FORM 10-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, 1996

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

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

Warrants to Purchase Shares of Common Stock
(Title of Class)

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 10, 1997 - $171,630,448

Number of Shares of Common Stock
Outstanding on March 10, 1997 - 24,176,734

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 7, 1997 are incorporated by reference in Part III.

Exhibit Index - See Page 76

FORM 10-K

UNIT CORPORATION

TABLE OF CONTENTS

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 1996

PART I

Item 1. Business and Item 2. Properties

GENERAL

The Company, through its wholly owned subsidiaries, is engaged in the land contract drilling of oil and natural gas wells and the development, acquisition and production of oil and natural gas properties. The Company operates primarily in the Anadarko and Arkoma Basins, which cover portions of Oklahoma, Texas, Kansas and Arkansas and has additional producing properties located in Canada and other states, including but not limited to, New Mexico, Louisiana, North Dakota, Colorado, Wyoming, Montana, Alabama and Mississippi.

The Company was originally incorporated in Oklahoma in 1963 as Unit Drilling Company. In 1979 it became a publicly held Delaware corporation and changed its name to Unit Drilling and Exploration Company ("UDE") to more accurately reflect the importance of its oil and natural gas business. In September 1986, pursuant to a merger and exchange offer, the Company acquired all of the assets and assumed all of the liabilities of UDE and six oil and gas limited partnerships for which UDE was the general partner, in exchange for shares of the Company's common stock (the "Exchange Offer").

The Company's principal executive offices are maintained at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; telephone number (918) 493-7700. The Company also has regional offices in Moore, Oklahoma, Booker, Texas and Houston, Texas. As used herein, the term "Company" refers to Unit Corporation and at times Unit Corporation and/or one or more of its subsidiaries with respect to periods from and after the Exchange Offer and to UDE with respect to periods prior thereto.

OIL AND NATURAL GAS OPERATIONS

In 1979, the Company began to acquire oil and natural gas properties to diversify its source of revenues which had previously been derived from contract drilling. The development, production and sale of oil and natural gas together with the acquisition of producing properties now constitutes the largest part of the Company's operations as conducted through its wholly owned subsidiary, Unit Petroleum Company.

As of December 31, 1996, the Company had 5,204 Mbbls and 129,161 MMcf of estimated proved oil and natural gas reserves, respectively. The Company's 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 and Canada. As of December 31, 1996, the Company had an interest in a total of 2,247 wells in the United States and served as the operator of 502 wells. The Company also had an interest in 64 wells located in Canada. The majority of the Company's development and exploration prospects are generated by its technical staff. When the Company is the operator of a property, it generally employs its own drilling rigs and the Company's own engineering staff supervises the drilling operation.

The Company intends to continue the growth in its oil and natural gas operations utilizing funds generated from operations and its bank revolving line of credit.

Well and Leasehold Data. The Company's oil and natural gas exploration and development drilling activities and the number of wells in which the Company had an interest, which were producing or capable of producing, were as follows for the periods indicated:

	Year Ended December 31,					
	1996		1995		1994	
Wells drilled:	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil.............	-	-	-	-	-	-
Natural gas......	-	-	-	-	1	.98
Dry.............	-	-	-	-	2	.80
Total	-	-	-	-	3	1.78
Development:						
Oil.............	10	8.35	15	4.70	5	5.00
Natural gas......	55	19.46	26	7.02	40	13.46
Dry.............	7	4.26	6	2.27	12	7.26
Total	72	32.07	47	13.99	57	25.72
Oil and natural gas wells producing or capable of producing:						
Oil - USA........	717	197.71	750	207.80	675	177.68
Oil - Canada.....	-	-	-	-	-	-
Gas - USA........	1,530	242.09	1,820	232.03	1,089	179.99
Gas - Canada.....	64	1.60	65	1.63	61	1.53
Total	2,311	441.40	2,635	441.46	1,825	359.20

The following table summarizes the Company's acreage as of the end of each of the years indicated:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
1996				
USA	455,713	115,326	29,245	19,124
Canada	39,040	976	-	-
Total	494,753	116,302	29,245	19,124
1995				
USA	548,674	117,403	24,810	12,866
Canada	31,360	784	-	-
Total	580,304	118,187	24,810	12,866
1994				
USA	340,241	100,732	21,514	11,540
Canada	31,360	784	-	-
Total	371,601	101,516	21,514	11,540

