F O R M 1 0-K

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
UNIT CORPORATION

TABLE OF CONTENTS

PART I

Item 1.	Business.	2
Item 2.	Properties.	2
Item 3.	Legal Proceedings	26
Item 4.	Submission of Matters to a Vote of Security Holders . .	26

PART II

Item 5.	Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	27
Item 6.	Selected Financial Data	28
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	29
Item 7a.	Quantitative and Qualitative Disclosure about Market Risk	47
Item 8.	Financial Statements and Supplementary Data	48
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	104
Item 9a.	Controls and Prodedures	.104

PART III

Item 10.	Directors and Executive Officers of the Registrant. . .	105
Item 11.	Executive Compensation.	105
Item 12.	Security Ownership of Certain Beneficial Owners, Management and Related Shareholder Matters.	105
Item 13.	Certain Relationships and Related Transactions.	105
Item 14.	Principal Accounting Fees and Services.	105

PART IV

Item 15.	Exhibits, Financial Statement Schedules and Reports on Form 8-K	105

Signatures 112

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2003

PART I

Item 1. ***Business* and Item 2. *Properties***

OUR BUSINESS

Through our two principal wholly owned subsidiaries, Unit Drilling Company and Unit Petroleum Company, we

- contract to drill onshore oil and natural gas wells for others and
- explore, develop, acquire and produce oil and natural gas properties for our own account.

We were founded in 1963 as a contract drilling company.

Our executive offices are at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700.

Our primary Internet address is www.unitcorp.com. We make our periodic SEC Reports (Forms 10-Q and Forms 10-K) and current reports (Form 8-K) available free of charge through our Web site as soon as reasonably practicable after they are filed electronically with the SEC. In addition, we post on our Web site copies of the various corporate governance documents that we have adopted. We may from time to time provide important disclosures to investors by posting them in the investor relations section of our Web site, as allowed by SEC rules.

Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet Web site at www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file electronically with the SEC.

When used in this report, the terms Corporation, Company, Unit, our, we and its refer to Unit Corporation and, as appropriate, Unit Corporation and/or one or more of its subsidiaries.

OUR LAND CONTRACT DRILLING BUSINESS

General. Using our 88 drilling rigs, our wholly owned subsidiary, Unit Drilling Company, drills onshore natural gas and oil wells for a wide range of customers. Our drilling operations are mainly in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and in the East Texas and Rocky Mountain regions.

The following table sets forth, for each of the periods indicated, certain information concerning our contract drilling operations:

	Year Ended December 31,				
	1999	2000	2001	2002	2003
Number of Rigs Owned at End of Period	47.0	50.0	55.0	75.0	88.0
Average Number of Rigs Owned During Period	37.3	47.0	51.8	61.6	75.9
Average Number of Rigs Utilized	23.1	39.8	46.3	39.1	62.9
Utilization Rate (1)	62%	85%	90%	63%	83%
Average Revenue Per Day (2)	$6,582	$7,432	$9,879	$8,285	$7,972
Total Footage Drilled (Feet in 1000's)	2,211	3,650	4,008	3,829	6,580
Number of Wells Drilled	197	316	361	318	530

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(1) We determine our utilization rate on a 365 day year by dividing the number of rigs used by our total number of rigs.

(2) Represents total revenues from contract drilling operations divided by the total number of days rigs were used during the period.

Acquisitions. On December 8, 2003, we acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, a U.S. land drilling company located in Borger, Texas 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. SerDrilco, a private, Tulsa-based drilling company, has been operating in the Anadarko Basin in the Texas Panhandle for more than 50 years. Equipment acquired through the SerDrilco acquisition includes 12 rigs which range from 650 horsepower to 1,700 horsepower with depth capacities rated from 6,500 feet to 18,000 feet, a fleet of 12 trucks and a district office and equipment yard in and near Borger, Texas.

During November of 2003, we completed the construction of a 1,500 horsepower diesel electric rig with a depth capacity of 20,000 feet. The rig is operating for our Mid-Continent Division in Western Oklahoma.

Description of our Drilling Rigs. A land drilling rig consists, in part, of engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers and drill pipe. Over the life of a typical rig, due to the normal wear and tear of operating 24 hours a day, several of the major components, such as engines, mud pumps and drill pipe, must be replaced or rebuilt on a periodic basis. Other components, such as the substructure, mast and drawworks, can be used for extended periods of time with proper maintenance. We also own additional equipment used in the operation of our rigs, including large air compressors, trucks and other support equipment.

Our rigs have maximum depth capacities ranging from 9,500 to 40,000 feet.

The following table shows the current distribution of our rigs as of March 1, 2004:

Region	Contracted Rigs	Idle Rigs	Total Rigs	Average Rated Drilling Depths(ft)
Anadarko Basin	59	1	60	16,000
Arkoma Basin	7	--	7	16,000
East Texas and Gulf Coast	13	--	13	18,000
Rocky Mountains	8	--	8	22,000

At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand. As utilization in the industry has improved throughout most of 2003, it has become increasingly difficult to find additional qualified labor for our drilling rigs. More opportunities for field employees to find work in our regions of operation has increased the competition for qualified labor among drilling contractor. If rig utilization remains at its current rate or increases, we expect this competition for qualified labor will continue to have an adverse effect on our drilling operations in the future and result in higher operating costs.

Types of Drilling Contracts We Work Under. Our drilling contracts are predominantly obtained through competitive bidding and are for a single well. Terms and payment rates vary depending on the nature and duration of the work, the equipment and services supplied and other matters. We pay certain operating expenses, including wages of drilling personnel, maintenance expenses and incidental rig supplies and equipment. Usually the contracts are subject to termination by the customer on short notice on payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution. The specific terms of these indemnifications are subject to negotiation on a contract by contract basis.

The type of contract used determines our compensation. The contracts are generally one of three types: daywork; footage; or turnkey. Additional compensation may be acquired for special risks and unusual conditions. Under daywork contracts we provide the drilling rig with the required personnel to the operator who then supervises the drilling of the well. Our compensation depends on a negotiated rate for each day of the rig's use. Footage contracts usually require us to bear some of the drilling costs in addition to providing the rig. We are paid on a negotiated per foot drilled rate on completion of the well. Under turnkey contracts we contract to drill the well for a lump sum amount to a specified depth and provide most of the equipment and services required. We bear the risk of drilling the well to the contract depth and are paid when the contract provisions are completed.

Under turnkey contracts we may incur losses if we underestimate the costs to drill the well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. In 2003, we drilled six turnkey wells and turnkey revenue represented 1% of our contract drilling revenues as compared to 15 turnkey wells and turnkey revenue representing 4% for 2002. We did not have any turnkey contracts in progress at December 31, 2003. Because market conditions as well as the desires of our customers determine the use of turnkey contracts, we can't predict whether the portion of drilling conducted on a turnkey basis will increase or decrease in the future.

Customers. During 2003, 10 customers accounted for approximately 53% of our total contract drilling revenues. Chesapeake Operating, Inc. was our largest customer providing 15% of our total contract drilling revenues. Our contract drilling operations drilled 43 wells in 2003 which were operated by our exploration and production segment. These wells also have working interests which are owned by limited partnerships for which we acted as general partner. As required by the Securities and Exchange Commission, the profit received by our contract drilling segment of $841,000 and $1,883,000 during 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.

