and calculates the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that 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 Unit to reduce the carrying value of property and equipment.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

Goodwill. Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company and SerDrilco Incorporated over the fair value of the net assets acquired. Prior to January 1, 2002 goodwill was amortized on the straight-line method using a 25 year life. Unit expensed $243,000 annually for the amortization of goodwill. On July 20, 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("FAS 142"). For goodwill and intangible assets 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 decreased. FAS 142 became effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Goodwill is all related to the drilling segment. The 2002 increase in the carrying amount of goodwill of $7,706,000 came from the goodwill acquired in the acquisition of CREC Rig Equipment Company and CDC Drilling Company and the 2003 increase in the carrying amount of goodwill of $10,928,000 came from the goodwill acquired in the acquisition of SerDrilco Incorporated. Both acquisitions are more fully discussed in Note 2. Goodwill of $7,009,000 is expected to be deductible for tax purposes. The following table shows the adjusted net income and earnings per share resulting from the removal of the amortization expense (net of income tax) recognized in the prior periods:

	2001	2002	2003
	(In thousands except per share amounts)		

Adjusted Net Income:			
Reported net income	$ 62,766	$ 18,244	$ 50,189
Add back: goodwill amortized - net of income tax	88	--	--
Adjusted net income	$ 62,854	$ 18,244	$ 50,189
Basic Earnings per Share:			
Reported net income	$ 1.75	$ 0.47	$ 1.15
Add back: goodwill amortized - net of income tax	--	--	--
Adjusted net income	$ 1.75	$ 0.47	$ 1.15
Diluted Earnings per Share:			
Reported net income	$ 1.73	$ 0.47	$ 1.15
Add back: goodwill amortized - net of income tax	--	--	--
Adjusted net income	$ 1.73	$ 0.47	$ 1.15

Oil and Natural Gas Operations. Unit accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Unit capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities. Independent petroleum engineers annually review Unit's determination of its oil and natural gas reserves. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $0.91, $1.04 and $1.14 per Mcfe in 2001, 2002 and 2003, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Unit's unproved properties totaling $17.5 million are excluded from the DD&A calculation. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. The full cost ceiling is based principally on the estimated future discounted net cash flows from Unit's oil and natural gas properties. As discussed in Note 13, such estimates are imprecise.

No gains or losses are recognized on the sale, conveyance or other disposition of oil and natural gas properties unless a significant reserve amount is involved.

Unit's contract drilling subsidiary provides drilling services for its exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. During 2003, the contract drilling subsidiary drilled 43 wells for our exploration and production subsidiary. As required by the Securities and Exchange Commission, the profit received by our contract drilling segment of $2,259,000, $841,000 and $1,883,000 during 2001, 2002 and 2003, 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.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in 10 oil and natural gas limited partnerships sold privately and publicly. Some of Unit's officers, directors and employees own the interests in most of these partnerships. Unit shares partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse Unit for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

Natural Gas Balancing. Unit uses 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. Unit estimates its December 31, 2003 balancing position to be approximately 1.8 Bcf on under-produced properties and approximately 2.3 Bcf on over-produced properties. Unit has recorded a receivable of $562,000 on certain wells where we estimated that insufficient reserves are available for Unit to recover the under-production from future production volumes. Unit has also recorded a liability of $1,191,000 on certain properties where we believe there is insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Unit's policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which Unit has imbalances are not material.

Investments. Unit owns a 40% equity interest in Superior Pipeline Company LLC, a natural gas gathering and processing company. The investment, including Unit's share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets.

Unit also owns a 16.7% interest carried at cost 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.

Employee and Director Stock Based Compensation. Unit's stock-based compensation plans, which are explained more fully in Note 6, are accounted for under the recognition and measurement principles of APB Opinion 25 "Accounting for Stock Issued to Employees," and related interpretations. Under this standard, no compensation expense is recognized for grants of options, which include an exercise price equal to or greater than the market price of the stock on the date of grant. Accordingly, based on Unit's grants in 2001, 2002 and 2003 no compensation expense has been recognized. Compensation expense included in reported net income is Unit's matching 401(k) contribution which was made in Unit common stock. The following table illustrates the effect on net income and earnings per share if Unit had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	2001	2002	2003
Net Income, as Reported (In Thousands)	$ 62,766	$ 18,244	$ 50,189
Add Stock Based Employee Compensation Expense Included in Reported Net Income - Net of Tax	671	669	858
Less Total Stock Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(1,615)	(1,488)	(2,114)
Pro Forma Net Income	$ 61,822	$ 17,425	$ 48,933
Basic Earnings per Share:			
As reported	$ 1.75	$ 0.47	$ 1.15
Pro forma	$ 1.72	$ 0.45	$ 1.12
Diluted Earnings per Share:			
As reported	$ 1.73	$ 0.47	$ 1.15
Pro forma	$ 1.71	$ 0.45	$ 1.12

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 2001, 2002 and 2003 was 0.55, 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 5.41% in 2001 and

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. The aggregate fair value of options granted during 2002 and 2003 under the Stock Option Plan were $1,669,000 and $1,617,000, respectively. No options were issued under the Stock Option Plan in 2001. Under the Non-Employee Directors' Stock Option Plan the aggregate fair value of options granted during 2001 was $201,000 and $262,000 in 2002 and 2003.

