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, 2001

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.

Aggregate Market Value of the Voting Stock Held By Non-affiliates on March 7, 2002 - $390,907,479

Number of Shares of Common Stock Outstanding on March 7, 2002 – 36,074,419

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 1, 2002 are incorporated by reference in Part III.

FORM 10-K
UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2001

PART I

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

Through our wholly owned subsidiaries, 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 self. We were founded in 1963 as a contract drilling company. Today our contract drilling operations and our exploration and production operations are carried out primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins and the Texas Gulf Cost. Our contract drilling operations are also engaged in the East Texas and Rocky Mountain region.

Our executive offices are located at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; telephone number (918) 493-7700. We also have regional offices in Oklahoma City, Oklahoma, Woodward, Oklahoma, Booker, Texas, Houston, Texas and Casper, Wyoming. When used in this report, the terms Corporation, Unit, our, we and its refer to Unit Corporation and, at times, Unit Corporation and/or one or more of its subsidiaries.

LAND CONTRACT DRILLING OPERATIONS

We drill onshore natural gas and oil wells for a wide range of customers through our wholly owned subsidiary Unit Drilling Company. 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, are replaced or rebuilt on a periodic basis, while other components, such as the substructure, mast and drawworks, can be utilized 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.

While natural gas prices were high in early 2001, we continued to add to our rig fleet. In January 2001, we purchased a 750 horse power diesel electric rig with a 13,000 foot depth capacity for $3.2 million. In February 2001, we purchased a 1,000 horse power, winterized mechanical rig, with a 16,000 foot depth capacity, for $2.5 million. In May we acquired two diesel electric rigs with depth capacities of 16,000 and 20,000 feet, for $7.8 million. We also acquired a 16,000 foot depth capacity diesel electric rig.

This rig will, depending on industry conditions and additional capital requirements, be placed in service when conditions warrant. The addition of these five rigs brings our fleet to 55 at December 31, 2001, 54 of which are currently capable of operating. Our rigs have depth capacities ranging from 9,500 to 40,000 feet. As of March 1, 2002 twenty-nine of our rigs were located in the Anadarko Basin of Oklahoma and Texas, 6 in the Arkoma Basins of Oklahoma while 12 were located in the East Texas and Gulf Coast Region and 8 in the Rocky Mountain region. As of February 20, 2002, 34 of our drilling rigs were operating under contract.

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.

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

	Year Ended December 31,				
	1997	1998	1999	2000	2001
Number of Rigs Owned at End of Period	34.0 (1)	34.0	47.0 (2)	50.0 (3)	55.0 (4
Average Number of Rigs Owned During Period	25.1	34.0	37.3	47.0	51.8
Average Number of Rigs Utilized (5)	20.0	22.9	23.1	39.8	46.3
Utilization Rate (5)	80%	67%	62%	85%	90%
Average Revenue Per Day (6)	$6,309	$6,394	$6,582	$7,432	$9,879
Total Footage Drilled (Feet in 1000's)	1,736	2,203	2,211	3,650	4,008
Number of Wells Drilled	167	198	197	316	361

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(1) Includes 10 rigs acquired in the fourth quarter of 1997.

(2) Includes 13 rigs acquired in September 1999.

(3) Includes one rig acquired at the 2000 year-end and two additional rigs that were completing construction.

(4) Includes 5 rigs acquired during the first 7 months of 2001.

(5) Utilization rates are based on a 365-day year and are calculated by dividing the number of rigs utilized by the total number of rigs owned during the period, including stacked rigs. A rig is considered utilized when it is operating or being moved, assembled or dismantled under contract.

(6) Represents total revenues from contract drilling operations divided by the total number of days rigs were being utilized for the period.

The following table sets forth, as of February 20, 2002, the type and approximate depth capability of each of our drilling rigs:

Rig#	Type	Approximate Depth Capability (feet)
1	BDW 650	13,000
2	BDW 650	13,000
3	BDW 650	13,500
4	Gardner Denver 500	11,000
5	U-15 Unit Rig	11,000
6	BDW 800	16,000
8	Gardner Denver 800	16,000
9	BDW 800	16,000
10	BDW 450T	9,500
11	Gardner Denver 700	15,000
12	BDW 800	16,000
14	Gardner Denver 700	15,000
15	Mid-Continent 914-C	20,000
16	U-15 Unit Rig	11,000
17	Brewster N-75	15,000
18	BDW 650	12,500
19	Gardner Denver 500	12,000
20	Gardner Denver 700	15,000
21	Gardner Denver 700	15,000
22	BDW 800	16,000
23	Gardner Denver 700	14,000
24	Gardner Denver 700	14,000
25	Gardner Denver 700	15,000
26	National 610 E	13,500
27	BDW 650	13,000
28	Continental Emsco D-3	16,000
29	Brewster N-75A	15,000
30	BDW 1350-M	20,000
31	Shufelt 600	12,500
32	Brewster N-75	15,000
33	BDW 800	16,000
34	National 110-UE	20,000
35	Continental Emsco C-1	20,000
36	Gardner Denver 1500-E	25,000
37	Mid-Continent 914-EC	20,000
38	Mid-Continent 1220-EB	25,000
39	Mid-Continent U-36-A	12,000
40	BDW 800	16,000
100	National 80-UE	16,000 (1)
101	Continental Emsco D-3	16,000
102	Continental Emsco A-1500	20,000
112	Ideco E-3000	25,000
166	OIME E-3000	25,000
180	OIME E-3000	25,000
182	OIME E-3000	30,000
184	OIME E-3000	30,000
201	OIME E-4000	40,000
203	OIME E-2000	25,000
232	Continental Emsco D-3 II	16,000
233	Continental Emsco C-1 III	20,000
234	Continental Emsco D-3 II	16,000
235	Continental Emsco C-1 II	20,000
236	Gardner Denver 800	16,000
237	Continental Emsco C-1 II	20,000

254	OIME E-2000	25,000

(1) Rig 100 was acquired in 2001 and will not be refurbished and marketed by us until industry conditions improve.

During most of the past 18 years, our contract drilling operations encountered significant competition due to depressed levels of activity. In the last half of 1999 through the first half of 2001, as oil and natural gas prices increased, the demand for our contract drilling services increased rapidly. However starting in October 2001 we began to experience rapidly declining demand for our rigs as the prices of natural gas began to fall from the high prices reached in January, 2001. We anticipate that competition within the industry will, for the foreseeable future, continue to adversely affect us.

Drilling Contracts. Our drilling contracts are predominantly obtained through competitive bidding. Normally, our contracts are for a single well with the terms and rates varying depending upon the nature and duration of the work, the equipment and services supplied and other matters. The contracts obligate us to 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 upon payment of a fee. These contracts also specify certain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution. The specific provisions regarding the responsibility for, the extent of and the type of claims covered is subject to negotiation on a contract by contract basis.

Our compensation under a contract is based on the type of contract used. The contracts we use are generally one of three types: a daywork; a footage; or a turnkey contract. Additional compensation may also be involved for special risks and unusual conditions. Under daywork contracts, we provide the drilling rig with the required personnel to the operator who supervises the drilling of the contracted well. Our compensation is based on a negotiated rate for each day the rig is utilized. Footage contracts usually require us to bear some of the drilling costs in addition to providing the rig. We are compensated on a negotiated rate, per foot drilled, upon completion of the well. Under turnkey contracts, we contract to drill a 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 compensated when the contract provisions have been satisfied.

Drilling operations under a turnkey contract, in particular, may result in us incurring 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 2001, we drilled one turnkey well and turnkey revenue represented less than one percent of our contract drilling revenues as compared to 9 percent for 2000. We had one turnkey contract in progress at December 31, 2001. 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 2001, 10 contract drilling customers accounted for approximately 49 percent of our total contract drilling revenues. Approximately 4 percent of our total contract drilling revenues were generated from drilling operations performed on oil and natural gas properties of which we were the operator (including properties owned by limited partnerships for which we acted as general partner).

Further information relating to contract drilling operations is presented in Notes 1 and 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

OIL AND NATURAL GAS OPERATIONS

In 1979, we began to develop our exploration and production operations to diversify our contract drilling revenues. Our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities.

As of December 31, 2001, we had estimated net proved reserves of 4,343 Mbbls and 228,254 MMcf. Our producing oil and natural gas interests, undeveloped leaseholds and related assets are located primarily 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. As of December 31, 2001, we had an interest in a total of 2,974 wells in the United States, 688 of which we are also the operator of. We also had an interest in 64 wells located in Canada.

Our technical staff generates the majority of our development and exploration prospects. When we are the operator of a property, we generally employ our own drilling rigs and our own engineering staff supervises the drilling operation.

Well and Leasehold Data. The tables below set forth certain information regarding our oil and natural gas exploration and development drilling activities for the periods indicated:

	Year Ended December 31,					
	1999		2000		2001	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Oil	-	-	-	-	1	.01
Natural gas	-	-	2	1.63	8	3.60
Dry	-	-	-	-	5	4.46
Total	-	-	2	1.63	14	8.07
Development:						
Oil	1	.48	7	1.45	6	1.06
Natural gas	55	19.23	75	28.51	87	33.51
Dry	10	5.47	17	8.56	18	10.80
Total	66	25.18	99	38.52	111	45.37
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil – USA	783	224.10	799	278.06	786	279.06
Oil – Canada	-	-	-	-	-	-
Gas – USA	1,950	403.50	2,088	431.11	2,188	457.38
Gas – Canada	64	1.60	64	1.60	64	1.60
Total	2,797	629.20	2,951	710.77	3,038	738.04

On February 20, 2002, Unit was participating in the drilling of 3 gross (1.99 net) wells in the United States.