Additional Information. Further information relating to contract drilling operations can be found in Notes 1, 2 and 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

OUR OIL AND NATURAL GAS BUSINESS

General. In 1979 we began to develop our exploration and production operations to diversify our contract drilling revenues. Today, our wholly owned subsidiary conducts our exploration and production activities. Our producing oil and natural gas properties, undeveloped leaseholds and related assets are mainly in Oklahoma, Texas, Louisiana and New Mexico and, to a lesser extent, in Arkansas, North Dakota, Colorado, Wyoming, Montana, Alabama, Mississippi, Illinois, Michigan, Nebraska and Canada.

The following table presents certain information regarding the company's oil and gas operations as of December 31, 2003.

Property/Area	Number of Gross Wells	Number of Net Wells	Average Daily Production: Mcf	Average Daily Production: Bbls
Western Division (includes the Rocky Mountain Region, New Mexico, Western and Southern Texas and the Gulf Coast Region)	981	254.44	13,600	880
East Division (consists principally of the Appalachian Region, Arkansas, parts of East Texas and Eastern Oklahoma	553	146.04	17,100	40
Central Division (consist principally of Kansas, the rest of Oklahoma and Texas Panhandle Areas)	1,794	427.91	25,800	480
Canada	65	1.63	100	--
Total	3,393	830.02	56,600	1,400

When we are the operator of a property, we generally employ our own drilling rigs.

Acquisition. On January 30, 2004, we 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 increase our 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 we also entered into a new $150 million credit facility to replace our existing loan agreement as more fully discussed in Note 4 to the Consolidated Financial Statements in Item 8 hereof.

Well and Leasehold Data. The tables below set forth certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,					
	2001		2002		2003	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wells Drilled:						
Exploratory:						
Oil	1	.01	--	--	--	--
Natural gas	8	3.60	2	0.50	3	1.84
Dry	5	4.46	5	2.00	1	1.00
	14	8.07	7	2.50	4	2.84
Development:						
Oil	6	1.06	4	1.91	5	2.13
Natural gas	87	33.51	68	33.25	120	46.22
Dry	18	10.80	17	14.21	20	10.38
	111	45.37	89	49.37	145	58.73
Total	125	53.44	96	51.87	149	61.57

	Year Ended December 31,					
	2001		2002		2003	
	Gross	Net	Gross	Net	Gross	Net
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil - USA	786	279.06	790	273.34	803	280.40
Oil - Canada	--	--	--	--	--	--
Gas - USA	2,188	457.38	2,449	524.45	2,525	547.99
Gas - Canada	64	1.60	65	1.63	65	1.63
Total	3,038	738.04	3,304	799.42	3,393	830.02

On March 1, 2004, we were participating in the drilling of 14 gross (7.1 net) wells in the United States.

Cost incurred for development drilling includes $9.7 million, $10.8 million and $20.4 million in 2001, 2002 and 2003, respectively, to develop booked proved undeveloped reserves.

The following table summarizes our oil and natural gas leasehold acreage for each of the years indicated:

	Developed Acreage		**Undeveloped Acreage**	
	Gross	**Net**	**Gross**	**Net**
2001:				
USA	567,731	155,890	110,489	69,229
Canada	39,040	976	7,273	3,636
Total	606,771	156,866	117,762	72,865
2002:				
USA	585,313	166,397	142,764	79,911
Canada	39,040	976	5,441	3,360
Total	624,353	167,373	148,205	83,271
2003(1):				
USA	600,872	173,674	159,663	90,862
Canada	39,040	976	4,162	2,624
Total	639,912	174,650	163,825	93,486

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(1) Approximately 80% of the net undeveloped acres are covered by leases that will expire in each of the years 2004 - 2006 unless drilling or production otherwise extends the terms of the leases.

Future development costs estimated to be expended to develop our proved undeveloped reserves in the USA in 2004, 2005 and 2006, as disclosed in our December 31, 2003 reserve report, are $33.8 million, $29.3 million and $3.3 million, respectively. No similar future development costs have been estimated for Canada.

Price and Production Data. The following table sets forth our average sales price, oil and natural gas production volumes and average production cost per equivalent Mcf [1 barrel (Bbl) of oil = 6 thousand cubic feet (Mcf) of natural gas] of production for the years indicated:

	Year Ended December 31,		
	2001	**2002**	**2003**
Average Sales Price per Barrel of Oil Produced:			
USA price before hedging	$ 23.58	$ 21.54	$ 26.94
Effect of hedging	0.04	--	--
USA price including hedging	$ 23.62	$ 21.54	$ 26.94
Canada	$ --	$ --	$ --
Average Sales Price per Mcf of Natural Gas Produced:			
USA price before hedging	$ 3.89	$ 2.87	$ 4.87
Effect of hedging	0.11	--	--
USA price including hedging	$ 4.00	$ 2.87	$ 4.87
Canada price before hedging	$ 4.21	$ 2.11	$ 4.49
Effect of hedging	--	--	--
Canada price including hedging	$ 4.21	$ 2.11	$ 4.49
Oil Production (Mbbls):			
USA	492	473	516
Canada	--	--	--
Total	492	473	516
Natural Gas Production (MMcf):			
USA	18,819	18,927	20,610
Canada	45	41	38
Total	18,864	18,968	20,648

Average Production Cost per Equivalent Mcf:			
USA	$ 0.86	$ 0.79	$ 0.90
Canada	$ 0.51	$ 0.60	$ 0.56

Oil and Natural Gas Reserves. The following table sets forth our estimated proved developed and undeveloped oil and natural gas reserves for each of the years indicated:

	Year Ended December 31,		
	2001	**2002**	**2003**
Oil (Mbbls):			
USA	4,343	4,096	5,141
Canada	--	--	--
Total	4,343	4,096	5,141
Natural gas (MMcf):			
USA	227,865	244,494	253,542
Canada	389	317	650
Total	228,254	244,811	254,192

Our oil production is sold at or near our wells under purchase contracts at prevailing prices in accordance with arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms under contracts with terms generally ranging from one month to a year. Most of these contracts contain provisions for readjustment of price, termination and other terms customary in the industry.

Additional Information. Further information relating to oil and natural gas operations can be found in Notes 1, 10, 12 and 13 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil and natural gas reserves as well as the focus of most of the drilling work we do for others, changes in natural gas prices have a larger impact on us than changes in oil prices.

Historically, oil and natural gas prices have been volatile, and we expect them to continue to be so.