Self Insurance. Unit utilizes self insurance programs for employee group health and worker's compensation. Self insurance costs are accrued based upon the aggregate of estimated liabilities for reported claims and claims incurred but not yet reported. Accrued liabilities include $3,632,000 and $7,990,000 for employer group health insurance and worker's compensation at December 31, 2002 and 2003, respectively. Unit's exposure (i.e. deductible or retention) per occurrence ranged from $200,000 for general liability to $1 million for rig physical damage. Unit has purchased stop-loss coverage

in order to limit, to the extent feasible, its per occurrence and aggregate exposure to certain claims. Following the acquisition of SerDrilco, Unit continued to use SerDrilco's ERISA governed occupational injury benefit plan to cover the SerDrilco employees in lieu of covering them under an insured Texas workers' compensation plan.

Treasury Stock. On August 30, 2001, Unit's Board of Directors authorized the purchase of up to one million shares of Unit's common stock. The timing of stock purchases are made at the discretion of management. During 2001, 30,000 shares were repurchased for $296,000. These shares were used for a portion of the company match to the 401(k) Employee Thrift Plan. No treasury stock was owned by Unit at December 31, 2002 and 2003.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject Unit to concentrations of credit risk, consist primarily of trade receivables with a variety of national and international oil and natural gas companies. Unit does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large number of customers comprising Unit's customer base. During 2003, Chesapeake Operating, Inc. was our largest drilling customer and provided 15% of our total contract drilling revenues. Purchases by Cinergy Marketing & Trading LP accounted for approximately 17% of Unit's oil and natural gas revenues in 2003 while purchases by Centerpoint Energy Gas accounted for approximately 16% of Unit's oil and natural gas revenues. Unit owns a 16.7% in Eagle Energy Partners I LP, whose purchases accounted for 6% of Unit's oil and natural gas revenues in 2003. In addition, at December 31, 2002 and 2003, Unit had a concentration of cash of $3.0 million and $3.5 million, respectively, with one bank.

Hedging Activities. On January 1, 2001, Unit adopted Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No.'s 137 and 138), "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). This statement requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, Unit is required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

Unit periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists. Initial adoption of this standard was not material.

Unit entered into a collar contract for approximately 25% of its daily production for January and February of 2001. The collar had a floor of $26.00 and a ceiling of $33.00 and Unit received $0.86 per barrel for entering into the collar transaction. During the first quarter of 2001, the net effect of this hedging transaction yielded an increase in oil revenues of $17,200.

During the second quarter of 2001, Unit entered into a natural gas collar contract for approximately 36% of its June and July 2001 natural gas production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, Unit entered into two natural gas collar contracts for approximately 38% of its September through November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. During 2001 natural gas collar contracts added $2,030,000 to Unit's natural gas revenues.

On April 30, 2002, Unit entered into a collar contract covering approximately 19% of its natural gas production for the periods of April 1, 2002 through October 31, 2002. The collar had a floor of $3.00 and a ceiling of $3.98. During the year of 2002, the natural gas hedging transactions increased natural gas revenues by $40,300. At December 31, 2002, Unit was not holding any natural gas or oil derivative contracts.

During the first quarter of 2003, Unit entered into two collar contracts covering approximately 40% of its natural gas production for the periods of April 1, 2003 through September 30, 2003. One collar had a floor of $4.00 and a ceiling of $5.75 and the other collar had a floor of $4.50 and a ceiling of $6.02. Unit also entered into two collar contracts covering approximately 25% of its oil production for the periods of May 1, 2003 through December 31, 2003. One collar had a floor of $25.00 and a ceiling of $32.20 and the other collar had a floor of $26.00 and a ceiling of $31.40. During the year 2003, the collar contracts decreased natural gas revenues by $6,000 and oil revenues by $5,000. We did not have any hedging transactions outstanding at December 31, 2003.

Accounting Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Impact of Financial 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 year ending December 31, 2003 relating to the company's retirement obligation for plugging liability:

	Short-Term Plugging Liability	Long-Term Plugging Liability
	(In Thousands)	
Plugging Liability 1/1/03	$ 203	$ 10,632
Accretion of Discount	8	505
Liability Incurred in the Period	--	719
Liability Settled in the Period	(65)	(120)
Liability Sold	(36)	(10)
Reclassification of Liability From Long- to Short-Term	193	(193)
Revision of Estimate	--	158
Plugging Liability 12/31/03	$ 303	$ 11,691

The effect of this change increased net property, plant and equipment by $13.0 million and liabilities, including deferred tax liabilities, by $11.7 million at January 1, 2003 and decreased net income for the year ended December 31, 2003 by $148,000 ($0.00 per share). The financial statements for the year ended December 31, 2002 have not been restated and the cumulative effect of the change of $1.3 million net of tax ($0.03 per share) is shown as a one-time addition to income in the first quarter of 2003.

The following table shows the adjusted net income and earnings per share resulting from the accretion of the discount and change in the depreciation, depletion and amortization (both net of income tax) as if the plugging liability had been recognized in the prior year ended periods:

	2000	2001	2002
	(In thousands except per share amounts)		
Adjusted Net Income:			
Reported net income	$ 34,344	$ 62,766	$ 18,244
Add back:			
Decrease in depreciation, depletion and amortization - net of income tax	80	156	167
Deduct:			
Accretion of discount - net of income tax	(231)	(260)	(296)
Adjusted net income	$ 34,193	$ 62,662	$ 18,115
Basic Earnings per Share:			
Reported net income	$ 0.96	$ 1.75	$ 0.47
Net adjustment to income from change in accounting principle	--	(0.01)	--
Adjusted basic earnings per share	$ 0.96	$ 1.74	$ 0.47
Diluted Earnings per Share:			
Reported net income	$ 0.95	$ 1.73	$ 0.47
Net adjustment to income from change in accounting principle	--	--	(0.01)
Adjusted diluted earnings per share	$ 0.95	$ 1.73	$ 0.46

If FAS 143 had been applied at January 1, 2000 and December 31, 2000, 2001 and 2002, the plugging liability would have been $8.0 million, $8.7 million, $9.7 million and $10.8 million, respectively, assuming the liability was measured using the information, assumptions and interest rates used as of the adoption date of January 1, 2003.