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

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
1999:				
USA	548,011	142,472	55,989	35,245
Canada	39,040	976	25,293	25,293
Total	587,051	143,448	81,282	60,538
2000:				
USA	564,780	153,507	61,487	39,480
Canada	39,040	976	26,243	13,121
Total	603,820	154,483	87,730	52,601
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

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 periods indicated:

	Year Ended December 31,		
	1999	**2000**	**2001**
Average Sales Price per Barrel of Oil Produced:			
USA	$ 17.48	$ 26.95	$ 23.62
Canada	-	-	-
Average Sales Price per Mcf of Natural Gas Produced:			
USA	$ 2.05	$ 3.91	$ 4.00
Canada	$ 1.81	$ 2.39	$ 4.21
Oil Production (Mbbls):			
USA	424	488	492
Canada	-	-	-
Total	424	488	492
Natural Gas Production (MMcf):			
USA	17,402	19,239	18,819
Canada	35	46	45
Total	17,437	19,285	18,864
Average Production Expense per Equivalent Mcf:			
USA	$ .59	$ .74	$ .86
Canada	$ .56	$ .42	$ .51

Reserves. The following table sets forth our estimated proved developed and undeveloped oil and natural gas reserves at the end of each of the years indicated:

	Year Ended December 31,		
	1999	**2000**	**2001**
Oil (Mbbls):			
USA	4,527	4,183	4,343
Canada	-	-	-
Total	4,527	4,183	4,343
Natural gas (MMcf):			
USA	186,770	215,196	227,865
Canada	569	441	389
Total	187,339	215,637	228,254

Further information relating to oil and natural gas operations is presented in Notes 1, 10 and 12 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

VOLATILE NATURE OF OUR OIL AND NATURAL GAS MARKETS; FLUCTUATIONS IN PRICES

Our revenues, operating results, cash flows and future rate of growth are significantly affected by the prevailing prices for natural gas and oil. Historically, oil and natural gas prices have been volatile, and we expect that they will continue to be volatile. Oil and natural gas prices increased substantially in the last half of 1999 and throughout 2000 and by January 2001, the average price we received for natural gas reached $9.35 per Mcf. Prices however, started to decline sharply thereafter and by September 2001, the average price we received for natural gas was $2.05 per Mcf. The average price we received for oil reached a high of $28.13 per barrel in February 2001. Oil prices then started to decline and we received the lowest average price of the year for oil of $16.28 per barrel in December 2001.

Because natural gas makes up the biggest part of our oil and natural gas reserves, changes in natural gas prices have a disproportionate impact on our financial results than do oil price changes.

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;
- 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 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 original terms ranging from one month to several years at prices primarily determined on a daily basis. Most of these contracts contain provisions for readjustment of price, termination and other terms customary in the industry.

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. Decreased oil and natural gas prices during 1998 and early 1999 adversely affected our contract drilling activity by lowering the demand for our rigs and reducing the rates we were able to charge for our drilling services.

With the increase in oil and natural gas prices starting in the last half of 1999 and continuing through January 2001 our dayrates and rig utilization increased substantially.

Natural gas prices began to fall in February, 2001, and as a result, we began to experience less demand for our drilling rigs starting in October, 2001 and the rates received for our rigs also began to fall. We expect that in the near term our customers will continue a cautious approach to exploration and development spending until prices again begin to rise. As a result, the future extent of the demand for our drilling services is uncertain.

COMPETITION

All of our lines of business 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 extremely 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 are more experienced in the exploration for and production of oil and natural gas than we are.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Our subsidiary, Unit Petroleum Company, serves as the general partner of five oil and gas limited partnerships and 13 employee oil and gas limited partnerships. Each year we form an employee partnership which acquires an interest, ranging from 2.5% to 15% of our interest, in most of the oil and natural gas wells we drill or acquire for our own account during that particular year. The limited partners in the employee partnerships are either employees or directors of Unit or its subsidiaries. One of the companies we acquired, Questa Oil and Gas Co., also served as the general partner of five private limited partnerships. We repurchased the limited partners' interest in three of the five Questa partnerships in the fourth quarter of 2000 and three of the partnerships were dissolved. In the first quarter of 2001, we purchased additional interests in the remaining two Questa partnerships and subsequently dissolved one of those partnerships.

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 done 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.

EMPLOYEES

As of February 20, 2002, we had approximately 949 employees in our land contract drilling operations, 58 employees in our oil and natural gas operations and 51 in our general corporate area. None of our employees are represented by 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 subject to these and 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, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract 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 all of 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 delivery crews and the delivery of equipment.

The 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 are depleted, 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 oil and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through our oil and natural gas operations. However, it is possible that we may not be able to continue to replace reserves from such activities. Low prices of oil and natural gas may further 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

The production and sale of oil and natural gas is highly affected by various state and federal regulations. 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 was 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 being 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 was not affected by the Decontrol Act.

Our sales of natural gas are 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 were 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 was required to be divested 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 are now required to 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. It remains to be seen 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 is 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 can be 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 frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with those laws.

SAFE HARBOR STATEMENT OF FURTHER ACTIVITY

Statements in this document 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 "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included in this document which address activities, events or developments which we expect or 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 also intended to identify forward-looking statements. These forward-looking statements include, among others, such things as:

- our year 2002 plans;
- the amount and nature of our future capital expenditures;
- the number of wells we intend to drill or rework;
- demand for our oil and natural gas and the price we will be paid for such production;
- our oil and natural gas prospects;
- estimates of our proved oil and natural gas reserves;
- reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of our oil and natural gas reserves;
- expansion and growth of our business and operations; and
- the use of our drilling rig services and what we will be paid for such services.

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

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 2002 and beyond to differ materially from those that may be set forth 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 the amount of our revenues, our profitability and the amount of 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 to be received for such natural gas); 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 that may be based 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 2001 production, a $.10 per Mcf change in what we are paid for our natural production would result in a corresponding $146,000 per month ($1,752,000 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $33,000 per month ($396,000 annualized) change in our pre-tax cash flow. During 2001, 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.

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 a project to be abandoned 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 should not be considered as 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 based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by the following factors:

. the amount and timing of actual 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, which is required by the SEC to be used 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 the ceiling is exceeded, even if prices were 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 our growth in 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. As a result of our working capital requirements, we currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2001, our long-term debt outstanding was $31.0 million. As of December 31, 2001, we had a total loan commitment of $100 million, but we elected to limit the amount available for borrowing under our bank loan agreement to $60 million to reduce cost. The amount outstanding under our bank loan agreement at December 31, 2001 was $30.0 million.

Our level of debt, the cash flow needed to satisfy our indebtedness and the covenants governing our indebtedness 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 its future debt is, to a large extent, a function of the costs associated with the projects undertaken by us at any given time and the cash flow received by us. Generally, the costs incurred by us in our normal operations 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, for many of the reasons mentioned above, our cash flow may not be sufficient to cover our current cash requirements which would then require us to increase our debt either through bank borrowings or otherwise.

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 2001.

PART II

Item 5. *Market for the Registrant's Common Equity and Related Stockholder Matters*

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:

	2000		2001	
QUARTER	**High**	**Low**	**High**	**Low**
First	$ 11.5000	$ 6.6250	$ 21.3750	$ 16.3000
Second	$ 14.5625	$ 9.0000	$ 23.0000	$ 14.5000
Third	$ 16.2500	$ 11.8125	$ 15.8000	$ 7.4100
Fourth	$ 19.4375	$ 12.3750	$ 14.2400	$ 8.2900

On February 20, 2002, there were 1,985 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 percent of our preceding year’s consolidated net income and then only if our working capital provided from operations for the previous year was equal to or greater than 175 percent of the current maturities of our long-term debt at the end of the previous year.

Item 6. *Selected Financial Data*

	Year Ended December 31,				
	1997 (1)	1998 (1)	1999 (1)	2000	2001
	(In thousands except per share amounts)				
Revenues	$ 96,478	$ 97,274	$ 102,352	$ 201,264	$ 259,179
Net Income	$ 12,330	$ 1,428	$ 3,048	$ 34,344	$ 62,766
Earnings Per Common Share:					
Basic	$ .47	$ .05	$ .10	$ .96	$ 1.75
Diluted	$ .46	$ .05	$ .10	$ .95	$ 1.73
Total Assets	$ 213,416	$ 233,096	$ 295,567	$ 346,288	$ 417,253
Long-Term Debt	$ 55,480	$ 75,048	$ 67,239	$ 54,000	$ 31,000
Other Long-Term Liabilities	$ 2,363	$ 2,368	$ 2,325	$ 3,597	$ 4,110
Cash Dividends Per Common Share	$ -	$ -	$ -	$ -	$ -

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

See Management's Discussion of Financial Condition and Results of Operations for a review of 1999, 2000 and 2001 activity.

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

FINANCIAL CONDITION AND LIQUIDITY

Our financial condition and liquidity, for current operations, depends on our cash flow from operating activities 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. Our loan agreement provides for a revolving credit facility, which terminates on May 1, 2005 followed by a three-year term loan. At December 31, 2001, we had borrowed $30.0 million, which was 50 percent of the amount available, as elected by us on October 1, 2001, and represented 30 percent of the loan value of our assets as determined by our banks on October 1, 2001. Most of our capital expenditures are discretionary and directed toward future growth.

Our Oil and Natural Gas Operations. Natural gas comprises approximately 90 percent of our total oil and natural gas reserves. Any appreciable change in natural gas prices has a significant affect on our revenues, cash flow and the value of our oil and natural gas reserves. Such price changes also influence the demand for our natural gas production, our drilling rigs (since they are used mainly to drill natural gas wells) and the amount we can charge for our contract drilling services.