The following table shows the highest and lowest average monthly natural gas and oil price we received by quarter for each of the periods indicated:

	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
QUARTER	**High**	**Low**	**High**	**Low**
2001:				
First	$ 9.35	$ 4.82	$ 28.13	$ 26.20
Second	$ 4.92	$ 3.69	$ 26.63	$ 23.78
Third	$ 3.45	$ 2.05	$ 24.66	$ 23.35
Fourth	$ 2.42	$ 2.08	$ 18.99	$ 16.28
2002:				
First	$ 2.11	$ 1.87	$ 19.60	$ 15.58
Second	$ 3.03	$ 2.98	$ 23.44	$ 22.07
Third	$ 2.97	$ 2.47	$ 23.57	$ 23.01
Fourth	$ 3.95	$ 3.35	$ 25.59	$ 21.90
2003:				
First	$ 8.38	$ 4.18	$ 32.72	$ 27.74
Second	$ 5.59	$ 4.22	$ 27.10	$ 24.56
Third	$ 4.63	$ 4.36	$ 27.41	$ 23.62
Fourth	$ 5.06	$ 4.06	$ 27.48	$ 26.31

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;

- United States storage levels of natural gas;
- the ability to transport to key markets;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil and natural gas.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Natural gas prices started to fall in February, 2001. As a result, we started to receive less demand for our drilling rigs starting in October, 2001 and the rates received for our rigs also began to fall until they reached a low of $7,275 per day in February of 2003. As natural gas and oil prices once again began to rise during the last half of 2002 and in the second quarter of 2003 through the remainder of the year both demand for our rigs and dayrates began to improve. In December 2003, the average dayrate of the 76 drilling rigs that we owned prior to the SerDrilco acquisition was approximately $8,200 per day. The 12 rigs added in December 2003 had a dayrate of approximately $7,500 resulting in an average dayrate of $8,130 for all 88 rigs in December 2003. Since short-term and long-term trends in oil and natural gas prices affect the demand for our rigs, future demand and dayrates received for our drilling services is uncertain.

COMPETITION

All of our businesses are highly competitive. Competition in onshore contract drilling traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our competitors in the onshore contract drilling business are substantially larger than we are and have appreciably greater financial and other resources. The competitive environment within which we operate is uncertain and price oriented.

Our oil and natural gas operations likewise encounter strong competition from major oil companies, independent operators and others. Many of these competitors have appreciably greater financial, technical and other resources and have more experience in the exploration for and production of oil and natural gas than we have.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

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.

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 annual 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.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions on such matters as the partnership's participation in a drilling location or a property acquisition, the partnership's expenditure of funds and the distribution of funds to partners. Because the business activities of the limited partners on the one hand and the general partner on the other hand are not the same, conflicts of interest will exist and it is not possible to entirely eliminate such conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In such cases, these drilling operations are under contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate such conflicts.

These partnerships are further described in Notes 1 and 7 to Consolidated Financial Statements set forth in Item 8 hereof.

EMPLOYEES

As of March 1, 2004, we had approximately 1,882 employees in our land contract drilling operations, 70 employees in our oil and natural gas operations and 60 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

OPERATING AND OTHER RISKS

Our drilling operations are subject to the many hazards inherent in the drilling industry, including injury or death to personnel, blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather. Our exploration and production operations are also subject to many of these similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others.

Generally, our drilling contracts provide for the division of responsibilities between us and our customer, and we seek to obtain indemnification from our drilling customers for some of these risks. To the extent that we are unable to transfer these risks to our drilling customers, we seek protection through insurance. However, our insurance or our indemnification agreements, if any, may not adequately protect us against liability from the consequences of the hazards described above. In addition, even if we have insurance coverage, we may still have a degree of exposure based on the amount of our deductible. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses to us. In addition, we may not be able to obtain insurance to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

Exploration and development operations involve numerous risks that may result in dry holes, the failure to produce oil and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing and operating wells is substantial and uncertain. Our operations may be curtailed, delayed or cancelled as a result of many things beyond our control, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or drilling crews and the delivery of equipment.

A majority of the wells in which we own an interest are operated by other parties. As a result, we have little control over the operations of such wells which can act to increase our risk. Operators of these wells may act in ways that are not in our best interests.

Our future performance depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable. In general, production from oil and natural gas properties declines as reserves deplete, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in our oil and natural gas production, revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account. However, it is possible that we may not be able to continue to replace reserves. Low prices of oil and natural gas may also limit the kinds of reserves that we can economically develop. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

GOVERNMENTAL REGULATIONS

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose restrictions on the drilling, production, transportation and sale of oil and natural gas.

Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (the "FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. The FERC's jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. The FERC's jurisdiction over natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, the interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to intrastate commerce.

More recently, the FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market. We do not know what effect the FERC's other activities will have on the access to markets, the fostering of competition and the cost of doing business.

As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counter parties. We believe these changes generally have improved the access to markets for natural gas while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from our properties.

In the past, Congress has been very active in the area of natural gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to "first sales" deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There are other legislative proposals pending in the Federal and State legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products will be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry. We are not able to predict with certainty what effect, if any, these relatively new federal regulations or the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production and related operations. Oklahoma, Texas and other states require permits for drilling operations, drilling bonds and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects its profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

SAFE HARBOR STATEMENT

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

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

- the amount and nature of our future capital expenditures;
- wells to be drilled or reworked;
- prices for oil and gas;
- demand for oil and gas;
- exploitation and exploration prospects;
- estimates of proved oil and gas reserves;
- reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and gas industry;
- business strategy;
- production of oil and gas reserves;
- expansion and growth of our business and operations; and
- drilling rig utilization and drilling rig rates.

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

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

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

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines certain factors that in the future could cause our consolidated results for 2004 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Commodity Prices. The prices we receive for our oil and natural gas production have a direct impact on our revenues, profitability and our cash flow as well as our ability to meet our projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond our control, including the demand for oil and/or natural gas; current weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas; the amount and timing of liquid natural gas imports; and the ability of current distribution systems in the United States to effectively meet the demand for oil and/or natural gas at any given time, particularly in times of peak demand which may result due to adverse weather conditions. Oil prices are extremely sensitive to foreign influences on political, social or economic underpinnings, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets which, at times, has tended to increase the volatility associated with these prices resulting, at times, in large differences in such prices even on a month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2003 production, a $.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow. During 2003, substantially all of our natural gas and crude oil volumes were sold at market responsive prices.

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we sometimes enter into hedging or swap arrangements. Our hedging or swap arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and natural gas prices. These hedging or swap arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices and are more fully discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 hereof.

Drilling Customer Demand. Demand for our drilling services is dependent almost entirely on the needs of third parties. Based on past history, such parties' requirements are subject to a number of factors, independent of any subjective factors, that directly impact the demand for our drilling rigs. These include the availability of funds to such third parties to carry out their drilling operations during any given time period which, in turn, are often subject to downward revision based on decreases in the then current prices of oil and natural gas. Many of our customers are small to mid-size oil and natural gas companies whose drilling budgets tend to be susceptible to the influences of current price fluctuations. Other factors that affect our ability to work our drilling rigs are: the weather which, under adverse circumstances, can delay or even cause the abandonment of a project by an operator; the competition faced by us in securing the award of a drilling contract in a given area; our experience and recognition in a new market area; and the availability of labor to run our drilling rigs.

Uncertainty of Oil and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data included in this document represent only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- the effects of regulations by governmental agencies;
- future oil and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows included in this document is not necessarily the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are determined based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows also are affected by the following factors:

- the amount and timing of production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry in general.

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if we exceed the ceiling, even if prices are depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Debt and Bank Borrowing. We have experienced and expect to continue to experience substantial working capital needs due to the growth in our drilling operations and our active exploration and development programs. Historically, we have funded our working capital needs through a combination of internally generated cash flow, equity financing and borrowings under our bank loan agreement. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2003, our long-term debt outstanding was $400,000. With the acquisition of PetroCorp Incorporated (as further discussed in Note 12 of the Notes to Consolidated Financial Statements) on January 30, 2004, we signed a new loan agreement with a total loan commitment of $150 million, but we elected to limit the amount available for borrowing under our bank loan agreement to $120 million in order to reduce our financing costs. After the PetroCorp acquisition our outstanding debt on February 18, 2004 was $90.0 million.