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 Unit 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, did not have an impact on Unit's financial position or results of operations. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, Unit will have to adopt FIN 46, as amended, in the quarter ending March 31, 2004. Unit is still evaluating FIN 46 with regard to these types of entities in which it has an ownership interest, primarily oil and gas partnerships and its equity investment in Superior pipeline. FIN 46 may require full consolidation of these entities which would increase total assets with an offsetting minority interest for the percentage not owned by Unit. There will be no net impact to results of operations from the adoption of FIN 46.

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 Unit 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 Unit's financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, Unit, 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.

Unit'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 December 31, 2002 and 2003, Unit had undeveloped leaseholds of approximately $13.2 million and $14.8 million, respectively that would be classified on its balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $18.1 million and $24.6 million, respectively that would be classified as "intangible developed leasehold" if the interpretations were applied. This classification would require Unit to make the disclosures set forth under FAS 142 related to these interests.

Unit intends to continue to classify its oil and gas mineral extraction rights as tangible oil and gas properties until further guidance is provided.

NOTE 2 - ACQUISITIONS

On December 8, 2003, Unit 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 equipment yard in and near Borger, Texas. The results of operations for the acquired entity are included in the statement of operations for the period beginning December 8, 2003 and continuing through December 31, 2003.

Total consideration given in the acquisition was determined based on the depth capacity of the rigs, the working condition of the rigs and the ability of the rigs to enhance Unit's ability to provide services and equipment required by our customers on a timely basis within the Anadarko Basin of Western Oklahoma and the Texas Panhandle. Unit acquired SerDrilco Incorporated's tax basis in the property acquired, so a deferred tax liability and goodwill of $10.9 million was recognized in the recording of the acquisition. The allocation of the total consideration paid and goodwill recognized for the acquisition is as follows (in thousands):

Allocation of Total Consideration Paid and Goodwill Recognized:

Drilling rigs including tubulars	$ 31,012
Spare drilling equipment	904
Office, yard & yard equipment	1,200
Trucking fleet	1,486
Other vehicles	398
Total cash consideration	35,000
Goodwill recognized	10,928
Total consideration paid and recognized	$ 45,928

On August 15, 2002, Unit completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company ("Cactus Acquisition"). 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 Equipment 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 20 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 Statement of Cash Flows. The results of operations for the acquired entities are included in the statement of operations for the period beginning August 15, 2002 and continuing through December 31, 2003.

Total consideration given in both the acquisitions was determined based on the equipment purchased, depth capacity of the rigs, the working condition of the rigs and the ability of the rigs to enhance Unit's ability to provide services and equipment required by our customers on a timely basis within the Anadarko and Gulf Coast areas where the rigs are located. 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
Deferred tax asset	2,155
Goodwill	7,706
Total consideration	$ 126,991

Unaudited summary pro forma results of operations for Unit, reflecting the Cactus Acquisition as if it had occurred at the beginning of the year ended December 31, 2001 are as follow:

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(In thousands except per Per share amounts)	
Revenues	$ 311,104	$ 215,805
Net Income	$ 70,457	$ 15,320

Net Income per Common Share (Diluted)	$ 1.62	$ 0.34

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 3 - EARNINGS PER SHARE

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Year Ended December 31, 2001:			
Basic earnings per common share	$ 62,766	35,967	$ 1.75
Effect of dilutive stock options		291	
Diluted earnings per common share	$ 62,766	36,258	$ 1.73
For the Year Ended December 31, 2002:			
Basic earnings per common share	$ 18,244	38,844	$ 0.47
Effect of dilutive stock options		268	
Diluted earnings per common share	$ 18,244	39,112	$ 0.47

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except)		

		(In thousands, except per share amounts)	
For the Year Ended December 31, 2003:			
Basic earnings per common share:			
Income before change in accounting principle	$ 48,864	43,616	$ 1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,616	0.03
Net Income	$ 50,189	43,616	$ 1.15
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		43,616	
Effect of dilutive stock options		157	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,773	
Income before change in accounting principle	$ 48,864	43,773	$ 1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,773	0.03
Net Income	$ 50,189	43,773	$ 1.15

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

	2001	2002	2003
Options	153,000	198,500	137,850
Average Exercise Price	$ 16.79	$ 19.01	$ 22.52

NOTE 4 - LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-term debt consisted of the following as of December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Revolving Credit and Term Loan, with Interest at December 31, 2002 and 2003 of 2.5% and 4.0%, Respectively	$ 30,500	$ 400
Notes Payable for Hickman Drilling Company Acquisition with Interest at December 31, 2002 of 4.25%	1,000	--
	31,500	400

Less Current Portion	1,000	--
Total Long-Term Debt	$ 30,500	$ 400

At December 31, 2003, Unit had a $100 million bank loan agreement consisting of a revolving credit facility through May 1, 2005 and a term loan thereafter, maturing on May 1, 2008. On January 30, 2004, in conjunction with Unit's acquisition of PetroCorp Incorporated, Unit 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 Unit's assets under the latest loan value computation supported a full $150 million, Unit elected to set the loan commitment at

$120 million in order to reduce financing costs. Unit pays a commitment fee of ..375 of 1% for any unused portion of the commitment amount. Unit 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 Unit's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of Unit's drilling rig fleet, limited to $20 million, is added to the borrowing base. Provisions are also in the agreement which allow for one requested special re-determination of the borrowing base by either the lender or Unit between each scheduled re-determination date if conditions warrant such a request.