Based on our 2001 production, a $.10 per Mcf change in what we are paid for our natural production would result in a corresponding $146,000 per month ($1,752,000 annualized) change in our pre-tax cash flow. Our 2001 average natural gas price declined from a high of $9.35 per Mcf in January to $2.05 per Mcf in September (an 78 percent decrease) before recovering to $2.16 per Mcf in December. For the year, our average natural gas price was $4.00 per Mcf. A $1.00 per barrel change in our oil price would have a $33,000 per month ($396,000 annualized) change in our pre-tax cash flow. We received the highest average oil price for the year during February at $28.13 per barrel. For the balance of the year oil prices declined resulting in our lowest average oil price of $16.28 per barrel in December. Our average oil price for the year was $23.62 per barrel.

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.

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 reduction of the carrying value of our oil and natural gas properties. Likewise, 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.

Hedging Activities. 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 fluctuations have on our cash flow. In the first quarter of 2000, we entered into swap transactions to lock in a portion of our oil production at higher oil prices. These transactions applied to approximately 50 percent of our daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our daily oil production for August and September of 2000 at prices ranging from $24.42 to $27.01. We entered into a collar contract covering approximately 25 percent of our daily oil production from November 1, 2000 through February 28, 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During 2000, the net effect of our oil hedging transactions for oil reduced our oil revenues by $465,000. We did not have any hedging transactions for natural gas in 2000. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

We entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 natural gas production at a floor price of $4.50 and a ceiling price of $5.95. We also entered into two natural gas collar contracts for approximately 38 percent of our 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. For the year our natural gas collar contracts added $2,030,000 to our natural gas revenues. We did not have any hedging transactions outstanding at December 31, 2001 nor on February 20, 2002.

Contract Drilling Operations. Our drilling operations are subject to many factors that influence the number of rigs we have working at any one time 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, the availability of labor to operate our rigs and our ability to supply the type of equipment required. We have not encountered major difficulty in hiring and retaining rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs was to increase rapidly in the future, shortages of experienced personnel would limit our ability to increase the number of rigs we could operate.

Low oil and natural gas prices during most of the 1980’s and 1990’s reduced demand for domestic land contract drilling rigs. However, in the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a substantial increase in demand for our rigs. Our average utilization of 44.6 rigs (95 percent) in January 2001 increased to 51.9 rigs (96 percent) in July before dropping to 33.5 rigs (62 percent) in December 2001. Our average utilization for the year was 46.3 rigs (90 percent).

As demand for our rigs increased during the year so did the dayrates we received. Our average dayrate in January was $8,176 and by September it had increased to $11,142. However, as demand began to decrease so did our rates and by December our average dayrate was $9,594. That rate has continued to fall into the first quarter of 2002. Based on the average utilization rate we achieved in 2001, a $100 per day change in dayrates has a $4,630 per day ($1,690,000 annualized) change in our pre-tax operating cash flow.

We anticipate that for the first half of 2002 the number of our rigs operating will range in the mid to high thirties and dayrates will continue to decline early in the first quarter before stabilizing. Utilization and dayrates for the last half of 2002 and beyond will depend mainly on the price of natural gas during the first half of 2002 and beyond. Even if demand increases in 2002, we anticipate that competition will continue to influence our operations.

Bank Loan Agreement. On July 24, 2001, we signed a $100 million bank loan agreement. At our election the amount currently available for us to borrow is set at $60 million. Although the current value of our assets would have allowed us to have access to the full $100 million, we elected to set the loan commitment at $60 million in order to reduce financing costs since we are charged a facility fee of .375 of 1 percent on the amount available but not borrowed.

Each year on April 1 and October 1 our banks redetermine the loan value of our assets. This value is primarily determined to be an amount equal to a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, is added to the loan value. Our loan agreement provides for a revolving credit facility which terminates on May 1, 2005 followed by a three-year term loan. Borrowing under our loan agreement totaled $30.0 million at December 31, 2001 and $28.0 million on February 20, 2002.

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

The interest rate on our bank debt was 3.3 percent at December 31, 2001 and 3.0 percent on February 20, 2002. At our election, any portion of our outstanding bank debt may be fixed at the Libor Rate, as adjusted depending on the level of our debt as a percentage of the amount available for us to borrow. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the remainder of our bank debt being subject to the Prime Rate. During any Libor Rate funding period, we may not pay any part of the outstanding principal balance which is subject to the Libor Rate. Borrowings subject to the Libor Rate were $28.0 million at December 31, 2001 and February 20, 2002.

The loan agreement requires us to maintain consolidated net worth of at least $125 million, a current ratio of not less than 1 to 1, a ratio of long-term debt, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.2 to 1 and a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1. In addition, working capital provided by our operations, as defined in the loan agreement, cannot be less than $40 million in any year. We are prohibited from paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of our consolidated net income from the preceding fiscal year and we can pay dividends only if working capital provided from our operations during the preceding year is equal to or greater than 175 percent of current maturities of long-term debt at the end of the preceding year. We also cannot incur additional debt except in certain 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 is prohibited unless it is in favor of our banks.

Shareholders' Equity, Working Capital and Capital Expenditures. Our shareholders’ equity at December 31, 2001 was $279.2 million giving us a ratio of long-term debt-to-total capitalization of 10 percent. Net cash provided by operations in 2001 was $133.0 million compared to $67.4 million in 2000. We had working capital of $17.6 million at December 31, 2001. Our total 2001 capital expenditures were $108.8 million ($400,000 net in accounts payable), of which $56.9 million was spent on our oil and natural gas operations, $51.3 million was spent on our drilling segment and $539,000 was spent primarily on furniture and fixtures and leasehold improvements.

Additional Oil and Gas Information. Our decisions on whether we try to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or anticipated market conditions, potential return on investment, future drilling potential and the availability of opportunities to obtain financing under the circumstances involved, all of which tend to provide us with a large degree of flexibility in determining when and if to incur such costs. As a result of the high natural gas prices during the last half of 2000 and into the first half of 2001, there were not many opportunities during 2001 to acquire producing properties at prices we consider attractive. As a result we spent $48.0 million on exploration and development drilling, $7.5 million for undeveloped leasehold and only $1.4 million for producing property acquisitions. We drilled 125 wells in 2001 as compared with 101 wells in 2000. Based on current prices, for 2002, we plan to drill an estimated 140 wells and have total capital expenditures of approximately $65 million for exploration, development drilling and acquisition of oil and natural gas properties.

On March 20, 2000, we completed the acquisition, by merger, of Questa Oil and Gas Co.("Questa") under which Questa became a wholly owned subsidiary of Unit Corporation. In the merger, each of Questa's outstanding shares of common stock (excluding treasury shares) was converted into .95 shares of our common stock. We issued approximately 1.8 million shares as a result of this merger. The merger was accounted for as a pooling of interests and, accordingly, all amounts prior to the merger were restated, unless otherwise noted, as if the companies had been combined during the periods presented.

Additional Drilling Information. While natural gas prices were high in early 2001, we continued to add to our rig fleet. In January 2001, we purchased a 750 horse power diesel electric rig with a 13,000 foot depth capacity for $3.2 million. This rig was working in our Gulf Coast region at December 31, 2001. In February 2001, we purchased a 1,000 horse power, winterized mechanical rig, with a 16,000 foot depth capacity, for $2.5 million. This rig was under contract in our Rocky Mountain region on December 31, 2001. In May we acquired two diesel electric rigs with depth capacities of 16,000 and 20,000 feet, for $7.8 million. These two rigs are both working in our Gulf Coast region. We also acquired a 16,000 foot depth capacity diesel electric rig. This rig will, depending on industry conditions and additional capital requirements, be placed in service when conditions warrant. The addition of these five rigs brings our fleet to 55, 54 of which are currently capable of operating. During 2001, we spent $38.7 million for new drilling rigs, drilling rig components and refurbishments of existing rigs, $11.6 million for new drill pipe and collars and $1.0 million for transportation equipment. For 2002 we anticipate that we will spend approximately $20 million on our drilling operations.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts that we are in with unrelated parties. The profit received by our contract drilling segment of $179,000 and $2,259,000 in 2000 and 2001, respectively, for this work was used to reduce the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Contractual Commitments. We have various contractual obligations at December 31, 2001, which are as follows:

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)	$ 30,000	$ -	$ -	$ 15,833	$14,167
Hickman Note(2)	2,000	1,000	1,000	-	-
Retirement Agreement(3)	1,330	20	470	600	240
Gas Purchaser Prepayment(4)	437	437	-	-	-
Operating Leases(5)	2,306	654	1,296	344	12
Total Contractual Obligations	$ 36,073	$2,111	$ 2,766	$ 16,777	$14,419

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(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt.

(2) On November 20, 1997, we acquired Hickman Drilling Company pursuant to an agreement and plan of merger entered into by and between us, Hickman Drilling Company and all of the holders of the outstanding capital stock of Hickman Drilling Company. As part of this acquisition, the former shareholders of Hickman held, as of December 31, 2001, promissory notes in the aggregate outstanding principal amount of $2.0 million (See Note 4 of our Consolidated Financial Statements). These notes are payable in equal annual installments on January 2, 2002 and January 2, 2003. The notes bear interest at the Chase Prime Rate, which at December 31, 2001 and February 20, 2002 was 4.75 percent. At February 20, 2002 the promissory notes outstanding totaled $1.0 million.

(3) 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 $25,000 monthly payments starting in July 2003 and continuing through June 2009 (See Note 4 of our

Consolidated Financial Statements).

(4) Due to a settlement agreement, which terminated at December 31, 1997, we have a liability of $437,000 at December 31, 2001, included in current portion of long-term debt on our Consolidated Balance Sheet, representing proceeds received from a natural gas purchaser as prepayment for natural gas. The $437,000 is payable on June 1, 2002.

(5) We lease office space in Tulsa, Houston and Woodward under the terms of operating leases expiring through January 31, 2007 (See Note 9 of our Consolidated Financial Statements).