Our level of debt, the cash flow needed to satisfy our debt and the loan covenants could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than us;
- make us more vulnerable during periods of low oil and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit

facilities.

Our ability to meet our debt service obligations will depend on our future performance. If the requirements of our indebtedness are not satisfied, a default would be deemed to occur and our lenders would be entitled to accelerate the payment of the outstanding indebtedness. If this occurs, we would not have sufficient funds available nor would we be able to obtain the financing required to meet our obligations.

The amount of our existing debt as well as our future debt is, to a large extent, a function of the costs associated with the projects we undertake at any given time and the cash flow we receive. Generally, our normal operating costs are those associated with the drilling of oil and natural gas wells, the acquisition of producing properties, and the costs associated with the maintenance or expansion of our drilling rig fleet. To some extent, these costs, particularly the first two items, are discretionary and we maintain a degree of control regarding the timing and/or the need to incur the same. However, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to acquire a large producing property package or the need to replace a costly rig component due to an unexpected loss, which could force us to incur increased debt above that which we had expected or forecasted. Likewise, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

Executive Officers. The table below and accompanying footnotes set forth certain information concerning each of our executive officers as of March 15, 2004.

NAME	AGE	POSITION HELD
John G. Nikkel	69	Chairman of the Board since August 1, 2003 Director since 1983 Chief Executive Officer since July 1, 2001 President and Chief Operating Officer from 1983 to August 1, 2003
Larry D. Pinkston	49	Director since January 15, 2004 President since August 1, 2003 Chief Operating Officer since February 24, 2004 Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	46	Senior Vice President since December 2002 General Counsel and Corporate Secretary since January 1987
Philip M. Keeley(1)	62	Senior Vice President, Exploration and Production since 1983
David T. Merrill	43	Chief Financial Officer and Treasurer since February 24,2004 Vice President of Finance from August 2003 to February 24,2004

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(1) Mr. Keeley has announced his plans to retire effective April, 15, 2004

Mr. Nikkel joined Unit as its President, Chief Operating Officer and a director in 1983. He was elected its Chief Executive Officer in July, 2001 and Chairman of the Board in August, 2003. He currently holds the position of Chairman of the Board and Chief Executive Officer. From 1976 until January, 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of Cotton from 1979 until his departure. Prior to joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike Exploration Company. From August 16, 2000 until August 23, 2002 Mr. Nikkel, in connection with Unit's investment in the company, also served as a director of Shenandoah Resources Ltd., a Canadian company. Shenandoah Resources Ltd. filed for creditors protection under The Companies' Creditor Arrangement Act in April 2002 with the Court of Queen's Bench of Alberta, Judicial District of Calgary. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Pinkston joined Unit in December, 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President of the company as well as its Chief Financial Officer. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. He was elected as director of the company by the Board in January, 2004. Mr. Pinkston holds the offices of President and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

Mr. Keeley joined Unit in November 1983 as Senior Vice President, Exploration and Production. Prior to that time, Mr. Keeley co-founded (with Mr. Nikkel) Nike Exploration Company in January 1982 and, until November 2001, served as Executive Vice President and a director of that company. From 1977 until 1982, Mr. Keeley was employed by Cotton Petroleum Corporation, serving first as Manager of Land and from 1979 as Vice President and a director. Before joining Cotton, Mr. Keeley was employed for four years by Apexco, Inc. as Manager of Land and prior thereto he was employed by Texaco, Inc. for nine years. He received a Bachelor of Arts degree in Petroleum Land Management from the University of Oklahoma.

Mr. Schell joined Unit in January 1987, as its Secretary and General Counsel. In December 2002, he was elected to the additional position as Senior Vice President. From 1979 until joining Unit, Mr. Schell was Counsel, Vice President and a member of the Board of Directors of C&S Exploration, Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa Law School. He is a member of the Oklahoma and American Bar Association as well as being a member of the American Corporate Counsel Association and the American Society of Corporate Secretaries.

Mr. Merrill joined Unit in August 2003 and served as its Vice President, Finance until February, 2004 when he was elected to the position of Chief Financial Officer and Treasurer. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

Item 3. *Legal Proceedings*

We are a party to various legal proceedings arising in the ordinary course of our business, none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

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

No matters were submitted to our security holders during the fourth quarter of 2004.

PART II

Item 5. *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock trades on the New York Stock Exchange under the symbol "UNT." The following table identifies the high and low sales prices per share of our common stock for the periods indicated:

	2002		2003	
QUARTER	**High**	**Low**	**High**	**Low**
First	$ 18.60	$ 10.24	$ 21.99	$ 16.30
Second	$ 20.93	$ 16.01	$ 23.39	$ 19.14
Third	$ 19.25	$ 13.65	$ 22.60	$ 18.68
Fourth	$ 20.44	$ 16.71	$ 24.51	$ 18.40

On March 1, 2004 there were 1,763 record holders of our common stock.

We have never paid cash dividends on our common stock and currently intend to continue our policy of retaining earnings from our operations. Our loan agreement prohibits us from declaring and paying dividends (other than stock dividends) in any fiscal year in an amount greater than 25% of our preceding year's consolidated net income.

Item 6. *Selected Financial Data*

	Year Ended December 31,				
	1999 (1)	2000	2001	2002	2003
	(In thousands except per share amounts)				
Revenues	$ 102,352	$ 201,264	$ 259,179	$ 187,636	$ 302,584
Income Before Change in Accounting Principle	$ 3,048	$ 34,344	$ 62,766	$ 18,244	$ 48,864
Net Income	$ 3,048	$ 34,344	$ 62,766	$ 18,244	$ 50,189
Income Before Change in Accounting Principle per Common Share:					
Basic	$ 0.10	$ 0.96	$ 1.75	$ 0.47	$ 1.12
Diluted	$ 0.10	$ 0.95	$ 1.73	$ 0.47	$ 1.12
Net Income per Common Share:					
Basic	$ 0.10	$ 0.96	$ 1.75	$ 0.47	$ 1.15
Diluted	$ 0.10	$ 0.95	$ 1.73	$ 0.47	$ 1.15
Total Assets	$ 295,567	$ 346,288	$ 417,253	$ 578,163	$ 712,925
Long-Term Debt	$ 67,239	$ 54,000	$ 31,000	$ 30,500	$ 400
Other Long-Term Liabilities	$ 2,325	$ 3,597	$ 4,110	$ 5,439	$ 17,893
Cash Dividends Per Common Share	$ --	$ --	$ --	$ --	$ --

(1) Restated for the merger with Questa Oil and Gas Co.

See Item 7. Management's Discussion of Financial Condition and Results of Operations for a review of 2001, 2002 and 2003 activity.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

FINANCIAL CONDITION AND LIQUIDITY

Summary. Our financial condition and liquidity depends on the cash flow from our two principal subsidiaries and borrowings under our bank loan agreement. Our cash flow is influenced mainly by the prices we receive for our natural gas production, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production. At December 31, 2003, we had cash totaling $598,000 and we had borrowed $400,000 under our loan agreement.