At Unit's election, any portion of the debt outstanding may be fixed at a Eurodollar Rate for 30, 60, 90 or 180 day terms. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid upon 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% tp 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 very 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 Unit's banks.

The loan agreement also requires that 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.

Other long-term liabilities consisted of the following as of December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Separation Benefit Plan	$ 2,081	$ 2,545
Deferred Compensation Plan	1,391	1,829

Retirement Agreement	1,412	1,349
Gas Balancing Liability	1,020	1,191
Plugging Liability	--	11,994
	5,904	18,908
Less Current Portion	465	1,015
Total Other Long-Term Liabilities	$ 5,439	$ 17,893

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities from 2004 through 2008 are $1,015,000, $606,000, $686,000, $841,000 and $679,000. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2003 approximates its fair value.

NOTE 5 - INCOME TAXES

A reconciliation of the income tax expense, computed by applying the federal statutory rate to pre-tax income to Unit's effective income tax expense is as follows:

	2001	2002	2003
		(In thousands)	
Income Tax Expense Computed by Applying the Statutory Rate	$ 34,538	$ 9,739	$ 27,213
State Income Tax, Net of Federal Benefit	2,859	834	2,333
Statutory Depletion and Other	(1,484)	(1,021)	(659)
Income tax expense	$ 35,913	$ 9,552	$ 28,887

Deferred tax assets and liabilities are comprised of the following at December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Deferred Tax Assets:		
Allowance for losses and nondeductible accruals	$ 3,942	$ 9,972
Net operating loss carryforward	17,752	20,745
Statutory depletion carryforward	4,231	4,476
Alternative minimum tax credit carryforward	395	395
Gross deferred tax assets	26,320	35,588
Deferred Tax Liability:		
Depreciation, depletion and amortization	(110,598)	(159,990)
Net deferred tax liability	(84,278)	(124,402)
Current Deferred Tax Asset	2,042	2,651
Non-Current - Deferred Tax Liability	$ (86,320)	$ (127,053)

Realization of the deferred tax asset is dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced.

At December 31, 2003, Unit has an excess statutory depletion carryforward of approximately $11,778,000, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations. At December 31, 2003, Unit has net operating loss carryforwards of approximately $54,591,000 which expire from 2019 to 2022.

NOTE 6 - EMPLOYEE BENEFIT AND COMPENSATION PLANS

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan ("the Plan") whereby 330,950 shares of common stock were authorized for issuance under the Plan. On May 3, 1995, Unit's shareholders approved and amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the Plan. Under the terms of the Plan, bonuses may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in annual installments subject to certain restrictions. No shares were issued under the Plan in 2001, 2002 and 2003.

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

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2001	719,700	$ 6.87
Exercised	(177,200)	3.13
Cancelled	(10,400)	10.26
Outstanding at December 31, 2001	532,100	8.09
Granted	160,000	19.03
Exercised	(59,400)	5.67
Outstanding at December 31, 2002	632,700	11.08
Granted	116,850	22.89
Exercised	(202,900)	5.94
Cancelled	(9,900)	15.41
Outstanding at December 31, 2003	536,750	$ 15.52

	Outstanding Options at December 31, 2003		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price

$ 3.00 - $ 4.00	99,600	3.8 years	$ 3.52
$ 7.25 - $10.00	45,700	3.2 years	$ 8.52
$11.31 - $14.06	3,500	5.8 years	$ 13.28
$16.69 - $22.95	387,950	8.6 years	$ 19.44

Exercise Prices	Exercisable Options At December 31, 2003 Number of Shares	Weighted Average Exercise Price
$ 2.75 - $ 4.00	99,600	$ 3.52
$ 7.25 - $10.00	45,700	$ 8.52
$11.31 - $14.06	2,500	$ 12.96
$16.69 - $19.04	108,500	$ 17.49

Options for 329,300, 355,100 and 256,300 shares were exercisable with weighted average exercise prices of $6.25, $7.28 and $5.32 at December 31, 2001, 2002 and 2003, respectively.

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

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2001	95,000	$ 7.03
Granted	17,500	17.54
Exercised	(37,000)	6.80
Outstanding at December 31, 2001	75,500	9.58
Granted	21,000	20.10
Exercised	(2,500)	1.75
Outstanding at December 31, 2002	94,000	12.14
Granted	21,000	20.46
Exercised	(34,500)	7.73

Outstanding at December 31, 2003	80,500	$ 8.94

	Outstanding and Exercisable Options at December 31, 2003		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$ 2.88 - $ 3.75	2,500	0.4 years	$ 2.88
$ 6.87 - $ 9.00	15,000	3.8 years	$ 7.58
$12.19 - $17.54	21,000	7.0 years	$ 15.76
$20.10 - $20.46	42,000	8.8 years	$ 20.28

Under Unit's 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. Unit may match each employee's contribution, up to a specified maximum, in full or on a partial basis. Unit made discretionary contributions under the plan of 35,016, 87,452 and 61,175 shares of common stock and recognized expense of $1,082,000, $1,079,000 and $1,365,000 in 2001, 2002 and 2003, respectively.