At December 31, 2001, we also have the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	Total Amount Committed Or Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred Compensation Agreement(1)	$ 1,277	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 1,959	$ 436	Unknown	Unknown	Unknown
Repurchase Obligations(3)	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 (See Note 6 of our Consolidated Financial Statements).

(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 (See Note 6 of our Consolidated Financial Statements).

(3) 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 2002, 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 each 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 percent of the units outstanding. We made repurchases of $10,000 and $14,000 in 1999 and 2000, respectively, for such limited partners’ interests. No repurchases were made in 2001 (See Note 9 of our Consolidated Financial Statements).

Oil and Natural Gas Limited Partnerships. We are the general partner for eighteen oil and natural gas partnerships which were formed privately and publicly. The partnership’s revenues and costs are shared in accordance with formulas prescribed in each limited partnership agreement. The partnerships reimburse us for contract drilling, well supervision and general and administrative expense reimbursements. 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 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 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. During the 1999, 2000 and 2001, the total paid to us for all of these fees was $694,000, $966,000 and $1,107,000, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

At December 31, 2001, we owned a 40 percent equity interest in a natural gas gathering and processing company. Our balance sheet investment and equity in the company totaled $1.6 million at December 31, 2001. At December 31, 2001 and February 20, 2002, we were not guaranteeing any indebtedness of the gas gathering and processing company.

At December 31, 2001, one of our subsidiaries owned 4,949,500 shares of common stock and 1,800,000 warrants of Shenandoah Resources Ltd., a Canadian oil and natural gas exploration and production company. The investment of $346,000 is part of other assets in our consolidated balance sheet and was written down by $2.1 million during 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 percent discount rate) of estimated future net revenues from proved reserves, based on period-ending oil and natural gas prices, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized less related income tax. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts stockholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods.

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 substantial 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 probability of a ceiling test write-down. Based on oil and natural gas prices in effect on December 31, 2001 ($2.51 per Mcf for natural gas and $17.71 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 pricing has been erratic since year-end and any significant declines below year-end prices used in the reserve evaluation would likely result in a ceiling test write-down in subsequent quarterly reporting periods.

The value of our oil and natural gas reserves is used to determine the loan value under our loan agreement. This value is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimate of oil and natural gas reserves require extensive judgments of our reservoir engineering data and are generally 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 utilizes Ryder Scott Company, independent petroleum consultants, to review our reserves as prepared by our reservoir engineers.

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 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.

Under “footage” and “turnkey” contracts, we bear the risk of completion of the well, so revenues and expenses are recognized using the completed contract method. The entire amount of a loss, if any, is recorded when the loss can be determined. 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

In the 18 years prior to the last half of 1999, the effects of inflation on our operations was minimal due to low inflation rates and moderate demand for contract drilling services. However, starting in the last half of 1999 and throughout 2000 and the first three quarters of 2001, as drilling rig dayrates and utilization increased, the impact of inflation increased as the availability of used equipment and third party services decreased. Due to industry-wide demand for qualified labor, contract drilling labor costs increased substantially in the summer of 2000 and once again in the summer of 2001. 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. If industry activity recovers and returns to levels achieved in early 2001, 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.

NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2001, we 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, we are 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. We periodically enter into derivative commodity instruments to hedge our 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. At December 31, 2001, we were not holding any natural gas or oil derivative contracts.

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 already recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. We expensed $243,000 annually for the amortization of goodwill, and the unamortized balance of goodwill is $5,088,000 at December 31, 2001. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for us). We do not believe the future impact from the adoption of FAS 142 on our financial position or results of operation will be material.

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002 (January 1, 2003 for us) and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled). We have not yet determined the effect of the adoption of FAS 143 on our financial position or results of operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144). FAS 144 is effective for fiscal years beginning after

December 15, 2001 (January 1, 2002 for us). This statement supersedes Statement of Financial Accounting Standards No. 121 “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of” and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. We do not believe the future impact from the adoption of FAS 144 on our financial position or results of operations will be material.

RESULTS OF OPERATIONS

2001 versus 2000

Net income for 2001 was $62,766,000, compared with $34,344,000 for 2000. This increase was due to increases in the use of our drilling rigs, as well as, the dayrates we received for the use of the drilling rigs. High natural gas prices in the last quarter of 2000 and the first quarter of 2001 increased the demand for our drilling rigs which in turn pushed contract drilling dayrates higher.

Our oil and natural gas revenues decreased 2 percent in 2001 when compared with 2000. The average natural gas prices we received in 2001 increased 2 percent, but this increase was offset by a 2 percent reduction in our natural gas production. The average oil price we received dropped 12 percent while oil production increased one percent between the comparative years. We drilled 125 gross wells (53.4 net wells) in 2001, compared to 101 gross wells (40.2 net wells) in 2000.

In 2001, revenues from our contract drilling operations increased by 55 percent as the average number of our drilling rigs being used increased from 39.8 in 2000 to 46.3 in 2001. Revenues per rig per day increased 33 percent between the comparative years. Daywork revenues represented 88 percent of our total drilling revenues in 2001 and 75 percent in 2000.

Operating margins (revenues less operating costs) for our oil and natural gas operations were 75 percent in 2001 and 79 percent in 2000. This decrease resulted mainly from declines in production on older wells without corresponding declines in operating expenses. Total operating cost increased 12 percent and was due mainly to the addition of new wells through development drilling and increases in ad valorem taxes, workover expenses and compression fees.

Our contract drilling operating margins increased from 22 percent in 2000 to 46 percent in 2001. The additional operating margin was generally due to additional revenue received per day and an increase in the number of rigs being used. Our contract drilling operating cost per rig per day decreased $400 in 2001 when compared with 2000 as increased usage reduced the impact of our fixed indirect drilling expenses. Total contract drilling operating costs were up 8 percent in 2001 versus 2000 primarily due to increased utilization and increases in field labor cost.

Contract drilling depreciation increased 16 percent due to higher rig utilization. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased 20 percent due primarily to a $2.1 million impairment of our investment in a company which has oil and natural gas properties located in Canada and from a 11 percent increase in the average DD&A rate per Mcfe to $0.91 in 2001 from $0.82 Mcfe in 2000.

General and administrative expenses increased 29 percent. 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. Interest expense decreased 45 percent as our average outstanding debt decreased 28 percent during 2001. The average interest rate decreased from 7.9 percent in 2000 to 5.7 percent in 2001.

2000 versus 1999

Net income for 2000 was $34,344,000, compared with $3,048,000 for 1999. This improvement was mainly due to increases in our natural gas and oil prices and production volumes. Higher oil and natural gas prices also elevated the demand for our drilling rigs, resulting in increased utilization of our rigs, dayrates and net income.

Our oil and natural gas revenues increased 99 percent in 2000 due to a 91 percent and 54 percent rise in the average prices we received for natural gas and oil, respectively. For the year, natural gas production increased by 11 percent and oil production increased by 15 percent when compared to 1999. Production grew as we drilled 101 gross wells (40.2 net wells) in 2000 compared to 51 gross wells (21.4 net wells) in 1999. Natural gas production for the fourth quarter of 2000 exceeded 1999's fourth quarter production by 11 percent.

In 2000, revenues from our contract drilling operations increased by 95 percent as the average number of our drilling rigs being used increased from 23.1 in 1999 to 39.8 in 2000. Revenues per rig per day increased 13 percent between the comparative years. The acquisition of the Parker drilling rigs added 6.5 rigs to our utilization rate in the fourth quarter of 1999 and 9.0 rigs to our 2000 utilization at dayrates substantially higher than those achieved in our other marketing area. Our rigs, excluding those acquired from Parker, added 9.3 rigs to utilization and added an additional 10 percent to their revenue per rig per day. Daywork revenues represented 75 percent of our total drilling revenues in 2000 and 61 percent in 1999.

Operating margins (revenues less operating costs) for our oil and natural gas operations were 79 percent in 2000 and 67 percent in 1999. This increase resulted primarily from the increase in the average oil and natural gas prices we received. Total operating costs between the comparative years increased 31 percent due primarily to the 113 percent increase in production taxes incurred as a result of higher revenues and to a lesser extent from the addition of new wells through development drilling.

Our contract drilling operating margins increased from 14 percent in

1999 to 22 percent in 2000. The additional operating margin was generally due to additional revenue received per day and an increase in the number of rigs utilized. Our contract drilling operating cost per rig day increased $109 in 2000 as total contract drilling operating costs were up 76 percent in 2000 versus 1999 primarily due to increased utilization.

Contract drilling depreciation increased 75 percent due to the impact of higher depreciation per operating day associated with the newly acquired Parker rigs and an overall increase in our rig utilization. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased 8 percent due to additional production volumes. The average DD&A rate per Mcfe decreased 4 percent to $0.82 in 2000.

General and administrative expenses increased 14 percent as certain employee costs, outside contract services and office expenses increased due to the growth in both of our operating segments. Interest expense decreased 3 percent as our average outstanding debt decreased 14 percent during 2000. The average interest rate increased from 7.0 percent in 1999 to 7.9 percent in 2000.

On May 3, 1999, our contract drilling office in Moore, Oklahoma was struck by a tornado destroying two buildings and damaging various vehicles and drilling equipment. In May 1999, we received $500,000 of insurance proceeds for the destroyed buildings, and, as a result, in the second quarter of 1999, we recognized a gain of $315,000 recorded as part of other revenues. During the first quarter of 2000, we received the final insurance proceeds totaling $987,000 for the contents of the destroyed buildings, damaged equipment and clean up costs. From these proceeds, we recognized a gain of $599,000 recorded as part of other revenues in the first quarter of 2000.

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 have received for our oil and natural gas production have been volatile and such volatility 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 2001 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $146,000 per month ($1,752,000 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $33,000 per month ($396,000 annualized) change in our pre-tax cash flow.