Over the last six months of 2003 the average monthly natural gas price we received excluding the impact of hedging, ranged from $4.06 in October to $5.06 in December and the average Nymex Henry Hub daily price for the same time period ranged from $4.79 to $7.00. With the average Nymex contract settle price for the next twelve months at $5.40 on February 18, 2004, we expect natural gas prices to remain at levels that will increase demand for our rigs and provide upward movement on the rates we receive for our contract drilling services. There is, however, no assurance that these prices will actually be sustained throughout 2004.

The following is a summary of certain financial information as of December 31, 2003 and for the year ended December 31, 2003:

Working Capital	$ 20,931,000
Long-Term Debt.	$ 400,000
Shareholders' Equity.	$ 515,768,000
Ratio of Long-Term Debt to Total Capitalization. . . .	--%
Net Income.	$ 50,189,000
Net Cash Provided by Operating Activities. . . .	$ 121,712,000

The following table summarizes certain operating information for the years ended December 31, 2002 and 2003:

	2002	2003	Percent Change
Oil Production (Bbls) . . .	473,000	516,000	9%
Natural Gas Production (Mcf)	18,968,000	20,648,000	9%
Average Oil Price Received.	$ 21.54	$ 26.94	25%
Average Natural Gas Price Received.	$ 2.87	$ 4.87	70%
Average Number of Our Drilling Rigs in Use During the Period	39.1	62.9	61%

In December 2003, we acquired SerDrilco Incorporated for $35.0 million in cash. To finance the acquisition we sold 2.0 million shares of common stock for net proceeds of $42.1 million.

Our Bank Loan Agreement. At December 31, 2003, we 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 our acquisition of PetroCorp Incorporated, we replaced our loan agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although the current value of our assets under the latest loan value computation supported the full $150 million, we elected to set the loan commitment at $120 million in order to reduce financing costs since we are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We paid origination, agency and syndication fees of $515,000 at the inception of the new agreement, $40,000 of which will be paid annually and the remainder of the fees amortized over the four year life of the loan. Following the acquisition of PetroCorp Incorporated our borrowings were $90.0 million on February 18, 2004.

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

At our election, any 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% to 1.50% depending on the level of debt as a percentage of the total loan value and is payable at the end of each term or every 90 days whichever is less. Borrowings not under the Eurodollar Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At February 18, 2004, all of our $90.0 million debt was subject to the Eurodollar Rate.

The loan agreement includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain 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 our 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.

Hedging. Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow. We entered into a collar contract covering approximately 25% of our daily oil production for January and February of 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

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

On April 30, 2002, we entered into a collar contract covering approximately 19% of our 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, our natural gas hedging transactions increased natural gas revenues by $40,300. We did not have any hedging transactions outstanding at December 31, 2002.

During the first quarter of 2003, we entered into two collar contracts covering approximately 40% of our 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. We also entered into two collar contracts covering approximately 25% of our 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 of 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.

In January 2004, we entered into a natural gas collar covering approximately 14% of our estimated natural gas production. The transaction covers the periods of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. We also entered into an oil hedge covering approximately 40% of our estimated oil production. The transaction covers the periods of February through December of 2004 and has an average price of $31.40.

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

Impact of Prices for Our Oil and Natural Gas. With the acquisition of PetroCorp Incorporated (as further discussed in Note 12 of the Notes to Consolidated Financial Statements), natural gas comprises 86% of our total oil and natural gas reserves. Before the acquisition, natural gas comprised 89% of our reserves. Any significant change in natural gas prices has a material affect on our revenues, cash flow and the value of our oil and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our production in 2003, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax operating cash flow. Our 2003 average natural gas price was $4.87 compared to an average natural gas price of $2.87 for 2002. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow based on our production in 2003. Our 2003 average oil price was $26.94 compared with an average oil price of $21.54 received in 2002.

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

We sell most of our natural gas production to third parties under month-to-month contracts. Several of these buyers have experienced financial complications resulting from the recent investigations into the energy trading industry. The long-term implications to the energy trading business, as well as to oil and natural gas producers, because of these investigations remains, to be determined. We continue to evaluate the information available to us about our buyers and try to reduce any possible future adverse impact to us. Presently we believe that our buyers will be able to perform their commitments to us. For 2003, purchases by Cinergy Marketing & Trading LP accounted for approximately 17% of our oil and natural gas revenues while purchases by Centerpoint Energy Gas accounted for approximately 16% of our oil and natural gas revenues. We own a 16.7% limited partner interest in Eagle Energy Partners I LP, whose purchases, which are competitively marketed, accounted for 6% of our oil and natural gas revenues in 2003. We have increased our sales to Eagle Energy Partners I LP since we first started selling natural gas to them in August, 2003. For the period August through December 2003 Eagle has purchased 16% of our oil and natural gas revenues and they marketed approximately 37% of the natural gas volumes we sold for ourselves and third parties during the same five month period.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when to incur such costs. We drilled 149 wells (61.57 net wells) in 2003 compared to 96 wells (51.87 net wells) in 2002. Our total capital expenditures for oil and natural gas exploration and acquisitions in 2003 totaled $73.3 million excluding capitalized cost for the recording of the plugging liability associated with our wells. Based on current prices, we plan to drill an estimated 165 to 175 wells in 2004 and total capital expenditures for oil and natural gas exploration and acquisitions is planned to be around $95 million.

Contract Drilling. Our drilling work is subject to many factors that influence the number of rigs we have working as well as the costs and revenues associated with such work. These factors include competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our rigs and our ability to supply the equipment needed. We have not encountered major difficulty in hiring and keeping rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs increases rapidly in the future, shortages of experienced personnel may limit our ability to increase the number of rigs we could operate.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. In the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when 52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001 and stabilized with between 30 and 35 rigs operating in the first half of 2002. The rates received for our rigs also began to fall until they reached a low of $7,275 per day in February of 2003. Natural gas and oil prices once again began to rise during the last half of 2002 and in the second quarter of 2003 through the remainder of the year both demand for our rigs and dayrates continued to improve. In December 2003 the average dayrate on the 75 rig fleet owned by us throughout 2003 was approximately $8,200 per day and the 12 Service rigs added in December 2003 had a dayrate of approximately $7,500 making the average dayrate for the 88 rig fleet $8,130 in December 2003. The average use of our rigs in 2003 was 62.9 rigs (83%) compared with 39.1 rigs (63%) for 2002. Our average dayrate in 2003 was $7,808 compared to $7,716 for 2002. Based on the average utilization of our rigs in 2003, a $100 per day change in dayrates has a $6,290 per day ($2,296,000 annualized) change in our pre-tax operating cash flow. Utilization and dayrates for our drilling rigs will depend mainly on the price of natural gas.

Our contract drilling subsidiary provides drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. During 2003, we drilled 43 wells for our exploration and production subsidiary. Per regulations provided by the

Securities and Exchange Commission, the profit received by our contract drilling segment of $841,000 and $1,883,000 during 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.

Drilling Acquisitions and Capital Expenditures. On December 8, 2003, we acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the three years following the acquisition. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and an equipment yard in and near Borger, Texas. For our contract drilling operations during 2003, we incurred $71.9 million in capital expenditures, which includes $35.0 million in cash and $10.9 million for goodwill resulting from deferred tax liabilities recorded in connection with the SerDrilco acquisition. For the year 2004, we have budgeted capital expenditures of approximately $30 million for our contract drilling operations.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 10 oil and natural gas partnerships which were formed privately and publicly. The partnership's revenues and costs are shared under formulas prescribed in each limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2001, 2002 and 2003, the total paid to us for all of these fees was $1,107,000, $929,000 and $873,000, respectively. We expect the fees to be about the same in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

We own a 40% equity interest in Superior Pipeline Company LLC, an Oklahoma Limited Liability Company. Superior is a natural gas gathering and processing company. Our investment, including our share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets in our accompanying 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.