Unit provides a salary deferral plan ("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. Funds set aside in a trust to satisfy Unit's obligation under the Deferral Plan at December 31, 2001, 2002 and 2003 totaled $1,277,000, $1,391,000 and $1,829,000, respectively. Unit recognizes payroll expense and records a liability at the time of deferral.

Effective January 1, 1997, Unit adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with Unit 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 Unit in exchange for receiving the separation benefits. On October 28, 1997, Unit 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. Unit recognized expense of $589,000, $619,000 and $707,000 in 2001, 2002 and 2003, respectively, for benefits associated with anticipated payments from both separation plans.

Unit has entered into key employee change of control contracts with six of its current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year upon each anniversary, unless a notice not to extend is given by Unit. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated (other than for cause, death or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and upon certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary

plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 7 - TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 10 oil and gas limited partnerships. Four were formed for investment by third parties and six (the employee partnerships) were formed to allow employees of Unit and its subsidiaries and directors of Unit to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984, 1985 and 1986. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount ($22,680 for 2002 and 2003 and $36,000 for 2004) and to the directors of Unit.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships at the end of last year was done by the general partners under the authority contained in the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships have each had a set percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the particular year for which the partnership was formed. The total interest the employees have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

Amounts received in the years ended December 31 from both public and private Partnerships for which Unit is a general partner are as follows:

	2001	2002	2003
		(In thousands)	
Contract Drilling	$ 416	$ 209	$ 428
Well Supervision and Other Fees	$ 498	$ 510	$ 236
General and Administrative Expense Reimbursement	$ 193	$ 210	$ 209

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

A subsidiary of Unit paid the Partnerships, for which Unit or a subsidiary is the general partner, $3,000, $1,000 and $2,000 during the years ended December 31, 2001, 2002 and 2003, respectively, for purchases of natural gas production.

Unit owns a 40% equity interest in Superior Pipeline Company LLC, an Oklahoma Limited Liability Company. Superior is a natural gas gathering and processing company. The investment, including Unit's share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets in Unit's consolidated balance sheet. During 2003, Superior Pipeline Company LLC purchased $3.3 million of our natural gas production and paid $64,000 for our natural gas liquids. We paid this company $39,000 for gathering and compression services.

Unit also owns a 16.7% limited partnership interest in Eagle Energy Partnership I, L.P. ("Eagle"), carried at cost, 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. Total purchases by Eagle Energy Partnership I, L.P., which are competitively marketed, accounted for 6% of Unit's oil and natural gas revenues in 2003. Unit increased its sales to Eagle Energy Partners I LP since it first starting selling natural gas to them in August, 2003. For the period August through December 2003 Eagle has purchased 16% of Unit's oil and natural gas revenues.

NOTE 8 - SHAREHOLDER RIGHTS PLAN

Unit maintains a Shareholder Rights Plan (the "Plan") designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Unit without offering fair value to all shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from Unit one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by Unit or to purchase from an acquiring company certain shares of its common stock or the surviving company's common stock at 50% of its value.

The rights become exercisable 10 days after Unit learns that an acquiring person (as defined in the Plan) has acquired 15% or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15% or more of such shares. Unit can redeem the rights for $0.01 per right at any date prior to the earlier of (i) the close of business on the 10th day following the time Unit learns that a person has become an acquiring person or (ii) May 19, 2005 (the "Expiration Date"). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Unit leases office space in Tulsa and Woodward Oklahoma and Houston Texas under the terms of operating leases expiring through January 31, 2010. Future minimum rental payments under the terms of the leases are approximately $719,000, $710,000, $714,000, $531,000 and $423,000 in 2004, 2005, 2006, 2007 and 2008, respectively. Total rent expense incurred by the Company was $582,000, $678,000 and $752,000 in 2001, 2002 and 2003, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, upon the election of a limited partner, that Unit 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. Unit made repurchases of $1,000 and $106,000 in 2002 and 2003, respectively, for such limited partners' interests. No repurchases were made in 2001. In 2001, Unit paid $15,000 for interests in two of the Questa limited partnerships and subsequently dissolved one of the Questa partnerships.

Unit manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to Unit's satisfaction, or agree to assume liability for the remediation of the property.

We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the rig is on the location and the cost has been included in the direct cost of drilling the well.

Unit is a party to various legal proceedings arising in the ordinary course of its business none of which, in management's opinion, will result in judgments which would have a material adverse effect on Unit's financial position, operating results or cash flows.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

Unit has two business segments: Contract Drilling and Oil and Natural Gas, representing its two main 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.

The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 1). Management evaluates the performance of Unit's 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.

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	2001	2002	2003
		(In thousands)	
Revenues:			
Contract drilling	$ 169,301	$ 119,014	$ 188,832
Elimination of intersegment revenue	2,259	841	5,686
Contract drilling net of intersegment revenue	167,042	118,173	183,146
Oil and natural gas	90,237	67,959	116,609
Other	1,900	1,504	2,829
Total revenues	$ 259,179	$ 187,636	$ 302,584
Operating Income (1):			
Contract drilling	$ 62,148	$ 12,151	$ 20,740
Oil and natural gas	45,925	23,826	64,097
Total operating income	108,073	35,977	84,837
General and administrative expense	(8,476)	(8,712)	(9,222)
Interest expense	(2,818)	(973)	(693)
Other income (expense)- net	1,900	1,504	2,829
Income before income taxes	$ 98,679	$ 27,796	$ 77,751
Identifiable Assets (2):			
Contract drilling	$ 183,471	$ 299,655	$ 364,855
Oil and natural gas	220,476	261,440	327,172
Total identifiable assets	403,947	561,095	692,027
Corporate assets	13,306	17,068	20,898
Total assets	$ 417,253	$ 578,163	$ 712,925