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 fluctuations have on our cash flow. In the first quarter of 2000, we entered into swap transactions to lock in a portion of our oil production at higher oil prices. These transactions applied to approximately 50 percent of our daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our daily oil production for August and September of 2000 at prices ranging from $24.42 to $27.01. We entered into a collar contract covering approximately 25 percent of our daily oil production from November 1, 2000 through February 28, 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During 2000, the net effect of our oil hedging transactions for oil reduced our oil revenues by $465,000. We did not have any hedging transactions for natural gas in 2000. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

We entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 natural gas production at a floor price of $4.50 and a ceiling price of $5.95. We also entered into two natural gas collar contracts for approximately 38 percent of our 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. For the year our natural gas collar contracts added $2,030,000 to our natural gas revenues. We did not have any hedging transactions outstanding at December 31, 2001 nor on February 20, 2002.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the prime rate or the London Interbank Offered Rate (“Libor Rate”). At our election, borrowings under our revolving credit and term loan may be fixed at the Libor 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 such financial instruments in the future should our assessment of future interest rates warrant such use. Based on our average outstanding long-term debt in 2001, a one percent change in the floating rate would change our annual cash flow before income taxes by approximately $450,000.

Item 8. *Financial Statements and Supplementary Data*

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2000	2001
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 726	$ 391
Accounts receivable (less allowance for doubtful accounts of $919 and $604)	40,220	33,886
Materials and supplies	3,802	5,358
Income tax receivable	-	3,198
Prepaid expenses and other	1,269	3,761
Total current assets	46,017	46,594
Property and Equipment:		
Drilling equipment	196,736	244,698
Oil and natural gas properties, on the full cost method	349,707	406,491
Transportation equipment	5,803	6,441
Other	8,801	9,231
	561,047	666,861
Less accumulated depreciation, depletion, amortization and impairment	270,690	304,643
Net property and equipment	290,357	362,218
Other Assets	9,914	8,441
Total Assets	$ 346,288	$ 417,253

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS – CONTINUED

	As of December 31, 2000	As of December 31, 2001
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities	$ 1,627	$ 1,893
Accounts payable	21,012	16,292
Accrued liabilities	9,854	10,616
Contract advances	179	240
Total current liabilities	32,672	29,041
Long-Term Debt	54,000	31,000
Other Long-Term Liabilities (Note 4)	3,597	4,110
Deferred Income Taxes	41,479	73,940
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, 35,768,344 and 36,006,267 shares issued, respectively	7,154	7,201
Capital in excess of par value	139,872	141,977
Retained earnings	67,514	130,280
Treasury stock at cost (30,000 shares)	-	(296)
Total shareholders' equity	214,540	279,162
Total Liabilities and Shareholders' Equity	$ 346,288	$ 417,253

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	1999	**2000**	**2001**
	(Restated, See Note 2)		
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 55,479	$ 108,075	$ 167,042
Oil and natural gas	46,225	92,016	90,237
Other	648	1,173	1,900
Total revenues	102,352	201,264	259,179
Expenses:			
Contract drilling:			
Operating costs	47,721	84,051	91,006
Depreciation	6,851	11,999	13,888
Oil and natural gas:			
Operating costs	15,084	19,754	22,196
Depreciation, depletion, amortization and impairment	17,114	18,492	22,116
General and administrative	5,750	6,560	8,476
Interest	5,268	5,136	2,818
Total expenses	97,788	145,992	160,500
Income Before Income Taxes	4,564	55,272	98,679
Income Tax Expense:			
Current	29	621	5,609
Deferred	1,487	20,307	30,304
Total income taxes	1,516	20,928	35,913
Net Income	$ 3,048	$ 34,344	$ 62,766
Net Income Per Common Share:			
Basic	$ .10	$ .96	$ 1.75
Diluted	$ .10	$ .95	$ 1.73

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, 1999, 2000 and 2001
(1999 Restated, See Note 2)

	Common Stock	Capital In Excess Of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
			(In thousands)			
Balances, January 1, 1999	$ 5,478	$ 81,915	$ 30,122	$ -	$ (131)	$ 117,384
Net income	-	-	3,048	-	-	3,048
Activity in employee compensation plans (252,511 shares)	50	680	-	-	131	861
Sale of common stock (7,000,000 shares)	1,400	48,682	-	-	-	50,082
Issuance of stock for acquisition (1,000,000 shares)	200	7,938	-	-	-	8,138
Questa purchase of treasury shares	-	(8)	-	-	-	(8
Balances, December 31, 1999	7,128	139,207	33,170	-	-	179,505
Net income	-	-	34,344	-	-	34,344
Activity in employee compensation plans (135,419 shares)	26	665	-	-	-	691
Balances, December 31, 2000	$ 7,154	$ 139,872	$ 67,514	$ -	$ -	$ 214,540

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY - CONTINUED
Year Ended December 31, 1999, 2000 and 2001
(1999 Restated, See Note 2)

	Common Stock	Capital In Excess Of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
			(In thousands)			
Balances, December 31, 2000	$ 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):						
Change in value of cash flow derivative instruments used as cash flow hedges	-	-	-	1,258	-	1,258
Adjustments reclasifica- tion - 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 consolidated financial statements

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999 (Restated, See Note 2)	2000	2001
	(In thousands)		
Cash Flows From Operating Activities:			
Net Income	$ 3,048	$ 34,344	$ 62,766
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	24,285	30,946	36,642
Equity in net earnings of unconsolidated subsidiary	-	-	(1,148)
Loss (gain) on disposition of assets	(400)	(969)	(56)
Employee stock compensation plans	436	443	2,873
Bad debt expense	255	350	-
Deferred tax expense	1,487	20,307	30,304
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(8,450)	(18,500)	6,334
Materials and supplies	49	(543)	(1,556)
Prepaid expenses and other	140	(96)	(3,533)
Accounts payable	2,667	(1,370)	(155)
Accrued liabilities	1,590	3,067	929
Contract advances	48	(179)	61
Other liabilities	(442)	(440)	(440)
Net cash provided by operating activities	24,713	67,360	133,021

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,		
	1999 (Restated, See Note 2)	2000	2001
	(In thousands)		
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions)	$ (69,503)	$ (60,447)	$(108,339)
Proceeds from disposition of property and equipment	1,438	4,259	2,631
(Acquisition) disposition of other assets	91	(2,656)	17
Net cash used in investing activities	(67,974)	(58,844)	(105,691)
Cash Flows From Financing Activities:			
Borrowings under line of credit	61,600	31,200	57,200
Payments under line of credit	(68,400)	(44,439)	(79,200)
Net payments on notes payable and other long-term debt	(1,090)	(556)	(1,000)
Proceeds from sale of common stock	50,136	250	609
Book overdrafts (Note 1)	2,974	3,108	(4,978)
Acquisition of treasury stock	-	-	(296)
Net cash provided by (used in) financing activities	45,220	(10,437)	(27,665)
Net Increase (Decrease) in Cash and Cash Equivalents	1,959	(1,921)	(335)
Cash and Cash Equivalents, Beginning of Year	688	2,647	726
Cash and Cash Equivalents, End of Year	$ 2,647	$ 726	$ 391
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest	$ 5,850	$ 5,135	$ 2,807
Income taxes	$ 30	$ 519	$ 7,779

See Note 2 for non-cash investing activities.

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Nature of Business. Unit is engaged in the land contract drilling of natural gas and oil wells and the exploration, development, acquisition and production of oil and natural gas properties. Unit's current contract drilling operations are focused primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and the Rocky Mountain regions. Unit's primary exploration and production operations are also conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of its contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2001, Unit had an interest in a total of 3,038 wells and served as operator of 688 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 2001, 54 of Unit's 55 rigs performed contract drilling services.

Drilling Contracts. Unit recognizes revenues generated from "daywork" drilling contracts as the services are performed, which is similar to the percentage of completion method. Under "footage" and "turnkey" contracts, Unit bears the risk of completion of the well therefore, revenues and expenses are recognized using the completed contract method. 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, 2000 and 2001, book overdrafts of $6.1 million and $1.1 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 betterments 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 percent 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 over the fair value of the net assets acquired and has been amortized on the straight-line method using a 25 year life through December 31, 2001. 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 changed. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). We do not believe the future impact from the adoption of FAS 142 on our financial position or results of operation will be material. Net goodwill reported in other assets at December 31, 2000 and 2001 was $5,331,000 and $5,088,000, respectively with accumulated amortization at December 31, 2000 and 2001 of $750,000 and $993,000, respectively.

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 $0.85, $0.82 and $0.91 per Mcfe in 1999, 2000 and 2001, 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 $14.4 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 12, such estimates are imprecise. As part of the merger with Questa, the oil and gas properties of Questa were restated from the successful effort method of accounting to the full cost method of accounting used by Unit Corporation.

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

The SEC's full cost accounting rules prohibit recognition of income in current operations for services performed on oil and natural gas properties in which Unit has an interest or on properties in which a partnership, of which Unit is a general partner, has an interest. Accordingly, in 2000 and 2001, Unit recorded $179,000 and $2,259,000 of contract drilling profits, respectively, as a reduction of the carrying value of its oil and natural gas properties rather than including these profits in current operations. No contract drilling profits were realized on such interests in 1999.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in eighteen 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. Based upon the 2001 average natural gas price received of $3.89 per Mcf which excludes the effects of hedging, Unit estimates its balancing position to be approximately $6.4 million on under-produced properties and approximately $6.1 million on over-produced properties. 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.

Employee and Director Stock Based Compensation. Unit applies APB Opinion 25 in accounting for its stock option plans for its employees and directors. 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 1999, 2000 and 2001 no compensation expense has been recognized. As provided by Financial Accounting Standard No. 123 "Accounting for Stock-Based Compensation," Unit has disclosed the pro forma effects of recording compensation for such option grants based on fair value in Note 6 to the financial statements.