Price and Production Data. The 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, experienced by the Company, for the periods indicated were as follows:

	Year Ended December 31, 1996	1995	1994
Average sales price per barrel of oil produced:			
USA	$ 20.40	$ 16.65	$ 15.13
Canada	$ -	$ -	$ -
Average sales price per Mcf of natural gas produced:			
USA	$ 2.21	$ 1.61	$ 1.86
Canada	$ 1.18	$ 0.98	$ 1.27
Oil production (Mbbls):			
USA	579	577	406
Canada	-	-	-
Total	579	577	406
Natural gas production (MMcf):			
USA	12,974	12,005	9,606
Canada	51	54	53
Total	13,025	12,059	9,659
Average production expense per equivalent Mcf:			
USA	$ .68	$ 0.64	$ 0.58
Canada	$ .27	$ 0.30	$ 0.37

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

	Year Ended December 31, 1996	1995	1994
Oil (Mbbls):			
USA	5,204	5,428	4,308
Canada	-	-	-
Total	5,204	5,428	4,308
Natural gas (MMcf):			
USA	128,408	107,950	92,566
Canada	753	778	794
Total	129,161	108,728	93,360

Further information relating to oil and natural gas operations is presented in Notes 1,4,11 and 13 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

LAND CONTRACT DRILLING OPERATIONS

Unit Drilling Company, a wholly owned subsidiary of the Company, engages in the land drilling of oil and natural gas wells for a wide range of customers. A land drilling rig consists, in part, of engines, drawworks or hoists, derrick or mast, pumps to circulate the drilling fluid, blowout preventers and drill pipe. An active maintenance and replacement program during the life of a drilling rig permits upgrading of components on an individual basis. Over the life of a typical rig, due to the normal wear and tear of operating up to 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 as required, while other components, such as the substructure, mast and drawworks, can be utilized for extended periods of time with proper maintenance. The Company also owns additional equipment used in the operation of its rigs, including large air compressors, trucks and other support equipment.

In September 1996, the Company purchased one 1,500 horsepower rig and one 2,500 horsepower rig and 36,000 feet of drill pipe for $1.7 million bringing the Companies operational rig fleet at December 31, 1996 to 24 with rated depth capacities ranging from 5,000 to 25,000 feet. A majority of the Company's rigs are located in the Anadarko and Arkoma Basins of Oklahoma and Texas. In July 1994, the Company began moving rigs to the South Texas basin region thereby expanding the Company's market area for its contract drilling services and in December 1995, the contract drilling operations opened a regional office in Houston, Texas. At December 31, 1996, the Company had 3 of its larger horsepower rigs in South Texas. In the Anadarko and Arkoma Basins the Company's primary focus is on the utilization of its medium depth rigs which have a depth range of 8,000 to 14,000 feet. These medium depth rigs are suited to the contract drilling currently undertaken by operators in these two basins.

At present, the Company does not have a shortage of rig equipment. However, certain grades of drill pipe are in high demand due to increases in the Company's rig utilization so the Company has increased its drill pipe acquisitions to maintain current utilization levels. There is no assurance that sufficient supplies of such equipment will be readily available in the future and, given the general decline experienced in the land contract drilling industry over the past decade, the Company's ability to utilize its full complement of drilling rigs, should economic conditions improve rapidly, will be restricted due to a lack of availability of additional equipment, drill pipe and qualified labor not only within the Company but in the industry as a whole.

The following table sets forth, for each of the periods indicated, certain data concerning the Company's contract drilling operations:

	Year Ended December 31,				
	1996	1995	1994	1993	1992
Number of operational rigs owned at end of period	24	22	25	25	26
Average number of rigs utilized(1)	14.7	10.9	9.5	8.0	5.5
Number of wells drilled	130	111	95	84	56
Total footage drilled (feet in 1000's)	1,468	1,196	1,027	788	527

- -------------------

(1) Utilization rates are based on a 365-day year. A rig is considered utilized when it is operating or being moved, assembled or dismantled under contract.

As of March 10, 1997, 20 of the Company's 24 drilling rigs were operating under contract.