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	2001	2002	2003
		(In thousands)	
Capital Expenditures:			
Contract drilling	$ 51,280	$ 139,298 (3)	$ 71,899 (4)
Oil and natural gas	56,933	58,778	80,883 (5)
Other	539	516	3,940
Total capital expenditures	$ 108,752	$ 198,592	$ 156,722
Depreciation, Depletion, Amortization and Impairment:			
Contract drilling	$ 13,888	$ 14,684	$ 23,644
Oil and natural gas	22,116	23,338	27,343
Other	638	635	796
Total depreciation, depletion, amortization and impairment	$ 36,642	$ 38,657	$ 51,783

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(1) Operating income is total operating revenues less operating expenses,

depreciation, depletion, amortization and impairment and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

(2) Identifiable assets are those used in Unit's operations in each industry segment. Corporate assets are principally cash and cash equivalents, short-term investments, corporate leasehold improvements, furniture and equipment.

(3) Includes $7.7 million for goodwill and $2.2 million for deferred tax assets.

(4) Includes $10.9 million for goodwill.

(5) Includes $7.6 million for capitalized cost relating to plugging liability recorded in 2003.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2002 and 2003 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year Ended December 31, 2002:				
Revenues	$ 38,730	$ 44,753	$ 48,272	$ 55,881
Gross profit(1)	$ 6,515	$ 10,295	$ 8,107	$ 11,060
Income before income taxes	$ 4,254	$ 8,297	$ 6,022	$ 9,223
Net income(2)	$ 2,642	$ 5,108	$ 3,708	$ 6,786
Earnings per common share:				
Basic (3)	$ 0.07	$ 0.14	$ 0.09	$ 0.16
Diluted (4)	$ 0.07	$ 0.14	$ 0.09	$ 0.16
Year Ended December 31, 2003:				
Revenues	$ 68,446	$ 72,980	$ 78,201	$ 82,957
Gross profit(1)	$ 22,447	$ 20,214	$ 22,251	$ 19,925
Income before income taxes and change in accounting principle	$ 20,418	$ 18,857	$ 20,598	$ 17,878
Income before change in accounting principle	$ 12,659	$ 11,691	$ 12,763	$ 11,751
Net Income(2)	$ 13,984	$ 11,691	$ 12,763	$ 11,751

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Earnings Before Change in Accounting				

Principle per Common Share:				
Basic	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Net Income per Common Share:				
Basic	$ 0.32	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.32	$ 0.27	$ 0.29	$ 0.27

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(1) Gross profit excludes other revenues, general and administrative expense and interest expense.

(2) The net income for the three months ended December 31, 2002 and 2003 includes a tax benefit of $1.1 million and $0.8 million, respectively, relating primarily to an increase in the estimated amount of statutory depletion carryforward.

(3) Due to the effect of rounding basic earnings per share for the year's four quarters does not equal the annual earnings per share.

(4) Due to the effect of price changes of Unit's stock, diluted earnings per share for the year's four quarters, which includes the effect of potential dilutive common shares calculated during each quarter, does not equal the annual diluted earnings per share, which includes the effect of such potential dilutive common shares calculated for the entire year.

NOTE 12 - SUBSEQUENT EVENT
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On January 30, 2004 Unit acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash. PetroCorp Incorporated explored and developed 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 Unit's reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for development drilling in the future. With the acquisition of PetroCorp Incorporated, Unit also entered into a new $150 million credit facility to replace its existing loan agreement as more fully discussed in Note 4.

The preliminary allocation of the total consideration paid for the acquisition is as follows (in thousands):

Working Capital	$ 93,668
Undeveloped Oil and Natural Gas Properties	6,557
Proved Oil and Natural Gas Properties	114,518
Property and Equipment - Other	401
Other Assets	1,499
Other Long-Term Liabilities	(5,557)
Deferred Income Taxes (net)	(28,966)
Total consideration	$ 182,120

Unaudited summary pro forma results of operations for Unit, reflecting the above described acquisition as if it had occurred at the beginning of the year ended December 31, 2002 and December 31, 2003, are as follows, respectively; revenues, $217.0 million and $339.6 million; income from continuing operations of $19.5 million and $55.2 million; net income of $19.5 million and $53.5 million; income from continuing operations per common share (diluted) of $0.50 and $1.26 and net income per common shares (diluted) of $0.50 and $1.22. 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 period nor of the results which may occur in the future.

NOTE 13 - OIL AND NATURAL GAS INFORMATION

The capitalized costs at year end and costs incurred during the year were as follows:

	USA	Canada	Total
		(In thousands)	
2001:			
Capitalized costs:			
Proved properties	$ 391,216	$ 888	$ 392,104
Unproved properties	14,207	180	14,387
	405,423	1,068	406,491
Accumulated depreciation, depletion, amortization and impairment	(196,270)	(475)	(196,745)
Net capitalized costs	$ 209,153	$ 593	$ 209,746
Cost incurred:			
Unproved properties acquired	$ 7,503	$ 21	$ 7,524
Proved properties acquired	1,419	--	1,419
Exploration	9,336	--	9,336
Development	38,359	295	38,654
Total costs incurred	$ 56,617	$ 316	$ 56,933
2002:			
Capitalized costs:			
Proved properties	$ 448,331	$ 895	$ 449,226
Unproved properties	15,692	332	16,024
	464,023	1,227	465,250
Accumulated depreciation, depletion, amortization and impairment	(218,956)	(520)	(219,476)
Net capitalized costs	$ 245,067	$ 707	$ 245,774
Cost incurred:			
Unproved properties acquired	$ 5,330	$ 152	$ 5,482
Proved properties acquired	13,379	--	13,379
Exploration	6,591	--	6,591
Development	33,319	7	33,326
Total costs incurred	$ 58,619	$ 159	$ 58,778