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 $4,462,000 and $4,583,000 for employer group health insurance and worker's compensation at December 31, 2000 and 2001, respectively. Due to high premium cost, Unit has decided to increase its deductible for general liability claims from $25,000 to $200,000.

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. At December 31, 2001, 30,000 shares had been repurchased for $296,000.

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 2001, one purchaser of Unit's oil and natural gas production accounted for approximately 15 percent of consolidated revenues. At December 31, 2001, accounts receivable from one oil and natural gas purchaser was approximately $2.1 million. In addition, at December 31, 2000 and 2001, Unit had a concentration of cash of $1.7 million and $2.0 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. In the first quarter of 2000, Unit entered into swap transactions in an effort to lock in a portion of its daily production at the higher oil prices which currently existed. These transactions applied to approximately 50 percent of Unit's daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our oil production for August and September of 2000, at prices ranging from $24.42 to $27.01. Unit entered into a collar contract for approximately 25 percent of its daily production for the period covering November 1, 2000 to February 28, 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 2000, the net effect of these hedging transactions yielded a reduction in Unit's oil revenues of $465,000. 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 percent 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 percent of its September thru 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. At December 31, 2001, Unit was not holding any natural gas or oil derivative contracts.

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 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 already in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. Unit expensed $243,000 annually for the amortization of goodwill, and the unamortized balance of goodwill is $5,088,000 at December 31, 2001. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Unit does not believe the future impact from the adoption of FAS 142 on our financial position or results of operations will be material.

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143, is effective for fiscal years beginning after June 15, 2002 (January 1, 2003 for Unit), and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for Unit’s depleted wells), in the period in which the liabilities are incurred (at the time the wells are drilled). Unit has not yet determined the effect of the adoption of FAS 143 on its financial position or results of operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, “Accounting for Impairment or Disposal of Long-Lived Assets” (FAS 144). FAS 144 is effective for fiscal years beginning after December 15, 2001 (January 1, 2002 for Unit). This statement supersedes Statement of Financial Accounting Standards No. 121 “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of” and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. Unit does do not believe the future impact from the adoption of FAS 144 on our financial position and results of operation will be material.

NOTE 2 – ACQUISITIONS

On March 20, 2000, Unit completed the acquisition, by merger, of Questa Oil and Gas Co.("Questa") under which Questa became a wholly owned subsidiary of Unit Corporation. In the merger each of Questa's outstanding shares of common stock (excluding treasury shares) was converted into .95 shares of our common stock. Unit issued approximately 1.8 million shares as a result of this merger. The merger has been accounted for as a pooling of interests and, accordingly, all amounts in the financial statements have been restated as if the companies had been combined throughout the periods presented.

The results of operations for each company and the combined amounts presented in Unit Corporation’s consolidated financial statements are as follows:

	Year Ended December 31, 1999	Three Months Ended March 31, 2000
	(In thousands)	
Revenues:		
Unit Corporation	$ 97,453	$ 35,807
Questa	4,899	1,420
Combined	$ 102,352	$ 37,227
Net Income:		
Unit Corporation	$ 1,486	$ 3,095
Questa	1,562	483
Combined	$ 3,048	$ 3,578

Questa’s net income has been increased by $527,000 in 1999 and increased by $12,000 in the first quarter of 2000 to restate Questa’s financial statements to the full cost method of accounting used by Unit.

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
For the Year Ended December 31, 1999:			
Basic earnings per common share	$ 3,048,000	29,639,000	$ 0.10
Effect of dilutive stock options		274,000	
Diluted earnings per common share	$ 3,048,000	29,913,000	$ 0.10
For the Year Ended December 31, 2000:			
Basic earnings per common share	$ 34,344,000	35,723,000	$ 0.96
Effect of dilutive stock options		409,000	
Diluted earnings per common share	$ 34,344,000	36,132,000	$ 0.95
For the Year Ended December 31, 2001:			
Basic earnings per common share	$ 62,766,000	35,967,000	$ 1.75
Effect of dilutive stock options		291,000	
Diluted earnings per common share	$ 62,766,000	36,258,000	$ 1.73

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,:

	1999	2000	2001
Options	196,500	144,000	153,000
Average exercise price	$ 8.49	$ 16.59	$ 16.79

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

Long-term debt consisted of the following as of December 31, 2000 and 2001:

	2000	2001
	(In thousands)	
Revolving credit and term loan, with interest at December 31, 2000 and 2001 of 7.8 percent and 3.3 percent, respectively	$ 52,000	$ 30,000
Notes payable for Hickman Drilling Company acquisition with interest at December 31, 2000 and 2001 of 9.5 percent and 4.75 percent, respectively	3,000	2,000
	55,000	32,000
Less current portion	1,000	1,000
Total long-term debt	$ 54,000	$ 31,000

At December 31, 2001, Unit has 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. Borrowings under the loan agreement are limited to a commitment amount. Although, the current value of Unit’s assets under the latest loan value computation supported a full $100 million, Unit elected to set the loan commitment at $60 million in order to reduce costs. The loan value under the revolving credit facility is subject to a semi-annual re-determination calculated primarily as 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 loan value. Any declines in commodity prices would adversely impact the determination of the loan value.

Borrowings under the revolving credit facility bear interest at the Chase Manhattan Bank, N.A. prime rate (“Prime Rate”) or the London Interbank Offered Rates (“Libor Rate”) plus 1.00 to 1.50 percent depending on the level of debt as a percentage of the total loan value. Subsequent to May 1, 2005, borrowings under the loan agreement bear interest at the Prime Rate or the Libor Rate plus 1.25 to 1.75 percent depending on the level of debt as a percentage of the total loan value.

At Unit’s election, any portion of the debt outstanding may be fixed at the Libor Rate for 30, 60, 90 or 180 days. During any Libor Rate funding period the outstanding principal balance of the note to which such Libor Rate option applies may not be paid. Borrowings under the Prime Rate option may be paid anytime in part or in whole without premium or penalty.

Unit paid an origination fee of $60,000 at inception of the loan agreement and a facility fee of 3/8 of one percent is charged for any unused portion of the commitment amount. Some of Unit’s drilling rigs are collateral for such indebtedness and the balance of Unit’s assets are subject to a negative pledge.

The loan agreement includes prohibitions against (i) the payment of dividends (other than stock dividends) during any fiscal year in excess of 25 percent of the consolidated net income of Unit during the preceding fiscal year, and only if working capital provided from operations during said year is equal to or greater than 175 percent of current maturities of long-term debt at the end of such year, (ii) the incurrence by Unit or any of its subsidiaries of additional debt with certain very limited exceptions and (iii) the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any property of Unit or any of its subsidiaries, except in favor of its banks. The loan agreement also requires that Unit maintain consolidated net worth of at least $125 million, a current ratio of not less than 1 to 1, a ratio of long-term debt, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.2 to 1 and a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1. In addition, working capital provided by operations, as defined in the loan agreement, cannot be less than $40 million in any year.

In November 1997, Unit completed the acquisition of Hickman Drilling Company. In association with this acquisition, we issued an aggregate of $5.0 million in promissory notes payable in five equal annual installments commencing January 2, 1999, with interest at the Prime Rate.

Other long-term liabilities consisted of the following as of December 31, 2000 and 2001:

	2000	2001
	(In thousands)	
Natural gas purchaser prepayment	$ 877	$ 437
Separation benefit plan	1,811	1,959
Deferred compensation plan	1,536	1,277
Retirement agreement	-	1,330
	4,224	5,003
Less current portion	627	893
Total other long-term liabilities	$ 3,597	$ 4,110

At December 31, 2001, Unit has a prepayment balance of $437,000 representing proceeds received from a purchaser for prepayment of natural gas under a natural gas settlement agreement, which terminated on December 31, 1997. This amount is net of natural gas recouped and net of certain amounts disbursed to other owners for their proportionate share of the prepayments. At termination, the December 31, 1997 prepayment balance of $2.2 million became payable in equal annual payments over a five year period. The final payment of $437,000 is due on June 1, 2002.

Unit has other long-term liabilities of $4,110,000, consisting of $1,523,000 accrued in connection with its separation benefit plans, $1,277,000 accrued in connection with its Deferred Compensation Plan and $1,310,000 for the present value of a separation agreement, made in the second quarter of 2001, in connection with the retirement of King Kirchner from his position as Chief Executive Officer.

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities from 2002 through 2006 are $1,893,000, $1,170,000, $300,000, $6,133,000 and $10,300,000. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2001 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:

	1999	2000	2001
	(In thousands)		
Income tax expense computed by applying the statutory rate	$ 1,552	$ 19,345	$ 34,538
State income tax, net of federal benefit	139	1,575	2,859
Goodwill and other	(175)	8	(1,484)
Income tax expense	$ 1,516	$ 20,928	$ 35,913

Deferred tax assets and liabilities are comprised of the following at December 31, 2000 and 2001:

	2000	2001
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 3,308	$ 3,867
Net operating loss carryforward	15,027	-
Statutory depletion carryforward	2,260	2,874
Alternative minimum tax credit carryforward	1,123	5,196
Gross deferred tax assets	21,718	11,937
Deferred tax liability:		
Depreciation, depletion and amortization	(63,197)	(83,720)
Net deferred tax liability	(41,479)	(71,783)
Current deferred tax asset	-	2,157
Non-current - deferred tax liability	$ (41,479)	$ (73,940)

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, 2001, Unit has an excess statutory depletion carryforward of approximately $7,562,000, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations.

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. On January 4, 1999, 87,376 shares of common stock were issued for payment of Unit's 1998 year-end bonuses. No shares were issued under the Plan in 2000 and 2001.