We also own 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. Eagle was marketing approximately 46% of the natural gas volumes we sell for ourselves and third parties in December 2003 and during February 2004 they are marketing 48%.

Contractual Commitments. We have the following contractual obligations at December 31, 2003:

Contractual Obligations	Payments Due by Period Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank Debt(1)	$ 400	$ --	$ --	$ 400	$ --
Retirement Agreement(2)	1,650	300	600	600	150
Operating Leases(3)	3,555	719	1,424	954	458
Total Contractual Obligations	$ 5,605	$ 1,019	$ 2,024	$ 1,954	$ 608

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(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt. The obligation is presented in accordance with the terms of the loan agreement signed on January 30, 2004.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, will be paid in monthly payments of $25,000 starting in July 2003 and continuing through June 2009. The liability as presented above is undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma and Houston, Texas under the terms of operating leases expiring through January 31, 2010 along with leasing space on short-term commitments to stack excess rig equipment and production inventory. In the first quarter of 2003, we renegotiated our rental agreement for the Tulsa office reducing the price per square foot while adding additional space and lengthening the term of the agreement to January 31, 2010.

At December 31, 2003, we also have the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Amount Committed or Accrued	Amount of Commitment Expiration Per Period: Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred Compensation Agreement(1)	$ 1,829	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,545	$ 412	Unknown	Unknown	Unknown
Plugging Liability(3)	$ 11,994	$ 303	$ 481	$ 882	$ 10,328
Gas Balancing Liability(4)	$ 1,191	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(5)	Unknown	Unknown	Unknown	Unknown	Unknown

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

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan.

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

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

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2004, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, upon the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $1,000 and $106,000 in 2002 and 2003, respectively, for such limited partners' interests. No repurchases were made in 2001.

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

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices on December 31, 2003 ($5.67 per Mcf for natural gas and $32.52 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas prices remain erratic and any significant declines below prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

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

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

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

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

EFFECTS OF INFLATION

The effect of inflation in the oil and natural gas industry is primarily driven by the prices realized for oil and natural gas. Increased commodity prices increase demand for contract drilling rigs and services which support higher rig activity. This in turn affects the overall demand for our rigs and the dayrates we can obtain for our contract drilling services. Before 1999, the effect of inflation on our operations was minimal due to low inflation rates, relatively low natural gas and oil prices and moderate demand for our contract drilling services. Over the last four years natural gas and oil prices have been more volatile, and during periods of higher utilization we have experienced increases in labor cost and the cost of services to support our rigs. During this same period when commodity prices did decline labor rates did not come back down to the levels incurred before the increases. If natural gas prices increased substantially for a long period, shortages in support equipment such as drill pipe, third party services and qualified labor could occur resulting in additional corresponding increases in our material and labor costs. These conditions may limit our ability to realize improvements in operating profits. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates and the prices we receive for our oil and natural gas.

NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2003 we adopted Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations” (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. We own 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). We do not have any assets restricted for the purpose of settling the plugging liabilities.

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.

On January 17, 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. FIN 46, as amended, was effective for us in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, did not have an impact on our 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, we will have to adopt FIN 46, as amended, in the quarter ending March 31, 2004. We are still evaluating FIN 46 with regard to these types of entities in which we have an ownership interest, primarily our oil and gas partnerships and our equity investment in Superior pipeline. FIN 46 may require full consolidation of these entities which would increase our total assets with an offsetting minority interest for the percentage not owned by Unit. There will be no net impact to our 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 us on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the notes to our financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, we, like many other oil and gas companies, have included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective.

Our results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

At December 31, 2002 and 2003, we had undeveloped leaseholds of approximately $13.2 million and $14.8 million, respectively that would be classified on our balance sheets 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 us to make the disclosures set forth under FAS 142 related to these interests.

We intend to continue to classify our oil and gas mineral extraction rights as tangible oil and gas properties until further guidance is provided.

RESULTS OF OPERATIONS

2003 versus 2002

Provided below is a comparison of selected operating and financial data for the year of 2002 versus the year of 2003:

	2002	2003	Percent Change
Total Revenue	$ 187,636,000	$ 302,584,000	61%
Income Before Change in Accounting Principle	$ 18,244,000	$ 48,864,000	168%
Net Income	$ 18,244,000	$ 50,189,000	175%
Oil and Natural Gas:			
Revenue	$ 67,959,000	$ 116,609,000	72%
Average natural gas price (Mcf)	$ 2.87	$ 4.87	70%
Average oil price (Bbl)	$ 21.54	$ 26.94	25%
Natural gas production (Mcf)	18,968,000	20,648,000	9%
Oil production (Bbl)	473,000	516,000	9%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.04	$ 1.14	10%
Depreciation, depletion and amortization ($346,000 write off of interest in Shenandoah in 2002)	$ 23,338,000	$ 27,343,000	17%
Drilling:			
Revenue	$ 118,173,000	$ 183,146,000	55%
Percentage of revenue from daywork contracts	91%	98%	
Average number of rigs in use	39.1	62.9	61%
Average dayrate on daywork contracts	$ 7,716	$ 7,808	1%
Depreciation	$ 14,684,000	$ 23,644,000	61%
General and Administrative Expense	$ 8,712,000	$ 9,222,000	6%
Interest Expense	$ 973,000	$ 693,000	(29%)
Average Interest Rate	3.0%	2.2%	(27%)
Average Long-Term Debt Outstanding	$ 24,771,000	$ 20,722,000	(16%)

Oil and natural gas revenues and net income were all positively affected by the higher prices we received for both our oil and natural gas during 2003 as compared to 2002. Production for both oil and natural gas was also up between the comparative years. Total operating cost increased primarily from higher gross production taxes resulting from higher revenues. Total depreciation, depletion and amortization ("DD&A") on our oil and natural gas properties increased due to higher production volumes and an increase in the DD&A rate in 2003, which resulted from higher development drilling cost per equivalent Mcf.

Operator demand for our rigs increased gradually throughout 2003 as natural gas prices increased in 2003 versus 2002 and resulted in higher rig use and dayrates for our rigs. Higher dayrates were offset by higher rig expense as we experienced a 121% increase in ad valorem taxes on our rigs and a 175% increase in worker's compensation expense. We expect both of these expenses, along with increased demand for quality labor within the industry, to keep upward pressure on rig costs throughout 2004. Approximately 2% of our total drilling revenues in 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Nine percent of our total drilling revenues came from footage and turnkey contracts in 2002. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002 and additional rig use.

General and administrative expense was higher in 2003 due to an increase in general liability insurance, director and officer insurance and increased corporate administrative cost. Our total interest expense is lower due to lower interest rates and a substantial reduction in our average long-term debt. Income tax expense increased 202% primarily due to a 180% increase in income before income taxes. Our effective tax rate for 2002 was 34.4% versus 37.2% in 2003. The impact of higher statutory depletion and other permanent differences reduced by the impact of state income taxes was the cause for the lower effective tax rate in 2002.