The following table sets forth, as of March 10, 1997, the type and approximate depth capability of each of the Company's drilling rigs:

Type	Approximate Depth Capability (feet)
U-15 Unit Rig	11,000
U-15 Unit Rig	11,000
U-15 Unit Rig	11,000
U-15 Unit Rig	11,000
Gardner Denver 800	15,000
Gardner Denver 700	15,000
BDW 800-M1	15,000
Gardner Denver 700	15,000
Mid-Continent 914-C	20,000
U-15 Unit Rig	11,000
Brewster N-75	15,000
Gardner Denver 500	12,000
Gardner Denver 700	15,000
Gardner Denver 700	15,000
Gardner Denver 700	15,000
Brewster N-75A	15,000
BDW 1350-M	20,000
SU-15 North Texas Machine	12,000
SU-15 North Texas Machine	12,000
National 110-UE	20,000
Continental Emsco C-1-E	20,000
Gardner Denver 1500-E	25,000
Mid-Continent 914-EC	20,000
Mid-Continent 1220-EB	25,000

For the past several years, the Company's contract drilling services have encountered significant competition due to depressed levels of activity in contract drilling. In the last 6 months of 1996, the Company's drilling operations showed significant improvements in rig utilization, but it is anticipated that competition within the industry will, for the foreseeable future, continue to adversely affect the Company.

Drilling Contracts. Most of the Company's drilling contracts are obtained through competitive bidding. Generally, the 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 the Company 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. The Company generally indemnifies its customers against certain types of claims by the Company's employees and claims arising from surface pollution caused by spills of fuel, lubricants and other solvents within the control of the Company. Such customers generally indemnify the Company against claims arising from other surface and subsurface pollution other than claims resulting from the Company's gross negligence.

The contracts may provide for compensation to the Company on a day rate, footage or turnkey basis with additional compensation for special risks and unusual conditions. Under daywork contracts, the Company provides the drilling rig with the required personnel to the operator who supervises the drilling of the contracted well. Compensation to the Company is based on a negotiated rate per day as the rig is utilized. Footage contracts usually require the Company to bear some of the drilling costs in addition to providing the rig. The Company is compensated on a rate per foot drilled basis upon completion of the well. Under turnkey contracts, the Company contracts to drill a well to a specified depth and provides most of the equipment and services required. The Company bears the risk of drilling the well to the contract depth and is compensated when the contract provisions have been satisfied.

Turnkey drilling operations, in particular, might result in losses if the Company underestimates the costs of drilling a well or if unforeseen events occur. Because the proportion of turnkey drilling is currently dictated by market conditions and the desires of customers using the Company's services, the Company is unable to predict whether the portion of drilling conducted on a turnkey basis will increase or decrease in the future. For 1996, turnkey revenue represented approximately 8 percent of the Company's contract drilling revenues. To date, the Company has not experienced significant losses in performing turnkey contracts.

Customers. During the fiscal year ended December 31, 1996, 10 contract drilling customers accounted for approximately 22 percent of the Company's total revenues and approximately 3 percent of the Company's total revenues were generated by drilling on oil and natural gas properties of which the Company was the operator (including properties owned by limited partnerships for which the Company acted as general partner). Such drilling was pursuant to contracts containing terms and conditions comparable to those contained in the Company's customary drilling contracts with non-affiliated operators.

Further information relating to contract drilling operations is presented in Notes 1 and 11 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

NATURAL GAS MARKETING

Prior to April 1995, the Company marketed natural gas from wells located primarily in Oklahoma and Texas and to a lesser extent in Arkansas, Kansas, Louisiana, Mississippi and New Mexico. Effective April 1, 1995 the Company completed a business combination between the Company's natural gas marketing operations and a third party also involved in natural gas marketing activities forming a new company called GED Gas Services, L.L.C. ("GED"). The Company owns a 34 percent interest in GED. Effective November 1, 1995, GED sold its natural gas marketing operations to a third party. This sale removed the Company from the third party natural gas marketing business. The creation of GED and the subsequent sale of the marketing operations did not adversely affect the Company's drilling and oil and natural gas exploration operations or the profitability of the Company as a whole. The disposition of the Company's natural gas marketing segment was accounted for as a discontinued operation and accordingly, the 1995 and prior year financial information were restated to reflect this treatment.