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 become exercisable at the rate of 20 percent per year one year after being granted and expire after ten 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, 1999	769,360	$ 4.19
Exercised	(109,760)	2.76
Cancelled	(2,000)	10.00
Outstanding at December 31, 1999	657,600	4.41
Granted	146,000	16.59
Exercised	(79,700)	4.19
Cancelled	(4,200)	4.94
Outstanding at December 31, 2000	719,700	6.87
Exercised	(177,200)	3.13
Cancelled	(10,400)	10.26
Outstanding at December 31, 2001	532,100	$ 8.09

	OUTSTANDING OPTIONS AT DECEMBER 31, 2001		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.75 - $ 3.75	270,500	5.3 years	$ 3.42
$ 7.25 - $16.69	261,600	7.2 years	$ 12.92

EXERCISE PRICES	EXERCISABLE OPTIONS AT DECEMBER 31, 2001 NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.75 - $ 3.75	189,500	$ 3.27
$ 7.25 - $16.69	139,800	$ 10.28

Options for 414,200, 407,900 and 329,300 shares were exercisable with weighted average exercise prices of $3.96, $4.24 and $6.25 at December 31, 1999, 2000 and 2001, 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 ten 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, 1999	72,500	$ 5.74
Granted	12,500	6.90
Exercised	(5,000)	5.13
Cancelled	(2,500)	8.94
Outstanding at December 31, 1999	77,500	5.86
Granted	17,500	12.19
Outstanding at December 31, 2000	95,000	7.03
Granted	17,500	17.54
Exercised	(37,000)	6.80
Outstanding at December 31, 2001	75,500	$ 9.58

	OUTSTANDING AND EXERCISABLE OPTIONS AT DECEMBER 31, 2001		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 1.75 - $ 3.75	17,500	1.8 years	$ 3.16
$ 6.87 - $17.54	58,000	7.4 years	$ 11.51

Unit applies APB Opinion 25 in accounting for Unit's Stock Option Plan and Non-Employee Directors' Stock Option Plan. Accordingly, based on the nature of Unit's grants of options, no compensation cost has been recognized in 1999, 2000 and 2001. Had compensation been determined on the basis of fair value pursuant to FASB Statement No. 123, net income and earnings per share would have been reduced as follows:

	1999	2000	2001
Net Income (In thousands):			
As reported	$ 3,048	$ 34,344	$ 62,766
Pro forma	$ 2,652	$ 33,986	$ 61,822
Basic Earnings per Share:			
As reported	$ .10	$ .96	$ 1.75
Pro forma	$ .09	$ .95	$ 1.72
Diluted Earnings per Share:			
As reported	$ .10	$ .95	$ 1.73
Pro forma	$ .09	$ .94	$ 1.71

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 1999, 2000 and 2001 was 0.55, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 6.70, 5.26 and 5.41 percent in 1999, 2000 and 2001, respectively. 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 2000 under the Stock Option Plan were $1,470,000. No options were issued under the Stock Option Plan in 1999 and 2001. Under the Non-Employee Directors' Stock Option Plan the aggregate fair value of options granted during 1999, 2000 and 2001 were $58,000, $99,000 and $201,000, respectively.

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. The Company made discretionary contributions under the plan of 105,819, 58,353 and 35,016 shares of common stock and recognized expense of $464,000, $595,000 and $1,082,000 in 1999, 2000 and 2001, 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, 1999, 2000 and 2001 totaled $1,165,000, $1,536,000 and $1,277,000, 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 $502,000, $558,000 and $589,000 in 1999, 2000 and 2001, respectively, for benefits associated with anticipated payments from both separation plans.

We have entered into key employee change of control contracts with five of our 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 us. 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 by the company (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 formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2001, with a subsidiary of Unit serving as General Partner. Questa Oil and Gas Co. formed five private limited partnerships for 1981 to 1993. 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 Unit in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with Unit and Questa, respectively, in most drilling operations and most producing property acquisitions commenced by Unit or Questa for their own account during the period from the formation of the Partnerships through December 31 of each year. Unit repurchased the limited partner’s interest in three of five Questa partnerships in the fourth quarter of 2000 and one of the Questa partnerships in the first quarter of 2001 and the four partnerships were dissolved.

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

	1999	**2000**	**2001**
		(In thousands)	
Contract drilling	$ 94	$ 296	$ 416
Well supervision and other fees	$ 425	$ 478	$ 498
General and administrative expense reimbursement	$ 175	$ 192	$ 193

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, $9,000, $6,000 and $3,000 during the years ended December 31, 1999, 2000 and 2001, respectively, for purchases of natural gas production.

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 percent of its value.

The rights become exercisable 10 days after Unit learns that an acquiring person (as defined in the Plan) has acquired 15 percent 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 percent 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 tenth 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 under the terms of operating leases expiring through January 31, 2007. Future minimum rental payments under the terms of the leases are approximately $654,000, $648,000, $648,000, $193,000 and $151,000 in 2002, 2003, 2004, 2005 and 2006, respectively. Total rent expense incurred by the Company was $422,000, $535,000 and $582,000 in 1999, 2000 and 2001, 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 percent of the units outstanding. Unit made repurchases of $10,000 and $14,000 in 1999 and 2000, respectively, for such limited partners' interests. No repurchases were made in 2001. Subsequent to the merger, in 2000, Unit also paid $17,000 for additional interest in two of the Questa limited partnerships and $1,980,000 for all the remaining interest in three other Questa partnerships. In 2001, Unit paid $15,000 for interests in two of the

Questa limited partnerships and subsequently dissolved one of the Questa partnerships.

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

In 1998, Unit adopted Statement of Financial Accounting Standard No. 131, "Disclosures about Segments of an Enterprise and Related Information." Unit has two business segments: Contract Drilling and Oil and Natural Gas, representing its two strategic business units offering different products and services. The Contract Drilling segment provides land contract drilling of oil and natural gas wells and the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties.

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.

	1999	2000	2001
		(In thousands)	
Revenues:			
Contract drilling	$ 55,479	$ 108,075	$ 167,042
Oil and natural gas	46,225	92,016	90,237
Other	648	1,173	1,900
Total revenues	$ 102,352	$ 201,264	$ 259,179
Operating Income (1):			
Contract drilling	$ 907	$ 12,025	$ 62,148
Oil and natural gas	14,027	53,770	45,925
Total operating income	14,934	65,795	108,073
General and administrative			

expense	(5,750)	(6,560)	(8,476)
Interest expense	(5,268)	(5,136)	(2,818)
Other income (expense)- net	648	1,173	1,900
Income before income taxes	$ 4,564	$ 55,272	$ 98,679
Identifiable Assets (2):			
Contract drilling	$ 125,853	$ 141,324	$ 183,471
Oil and natural gas	164,252	198,251	220,476
Total identifiable assets	290,105	339,575	403,947
Corporate assets	5,462	6,713	13,306
Total assets	$ 295,567	$ 346,288	$ 417,253

	1999	2000	2001
	(In thousands)		
Capital Expenditures:			
Contract drilling	$ 55,656	$ 22,045	$ 51,280
Oil and natural gas	21,532	39,884	56,933
Other	744	3,324	539
Total capital expenditures	$ 77,932	$ 65,253	$ 108,752
Depreciation, Depletion, Amortization and Impairment:			
Contract drilling	$ 6,851	$ 11,999	$ 13,888
Oil and natural gas	17,114	18,492	22,116
Other	320	455	638
Total depreciation, depletion, amortization and impairment	$ 24,285	$ 30,946	$ 36,642

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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.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2000 and 2001 is as follows:

	THREE MONTHS ENDED			
	MARCH 31	**JUNE 30**	**SEPTEMBER 30**	**DECEMBER 31**
	(In thousands except per share amounts)			
Year Ended December 31, 2000:				
Revenues	$ 37,227	$ 43,587	$ 54,788	$ 65,662
Gross profit(1)	$ 7,719	$ 11,810	$ 18,154	$ 28,112
Income before income taxes	$ 5,648	$ 9,076	$ 15,622	$ 24,926
Net income	$ 3,578	$ 5,627	$ 9,685	$ 15,454
Earnings per common share:				
Basic	$ 0.10	$ 0.16	$ 0.27	$ 0.43
Diluted (2)	$ 0.10	$ 0.16	$ 0.27	$ 0.43
Year Ended December 31, 2001:				
Revenues	$ 70,443	$ 71,087	$ 68,399	$ 49,250
Gross profit(1)	$ 33,414	$ 32,091	$ 27,277	$ 15,291
Income before income taxes	$ 30,862	$ 29,070	$ 25,170	$ 13,577
Net income(3)	$ 19,172	$ 18,048	$ 15,631	$ 9,915
Earnings per common share:				
Basic (4)	$ 0.53	$ 0.50	$ 0.43	$ 0.28
Diluted	$ 0.53	$ 0.50	$ 0.43	$ 0.27

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

(2) 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.

(3) The net income for the three months ended December 31, 2001 includes a tax benefit of $2.1 million relating to an increase in the estimated amount of statutory depletion carryforward.

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

NOTE 12 - 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)		
1999:			
Capitalized costs:			
Proved properties	$ 301,725	$ 508	$ 302,233
Unproved properties	9,654	382	10,036
	311,379	890	312,269
Accumulated depreciation, depletion, amortization and impairment	(158,147)	(420)	(158,567)
Net capitalized costs	$ 153,232	$ 470	$ 153,702
Cost incurred:			
Unproved properties	$ 1,724	$ 101	$ 1,825
Producing properties	3,733	28	3,761
Exploration	2,037	-	2,037
Development	13,909	-	13,909
Total costs incurred	$ 21,403	$ 129	$ 21,532
2000:			
Capitalized costs:			
Proved properties	$ 338,159	$ 553	$ 338,712
Unproved properties	10,795	200	10,995
	348,954	753	349,707
Accumulated depreciation, depletion, amortization and impairment	(176,515)	(435)	(176,950)
Net capitalized costs	$ 172,439	$ 318	172,757
Cost incurred:			
Unproved properties	$ 5,522	$ 16	$ 5,538
Producing properties	3,752	45	3,797
Exploration	2,409	-	2,409
Development	28,140	-	28,140
Total costs incurred	$ 39,823	$ 61	$ 39,884

	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	$ 7,503	$ 21	$ 7,524
Producing properties	1,419	-	1,419
Exploration	9,336	-	9,336
Development	38,359	295	38,654
Total costs incurred	$ 56,617	$ 316	$ 56,933

The results of operations for producing activities are provided below.