	USA	Canada	Total
		(In thousands)	
2003:			
Capitalized costs:			
Proved properties	$ 527,196	$ 914	$ 528,110
Unproved properties	17,149	337	17,486

	544,345	1,251	545,596
Accumulated depreciation, depletion, amortization and impairment	(240,047)	(540)	(240,587)
Net capitalized costs	$ 304,298	$ 711	$ 305,009
Cost incurred:			
Unproved properties acquired	$ 8,611	$ 19	$ 8,630
Proved properties acquired	2,557	--	2,557
Exploration	7,071	--	7,071
Development(1)	62,620	5	62,625
Total costs incurred	$ 80,859	$ 24	$ 80,883

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(1) Includes $7.0 million of capitalized cost for plugging liability recorded in the first quarter of 2003 for wells drilled in prior years.

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2003, by the year in which such costs were incurred.

	2000 and Prior	2001	2002	2003	Total
	(In thousands)				
Undeveloped Leasehold Acquired	$ 3,341	$ 3,272	$ 3,187	$ 7,686	$ 17,486

The results of operations for producing activities are provided below.

	USA	Canada	Total
	(In thousands)		
2001:			
Revenues	$ 86,810	$ 190	$ 87,000
Production costs	(18,636)	(23)	(18,659)
Depreciation, depletion and amortization	(19,756)	(40)	(19,796)
	48,418	127	48,545
Income tax expense	(17,621)	(40)	(17,661)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 30,797	$ 87	$ 30,884
2002:			
Revenues	$ 64,534	$ 87	$ 64,621
Production costs	(17,300)	(25)	(17,325)
Depreciation, depletion and amortization	(22,685)	(45)	(22,730)
	24,549	17	24,566
Income tax expense	(8,436)	(5)	(8,441)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 16,113	$ 12	$ 16,125
2003:			

Revenues	$ 114,398	$ 171	$ 114,569
Production costs	(21,366)	(21)	(21,387)
Depreciation, depletion and amortization	(27,059)	(20)	(27,079)
	65,973	130	66,103
Income tax expense	(24,508)	(41)	(24,549)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 41,465	$ 89	$ 41,554

Estimated quantities of proved developed oil and natural gas reserves and changes in net quantities of proved developed and undeveloped oil and natural gas reserves were as follows (unaudited):

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
2001:						
Proved developed and undeveloped reserves:						
Beginning of year	4,183	215,196	--	441	4,183	215,637
Revision of previous estimates	(214)	(24,253)	--	(7)	(214)	(24,260)
Extensions, discoveries and other additions	861	54,521	--	--	861	54,521
Purchases of minerals in place	8	1,246	--	--	8	1,246
Sales of minerals in place	(3)	(26)	--	--	(3)	(26)
Production	(492)	(18,819)	--	(45)	(492)	(18,864)
End of Year	4,343	227,865	--	389	4,343	228,254
Proved developed reserves:						
Beginning of year	3,222	162,718	--	389	3,222	163,107
End of year	2,753	150,419	--	338	2,753	150,757
2002:						
Proved developed and undeveloped reserves:						
Beginning of year	4,343	227,865	--	389	4,343	228,254
Revision of previous estimates	(166)	(10,543)	--	(31)	(166)	(10,574)
Extensions, discoveries and other additions	230	29,541	--	--	230	29,541
Purchases of minerals in place	192	16,558	--	--	192	16,558
Sales of minerals in place	(30)	--	--	--	(30)	--
Production	(473)	(18,927)	--	(41)	(473)	(18,968)
End of Year	4,096	244,494	--	317	4,096	244,811
Proved developed reserves:						
Beginning of year	2,753	150,419	--	338	2,753	150,757
End of year	2,951	168,049	--	317	2,951	168,366

USA Canada Total

	Oil Bbls(1)	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
2003:						
Proved developed and undeveloped reserves:						
Beginning of year	4,096	244,494	--	317	4,096	244,811
Revision of previous estimates	629	(10,510)	--	371	629	(10,139)
Extensions, discoveries and other additions	1,000	39,762	--	--	1,000	39,762
Purchases of minerals in place	8	437	--	--	8	437
Sales of minerals in place	(76)	(31)	--	--	(76)	(31)
Production	(516)	(20,610)	--	(38)	(516)	(20,648)
End of Year	5,141	253,542	--	650	5,141	254,192
Proved developed reserves:						
Beginning of year	2,951	168,049	--	317	2,951	168,366
End of year	3,984	182,203	--	650	3,984	182,853

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(1) Oil includes natural gas liquids in barrels.

Oil and natural gas reserves cannot be measured exactly. Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures. Unit utilizes Ryder Scott Company, independent petroleum consultants, to review its reserves as prepared by its reservoir engineers.

Proved oil and gas reserves, as defined in SEC Rule 4-10(a), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

- that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and

- the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data as previously explained. 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. The information set forth herein is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves nor of estimated future cash flows.