Net income includes $1.3 million of income due to an accumulated change in accounting principle for the implementation of 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. We own 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 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 2003.

2002 versus 2001

Provided below is a comparison of selected operating and financial data for the year of 2002 versus the year of 2001:

	2001	2002	Percent Change
Total Revenue	$ 259,179,000	$ 187,636,000	(28%)
Net Income	$ 62,766,000	$ 18,244,000	(71%)
Oil and Natural Gas:			
Revenue	$ 90,237,000	$ 67,959,000	(25%)
Average natural gas price (Mcf)	$ 4.00	$ 2.87	(28%)
Average oil price (Bbl)	$ 23.62	$ 21.54	(9%)
Natural gas production (Mcf)	18,864,000	18,968,000	1%
Oil production (Bbl)	492,000	473,000	(4%)
Depreciation, depletion and amortization rate (Mcfe)	$ 0.91	$ 1.04	14%
Depreciation, depletion and amortization (includes $2,083,000 and $346,000 write off of interest in Shenandoah in 2001 and 2002, respectively)	$ 22,116,000	$ 23,338,000	6%
Drilling:			
Revenue	$ 167,042,000	$ 118,173,000	(29%)
Percentage of revenue from daywork contracts	99%	91%	
Average number of rigs in use	46.3	39.1	(16%)
Average dayrate on daywork contracts	$ 10,044	$ 7,716	(23%)
Depreciation	$ 13,888,000	$ 14,684,000	6%
General and Administrative Expense	$ 8,476,000	$ 8,712,000	3%
Interest Expense	$ 2,818,000	$ 973,000	(65%)
Average Interest Rate	5.7%	3.0%	(47%)
Average Long-Term Debt Outstanding	$ 44,995,000	$ 24,771,000	(45%)

Oil and natural gas revenues, net income were all negatively affected by lower prices received for both oil and natural gas during 2002 compared to 2001. Production in equivalent Mcf was almost the same in 2002 as in 2001. Total operating cost decreased due to lower gross production taxes resulting from lower revenues. Total DD&A on our oil and natural gas properties increased due to the increase in the DD&A rate in 2002, which resulted from higher development drilling cost per equivalent Mcf. The increase would have been larger, but included in 2001 DD&A was the write down of our investment in Shenandoah Resources LTD. In 2001 Shenandoah started experiencing financial difficulties and its stock price declined, so we took a write down in our investment of $2.1 million to reduce the carrying value to the market value of Shenandoah's stock. In August 2002, the assets of Shenandoah were liquidated for the benefit of the secured creditors and, as a result, our remaining investment of $346,000 in Shenandoah was written off.

Reduced natural gas prices, especially in the fourth quarter of 2001 and the first quarter of 2002, caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. Total drilling operating costs were relatively unchanged between the two years. Approximately 9% of our total drilling revenues in 2002 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. One percent of our total drilling revenues came from footage and turnkey contracts in 2001. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002. The increase was partially offset by lower rig use.

General and administrative expense was higher in 2002 due to increases in labor cost, insurance expense and outside contract services. In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense plus accrued interest will be paid in $25,000 monthly payments starting in July 2003 and continuing through June 2009. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt. Income tax expense decreased 73% primarily due to a 72% decrease in income before income taxes.

Item 7a. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, prices we received for our oil and natural gas production fluctuated and such fluctuation is expected to continue. The price of natural gas also effects the demand for our rigs and the amount we can charge for the use of the rigs. Based on our 2003 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow.

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

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase Prime Rate or the Eurodollar Rate. At our election, borrowings under our revolving credit facility may be fixed at the Eurodollar Rate for periods up to 180 days. Historically, we have not utilized any financial instruments, such as interest rate swaps, to manage our exposure to increases in interest rates. However, we may use financial instruments in the future should our assessment of future interest rates warrant there use. Based on our average outstanding long-term debt in 2003, a 1% change in the floating rate would change our annual pre-tax cash flow by approximately $207,000.

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.

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME - CONTINUED

	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 reclasification - derivative settlements	--	--	--	(1,258)	--	(1,258
Balances, December 31, 2001	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,162

The accompanying notes are an integral part of the

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 Comprehen-sive Income	Treasury Stock	Total
			(In thousands except share amounts)			
Balances, January 1, 2002	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,16
Net Income	--	--	18,244	--	--	18,24
Activity in employee compensation plans (113,133 shares)	23	1,156	--	--	296	1,47
Issuance of stock for acquisition (7,220,000 shares)	1,444	121,047	--	--	--	122,49
Other comprehensive income (net of tax of $15 and $15):						
Change in value of cash flow derivative instruments used as cash flow hedges	--	--	--	25	--	2
Adjustment reclasifica-tion - derivative settlements	--	--	--	(25)	--	(2
Balances, December 31, 2002	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,37

The accompanying notes are an integral part of the

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, 2003	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,37
Net Income	--	--	50,189	--	--	50,18
Activity in employee compensation plans (252,612 shares)	49	2,018	--	--	--	2,06
Issuance of 2,000,000 shares of common stock)	400	41,740	--	--	--	42,14
Other comprehensive income (net of tax of $3 and $3):						
Change in value of cash flow derivative instruments used as cash flow hedges	--	--	--	(4)	--	
Adjustment reclasification - derivative settlements	--	--	--	4	--	
Balances, December 31, 2003	$ 9,117	$ 307,938	$198,713	$ --	$ --	$ 515,76

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

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

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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) 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.

	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

	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

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 share (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	128,853

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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	Totals
		(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

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

	USA	Canada	Totals
		(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
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	Totals
		(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

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

Item 9a. Controls and Procedures.

(a) **Evaluation of Disclosure Controls and Procedures**

The company maintains "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act"), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is collected and communicated to management, including the company's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards. Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the company's disclosure controls and procedures were effective to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to them by others within those entities.

(b) **Changes in Internal Control Over Financial Reporting**

As of the last quarter, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The information regarding Directors and Executive Officers appearing under the headings "Item 1: Election of Directors", and "Other Matters" of our 2004 Proxy Statement is incorporated by reference in this section. The information under the heading "Executive Officers" in Items 1 and 2 of this Form 10-K is also incorporated by reference in this section.

Item 11. *Executive Compensation*

The information appearing under the headings "Directors' Compensation and Benefits", "Executive Compensation", "Termination of Employment & Change in Control Arrangements", "Compensation Committee Interlocks and Insider Participation" and "Report of the Compensation Committee" of our 2004 Proxy Statement is incorporated by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information appearing under the heasding "Ownership of Our Common Stock by Beneficial Owners and Management" of our 2004 Proxy Statement is incorporated by reference.

Item 13. *Certain Relationships and Related Transactions*

The information appearing under the heading "Other Matters" of our 2004 Proxy Statement is incorporated by reference.

ITEM 14. Principal Accounting Fees and Services.