	USA	CANADA	TOTAL
	(In thousands)		
1999:			
Revenues	$ 42,999	$ 63	$ 43,062
Production costs	(11,739)	(20)	(11,759)
Depreciation, depletion, amortization and impairment	(16,848)	(8)	(16,856)
	14,412	35	14,447
Income tax expense	(4,387)	(14)	(4,401)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 10,025	$ 21	$ 10,046
2000:			
Revenues	$ 88,461	$ 110	$ 88,571
Production costs	(16,457)	(19)	(16,476)
Depreciation, depletion and amortization	(18,258)	(15)	(18,273)
	53,746	76	53,822
Income tax expense	(20,350)	(30)	(20,380)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 33,396	$ 46	$ 33,442
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

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)			
1999:						
Proved developed and undeveloped reserves:						
Beginning of year	3,629	175,884	-	523	3,629	176,407
Revision of previous estimates	1,046	1,308	-	81	1,046	1,389
Extensions, discoveries and other additions	157	19,398	-	-	157	19,398
Purchases of minerals in place	139	7,922	-	-	139	7,922
Sales of minerals in place	(20)	(340)	-	-	(20)	(340)
Production	(424)	(17,402)	-	(35)	(424)	(17,437)
End of Year	4,527	186,770	-	569	4,527	187,339
Proved developed reserves:						
Beginning of year	2,749	134,504	-	421	2,749	134,925
End of year	3,583	144,992	-	467	3,583	145,459
2000:						
Proved developed and undeveloped reserves:						
Beginning of year	4,527	186,770	-	569	4,527	187,339
Revision of previous estimates	(45)	6,385	-	(82)	(45)	6,303
Extensions, discoveries and other additions	286	37,896	-	-	286	37,896
Purchases of minerals in place	229	4,893	-	-	229	4,893
Sales of minerals in place	(326)	(1,509)	-	-	(326)	(1,509)
Production	(488)	(19,239)	-	(46)	(488)	(19,285)
End of Year	4,183	215,196	-	441	4,183	215,637
Proved developed reserves:						
Beginning of year	3,583	144,992	-	467	3,583	145,459
End of year	3,222	162,718	-	389	3,222	163,107

	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

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 our reserves as prepared by our reservoir engineers.

Proved reserves are those quantities which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves, which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data as previously explained. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth herein is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves nor of estimated future cash flows.

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

	USA	**CANADA**	**TOTAL**
		(In thousands)	
1999:			
Future cash flows	$ 557,915	$ 1,281	$ 559,196
Future production and development costs	(213,929)	(344)	(214,273)
Future income tax expenses	(81,039)	(175)	(81,214)
Future net cash flows	262,947	762	263,709
10% annual discount for estimated timing of cash flows	(95,722)	(285)	(96,007)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 167,225	$ 477	$ 167,702
2000:			
Future cash flows	$2,260,796	$ 4,155	$2,264,951
Future production and development costs	(484,900)	(433)	(485,333)
Future income tax expenses	(574,099)	(1,099)	(575,198)
Future net cash flows	1,201,797	2,623	1,204,420
10% annual discount for estimated timing of cash flows	(527,210)	(1,184)	(528,394)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 674,587	$ 1,439	$ 676,026
2001:			
Future cash flows	$ 676,051	$ 975	$ 677,026
Future production and development costs	(279,499)	(341)	(279,840)
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

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

	USA	CANADA	TOTAL
	(In thousands)		
1999:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (31,260)	$ (44)	$ (31,304)
Net changes in prices and production costs	42,319	23	42,342
Revisions in quantity estimates and changes in production timing	987	44	1,031
Extensions, discoveries and improved recovery, less related costs	24,035	-	24,035
Purchases of minerals in place	8,612	-	8,612
Sales of minerals in place	(320)	-	(320)
Accretion of discount	8,096	44	8,140
Net change in income taxes	(18,355)	7	(18,348)
Other - net	1,888	4	1,892
Net change	36,002	78	36,080
Beginning of year	131,223	399	131,622
End of year	$ 167,225	$ 477	$ 167,702
2000:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (72,005)	$ (91)	$ (72,096)
Net changes in prices and production costs	647,313	1,854	649,167
Revisions in quantity estimates and changes in production timing	44,991	(324)	44,667
Extensions, discoveries and improved recovery, less related costs	184,624	-	184,624
Purchases of minerals in place	23,144	-	23,144
Sales of minerals in place	(3,469)	-	(3,469)
Accretion of discount	19,881	51	19,932
Net change in income taxes	(293,357)	(581)	(293,938)
Other - net	(43,760)	53	(43,707)
Net change	507,362	962	508,324
Beginning of year	167,225	477	167,702
End of year	$ 674,587	$ 1,439	$ 676,026

	USA	CANADA	TOTAL
		(In thousands)	
2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (68,174)	$ (167)	$ (68,341)
Net changes in prices and production costs	(768,295)	(1,600)	(769,895)
Revisions in quantity estimates and changes in production timing	(32,705)	13	(32,692)
Extensions, discoveries and improved recovery, less related costs	54,127	-	54,127
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	(54,634)	(108)	(54,742)
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

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 errors 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 ($17.71) and natural gas ($2.51) 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 ACCOUNTANTS

The Shareholders and Board of Directors
Unit Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, 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, 2000 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the accompanying financial statement schedule 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.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 20, 2002

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

None.

PART III

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

The table below and accompanying footnotes set forth certain information concerning each of our executive officers. Unless otherwise indicated, each has served in the positions set forth for more than five years. Executive officers are elected for a term of one year. There are no family relationships between any of the persons named.

NAME	AGE	POSITION
John G. Nikkel	67	President, Chief Executive Officer, Chief Operating Officer and Director
Earle Lamborn	67	Senior Vice President, Drilling and Director
Philip M. Keeley	60	Senior Vice President, Exploration and Production
Larry D. Pinkston	47	Vice President, Treasurer and Chief Financial Officer
Mark E. Schell	44	General Counsel and Secretary

Mr. Nikkel joined Unit in 1983 as its President and a director. On July 1, 2001, Mr. Nikkel was elected to the additional office of 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 that Company 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. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Lamborn has been actively involved in the oil field for over 49 years, joining Unit’s predecessor in 1952 prior to it becoming a publicly-held corporation. He was elected Vice President, Drilling in 1973 and to his current position as Senior Vice President and director in 1979.

Mr. Keeley joined Unit in November 1983 as a 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 December 2001 served as the 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. Pinkston joined Unit in December 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed as Controller in February 1985. He has been Treasurer since December 1986 and was elected to the position of Vice President and Chief Financial Officer in May 1989. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

Mr. Schell joined Unit in January of 1987, as its Secretary and General Counsel. 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.

The balance of the information required in this Item 10 is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 2002 annual meeting of stockholders.

Item 11. *Executive Compensation*

Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2002 annual meeting of stockholders.

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

Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2002 annual meeting of stockholders.

Item 13. *Certain Relationships and Related Transactions*

Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2002 annual meeting of stockholders.

PART IV

Item 14. ***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, 2000 and 2001
- Consolidated Statements of Operations for the years ended December 31, 1999, 2000 and 2001
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 1999, 2000 and 2001
- Consolidated Statements of Cash Flows for the years ended December 31, 1999, 2000 and 2001
- Notes to Consolidated Financial Statements
- Report of Independent Accountants

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 1999, 2000 and 2001:

- 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:

10.2.41 Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).

21 Subsidiaries of the Registrant (filed herewith).

23 Consent of Independent Accountants (filed herewith).

(b) Reports on Form 8-K:

No reports on Form 8-K were filed during the quarter ended December 31, 2001.

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, 1999	$ 434	$ 305	$ 15	$ 583
Year ended December 31, 2000	$ 583	$ 350	$ 14	$ 919
Year ended December 31, 2001	$ 919	$ -	$ 315	$ 604

Deferred Tax Asset Valuation Allowance:

Description	Balance at Beginning of period	Additions	Deductions	Balance At End of Period
		(In thousands)		
Year ended December 31, 1999	$ 530	$ -	$ 195	$ 335
Year ended December 31, 2000	$ 335	$ -	$ 335	$ -
Year ended December 31, 2001	$ -	$ -	$ -	$ -

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 7, 2002

By: /s/ John G. Nikkel

JOHN G. NIKKEL
President and Chief 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 20th day of March, 2001.

Name	Title
/s/ King P. Kirchner **KING P. KIRCHNER**	Chairman of the Board and Director
/s/ John G. Nikkel **JOHN G. NIKKEL**	President and Chief Executive Officer Chief Operating Officer, Director
/s/ Earle Lamborn **EARLE LAMBORN**	Senior Vice President, Drilling, Director
/s/ Larry D. Pinkston **LARRY D. PINKSTON**	Vice President, Chief Financial Officer and Treasurer
/s/ Stanley W. Belitz **STANLEY W. BELITZ**	Controller
/s/ J. Michael Adcock **J. MICHAEL ADCOCK**	Director
/s/ Don Cook **DON COOK**	Director
/s/ William B. Morgan **WILLIAM B. MORGAN**	Director
JOHN S. ZINK	Director
/s/ John H. Williams **JOHN H. WILLIAMS**	Director