The standardized measure of discounted future net cash flows ("SMOG") was calculated using year-end prices and costs, and year-end statutory tax rates, adjusted for permanent differences, that relate to existing proved oil and natural gas reserves. SMOG as of December 31 is as follows (unaudited):

	USA	Canada	Total
	(In thousands)		
2001:			
Future cash flows	$ 676,051	$ 975	$ 677,026
Future production costs	(220,590)	(311)	(220,901)

Future development costs	(58,909)	(30)	(58,939)
Future income tax expenses	(94,037)	(134)	(94,171)
Future net cash flows	302,515	500	303,015
10% annual discount for estimated timing of cash flows	(125,238)	(194)	(125,432)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 177,277	$ 306	$ 177,583
2002:			
Future cash flows	$1,256,434	$ 1,400	$1,257,834
Future production costs	(320,940)	(309)	(321,249)
Future development costs	(65,266)	--	(65,266)
Future income tax expenses	(250,413)	(233)	(250,646)
Future net cash flows	619,815	858	620,673
10% annual discount for estimated timing of cash flows	(275,015)	(344)	(275,359)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 344,800	$ 514	$ 345,314
2003:			
Future cash flows	$1,548,785	$ 3,500	$1,552,285
Future production costs	(418,007)	(581)	(418,588)
Future development costs	(72,891)	--	(72,891)
Future income tax expenses	(313,827)	(805)	(314,632)
Future net cash flows	744,060	2,114	746,174
10% annual discount for estimated timing of cash flows	(325,182)	(738)	(325,920)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 418,878	$ 1,376	$ 420,254

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows (unaudited):

	USA	Canada	Total
		(In thousands)	
2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (68,174)	$ (167)	$ (68,341)
Net changes in prices and production costs	(768,295)	(1,600)	(769,895)
Revisions in quantity estimates and changes in production timing	(32,705)	13	(32,692)
Extensions, discoveries and improved recovery, less related costs	54,127	--	54,127
Changes in estimated future development cost	2,673	--	2,673
Previously estimated cost incurred during the period	7,361	--	7,361
Purchases of minerals in place	1,217	--	1,217
Sales of minerals in place	(220)	--	(220)
Accretion of discount	99,953	205	100,158
Net change in income taxes	271,421	524	271,945
Other - net	(64,668)	(108)	(64,776)
Net change	(497,310)	(1,133)	(498,443)
Beginning of year	674,587	1,439	676,026

	USA	Canada	Total
End of year	$ 177,277	$ 306	$ 177,583
2002:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (47,230)	$ (62)	$ (47,292)
Net changes in prices and production costs	230,934	363	231,297
Revisions in quantity estimates and changes in production timing	(49,000)	(110)	(49,110)
Extensions, discoveries and improved recovery, less related costs	60,957	--	60,957
Changes in estimated future development cost	1,743	--	1,743
Previously estimated cost incurred during the period	9,911	30	9,941
Purchases of minerals in place	23,334	--	23,334
Sales of minerals in place	(150)	--	(150)
Accretion of discount	23,080	39	23,119
Net change in income taxes	(84,843)	(59)	(84,902)
Other - net	(1,213)	7	(1,206)
Net change	167,523	208	167,731
Beginning of year	177,277	306	177,583
End of year	$ 344,800	$ 514	$ 345,314

	USA	Canada	Total
		(In thousands)	
2003:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (93,948)	$ (150)	$ (94,098)
Net changes in prices and production costs	65,611	195	65,806
Revisions in quantity estimates and changes in production timing	(14,637)	1,007	(13,630)
Extensions, discoveries and improved recovery, less related costs	113,421	--	113,421
Changes in estimated future development cost	(5,356)	--	(5,356)
Previously estimated cost incurred during the period	15,664	--	15,664
Purchases of minerals in place	881	--	881
Sales of minerals in place	(837)	--	(837)
Accretion of discount	48,317	66	48,383
Net change in income taxes	(38,950)	(386)	(39,336)
Other - net	(16,088)	130	(15,958)
Net change	74,078	862	74,940
Beginning of year	344,800	514	345,314
End of year	$ 418,878	$ 1,376	$ 420,254

Unit's SMOG and changes therein were determined in accordance with Statement of Financial Accounting Standards No. 69. Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. Management believes such information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect management's expectations of actual revenues to be derived from those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of such reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to difficulty inherent in predicting the future, variations from the expected production rate could result from factors outside of management's control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

Future cash flows are computed by applying year-end spot prices of oil $32.52 and natural gas $5.67 relating to proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at the end of the year, based on continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil and natural gas reserves less the tax basis of Unit's properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to Unit's proved oil and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

REPORT OF INDEPENDENT AUDITORS

The Shareholders and Board of Directors
Unit Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, changes in shareholders' equity and cash flows present fairly in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2002 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the requirements of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 18, 2004

Exhibit 31.1

CERTIFICATIONS UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John G. Nikkel, certify that:

1. I have reviewed this annual report on Form 10-K as amended by Amendment No. 1 filed on Form 10-K/A of Unit Corporation;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 annual report (the "Evaluation Date"); and

c) presented in this annual 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 annual 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: March 17, 2004

By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chairman of the Board,
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David T. Merrill, certify that:

1. I have reviewed this annual report on Form 10-K as amended by Amendment No. 1 filed on Form 10-K/A of Unit Corporation;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 annual report (the "Evaluation Date"); and

c) presented in this annual 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 annual 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: March 17, 2004

By: /s/ David T. Merrill

DAVID T. MERRILL
Chief Financial Officer and
Treasurer (Principal Financial
Officer)