The information appearing under the headings "Report of Audit Committee", "Principal Accounting Fees and Services" and "Ratification of Appointment of Auditors" of our 2004 Proxy Statement is incorporated by reference.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:

- Consolidated Balance Sheets as of December 31, 2002 and 2003
- Consolidated Statements of Income for the years ended December 31, 2001, 2002 and 2003
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2001, 2002 and 2003
- Consolidated Statements of Cash Flows for the years ended December 31, 2001, 2002 and 2003
- Notes to Consolidated Financial Statements
- Report of Independent Auditors

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2001, 2002 and 2003:

- Schedule II - Valuation and Qualifying Accounts and Reserves

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

3. Exhibits:

2.6.1 Amended and Restated Stock Purchase Agreement dated as of June 24, 2002 by and among Unit Corporation, George B. Kaiser and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.1 to Form 8-K dated August 27,2002).

2.6.2 Amended and Restated Share Purchase Agreement dated as of June 24, 2002, by and among Unit Corporation, Kaiser Francis Charitable Income Trust B and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.2 to Form 8-K dated August 27, 2002).

3.1 Restated Certificate of Incorporation of Unit Corporation (filed as Exhibit 3.1 to Form S-3 (file No. 333-83551), which is incorporated herein by reference).

3.2 By-Laws of Unit Corporation (filed as Exhibit 3.2 to Unit's Form 8-K to Form S-3 (file No. 333-83551), which is incorporated herein by reference).

4.2.3 Form of Common Stock Certificate (filed as Exhibit 4.1 on Form S-3 as S.E.C. File No. 333-83551, which is incorporated herein by reference).

4.2.6 Rights Agreement between Unit Corporation and Chemical Bank, as Rights Agent (filed as Exhibit 1 to Unit's Form 8-A filed with the S.E.C. on May 23, 1995, File No. 1-92601 and incorporated herein by reference).

4.2.7 First Amendment of Rights Agreement dated May 19, 1995, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as Exhibit 4 to Unit's Form 8-K dated August 23, 2001, which is incorporated herein by reference).

4.2.8 Second Amendment of the Rights Agreement, dated August 14, 2002, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002, which is incorporated herein by reference).

4.3 Indenture (filed as Exhibit 4.3 to Unit's Form S-3 filed with the S.E.C. File No. 333-104165, which is incorporated herein by reference).

10.1.26 Loan Agreement dated January 30, 2004 (filed herein).

10.2.2 Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company's Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).

10.2.10 Unit 1984 Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Oil and Gas Program's Registration Statement Form S-1 as S.E.C. File No. 2-92582, which is incorporated herein by reference).

10.2.21* Unit Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to Unit's Registration Statement on Form S-4 as

S.E.C. File No. 33-7848, which is incorporated herein by reference).

10.2.22* The Company's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No’s. 33-19652, 33-44103 and 33-64323 which is incorporated herein by reference).

10.2.23* Unit Corporation Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724, which is incorporated herein by reference).

10.2.24* Unit Corporation Employees' Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).

10.2.25 Unit Consolidated Employee Oil and Gas Limited Partnership Agreement. (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

10.2.27* Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

10.2.30* Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as an Exhibit to Unit’s Annual Report under the cover of Form 10-K for the year ended December 31, 1996, which is incorporated herein by reference).

10.2.32* Unit Corporation Separation Benefit Plan for Senior Management (filed as an Exhibit to Unit’s Quarterly Report under cover of Form 10-Q for the quarter ended September 30, 1997, which is incorporated herein by reference).

10.2.35 Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under the cover of Form 10-K for the year ended December 31, 1999).

10.2.36* Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).

10.2.37* Unit Corporation's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No. 333-39584 which is incorporated herein by reference).

10.2.38 Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).

10.2.39* Form of Unit Corporation Key Employee Change of Control Contract entered into with certain of Unit's officers (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).

10.2.40 Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10 to Unit's Form 8-K dated August 23, 2001, which is incorporated herein by reference).

10.2.41 Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2001).

10.2.42 Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002).

10.2.43 Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).

21 Subsidiaries of the Registrant (filed herein).

23.1 Consent of Independent Accountants (filed herein).

23.2 Consent of Independent Petroleum Engineers (filed herein).

31.1 Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act (filed herein).

31.2 Certification of Chief Financial Officer under Rule 13a -14(a) of the Exchange Act (filed herein).

32.1 Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).

99.2 Separation Agreement, dated May 11, 2001, between the Registrant and Mr. Kirchner (filed as Exhibit 99.A4 to Unit's Form 8-K dated May 18, 2001, which is incorporated herein by reference).

* Indicates a management contract or compensatory plan identified pursuant to the requirements of Item 14 of Form 10-K.

(b) Reports on Form 8-K:

On October 22, 2003, we filed a report on Form 8-K under items 7 and 12. This report announced our results of operations and financial condition for the quarter ended September 30, 2003. The press release regarding this announcement was furnished as an exhibit.

On October 27, 2003, we filed a report on Form 8-K under items 5 and 7. This report announced that our Board of Directors has elected Mr. Mark E. Monroe to the Company's Board of Directors. The press release regarding this announcement was furnished as an exhibit.

On November 21, 2003, we filed a report on Form 8-K under items 5 and 7. This report announced that we signed an agreement to acquire Serdrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, a U.S. land drilling company located in Borger, Texas, for $35.0 million in cash and an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the next three years. The press release regarding this announcement was furnished as an exhibit.

On December 8, 2003, we filed a report on Form 8-K under items 7 and 9. This report announced the completion of the acquisition of SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC. We also announced we intend to offer 2 million shares of our common stock pursuant to an effective shelf registration statement filed with the Securities and Exchange Commission. The press releases regarding both of the announcements were furnished as exhibits.

On December 9, 2003, we filed a report on Form 8-K/A under item 7. This report updated the proforma financial statements related to the acquisition of CREC Rig Acquisition Company LLC and CDC Drilling Company.

On December 10, 2003, we filed a report on Form 8-K under items 7 and 9. This report announced that the previously announced public offering of 2 million shares of our common stock was priced at $22.00 per share and we anticipate the transaction will close on December 15, 2003. The press release regarding this announcement was furnished as an exhibit.

On December 11, 2003, we filed a report on Form 8-K under items 5 and 7. This report filed exhibits in connection with a prospectus supplement relating to the issuance and sale in an underwritten public offering of 2,000,000 shares of the Company's common stock.

Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
		(In thousands)		
Year ended December 31, 2001	$ 919	$ --	$ 315	$ 604
Year ended December 31, 2002	$ 604	$ 603	$ 4	$ 1,203
Year ended December 31, 2003	$ 1,203	$ 645	$ 625	$ 1,223

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

UNIT CORPORATION

DATE: March 10, 2004 By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 10th day of March, 2004.

Name	Title
/s/ John G. Nikkel **JOHN G. NIKKEL**	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)
/s/ Larry D. Pinkston **LARRY D. PINKSTON**	Director, President, Chief Operating Officer
/s/ David T. Merrill **DAVID T. MERRILL**	Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Stanley W. Belitz **STANLEY W. BELITZ**	Controller (Principal Accounting Officer)
/s/ J. Michael Adcock **J. MICHAEL ADCOCK**	Director
/s/ Don Cook **DON COOK**	Director
/s/ King P. Kirchner **KING P. KIRCHNER**	Director
/s/ Mark E. Monroe **MARK E. MONROE**	Director
/s/ William B. Morgan **WILLIAM B. MORGAN**	Director
/s/ John H. Williams **JOHN H. WILLIAMS**	Director
/s/ John S. Zink	

-------------------------------- Director

JOHN S. ZINK

EXHIBIT INDEX

Exhibit No.	Description	Page
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10.2.43	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.	
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