MARKETING OF OIL AND NATURAL GAS PRODUCTION

The Company's revenue and profitability are substantially dependent upon prevailing prices for natural gas and crude oil. These prices vary based on factors beyond the control of the Company, including the extent of domestic production and importation of crude oil and natural gas, the proximity and capacity of oil and natural gas pipelines, the marketing of competitive fuels, general fluctuations in the supply and demand for oil and natural gas, the effect of federal and state regulation of production, refining, transportation and sales, the use and allocation of oil and natural gas and their substitute fuels and general national and worldwide economic conditions. In addition, natural gas spot prices received by the Company are influenced by weather conditions impacting the continental United States.

The Company's oil and condensate production is sold at or near the Company's wells under purchase contracts at prevailing prices in accordance with arrangements which are customary in the oil industry. The Company's natural gas production is sold at the wellhead to intrastate and interstate pipelines as well as to independent marketing firms under contracts with original terms ranging from one month to 20 years. Most of these contracts contain provisions for readjustment of price, termination and other terms which are customary in the industry.

The worldwide supply of oil has been largely dependent upon rates of production of foreign reserves. Although the demand for oil has increased slightly in the United States, imports of foreign oil continue to increase. Future domestic oil prices will depend largely upon the actions of foreign producers with respect to rates of production and it is virtually impossible to predict what actions those producers will take in the future. Prices may also be affected by political, social and other factors relating to the Middle East. In view of the many uncertainties affecting the supply and demand for oil and natural gas, the Company is unable to predict future oil and natural gas prices or the overall effect, if any, that a decline in demand or oversupply of such products would have on the Company.

COMPETITION

All lines of business in which the Company engages are highly competitive. Competition in land contract drilling traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of the Company's competitors in the land contract drilling business are substantially larger than the Company and have appreciably greater financial and other resources. As a result of the decrease in demand for land contract drilling services over the past decade, a surplus of certain types of drilling rigs currently exists while inventories of certain components such as drill pipe have been depleted from continued use. Accordingly, the competitive environment within which the Company's drilling operations presently operates is uncertain and extremely price oriented.

The Company's 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 the Company.

OIL AND NATURAL GAS PROGRAMS

The Company currently serves as a general partner to 4 oil and gas limited partnerships and 8 employee oil and gas limited partnerships. The employee partnerships acquire an interest fixed annually ranging from 5% to 15% of the Company's interest in most oil and natural gas drilling activities and purchases of producing oil and natural gas properties participated in by the Company. The limited partners in the employee partnerships are either employees or directors of the Company or its subsidiaries.

Under the terms of the partnership agreements of each limited partnership, the general partner, which in each case is Unit Petroleum Company, 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 eliminate entirely such conflicts. Additionally, conflicts of interest may arise where the Company is the operator of an oil and natural gas well and also provides contract drilling services. Although the Company has no formal procedures for resolving such conflicts, the Company believes it fulfills its responsibility to each contracting party and complies fully with the terms of the agreements which regulate such conflicts.

Depending upon a number of factors, including the performance of the drilling programs and general economic and capital market conditions, the Company may form additional drilling and/or producing property acquisition programs in the future.

EMPLOYEES

As of March 10, 1997, the Company had approximately 402 employees in its land contract drilling operations, 59 employees in its oil and natural gas operations and 25 in its general corporate area. None of the Company's employees are represented by a union or labor organization nor have the Company's operations ever been interrupted by a strike or work stoppage. The Company considers relations with its employees to be satisfactory.

OPERATING AND OTHER RISKS

The Company's land contract drilling and oil and natural gas operations are subject to a variety of oil field hazards such as fire, explosion, blowouts, cratering and oil spills or certain other types of possible surface and subsurface pollution, any of which can cause personal injury and loss of life and severely damage or destroy equipment, suspend drilling operations and cause substantial damage to surrounding areas or property of others. As protection against some, but not all, of these operating hazards, the Company maintains broad insurance coverage, including all-risk physical damage, employer's liability and comprehensive general liability. In all states in which the Company operates except Oklahoma, the Company maintains worker's compensation insurance for losses exceeding $50,000. In Oklahoma, starting in August 1991, the Company elected to become self insured. In consideration therewith, the Company purchased an excess liability reinsurance policy. The Company believes that to the extent reasonably practicable such insurance coverages are adequate. The Company's insurance policies do not, however, provide protection against revenue losses incurred by reason of business interruptions caused by the destruction or damage of major items of equipment nor certain types of hazards such as specific types of environmental pollution claims. In view of the difficulties which may be encountered in renewing such insurance at reasonable rates, no assurance can be given that the Company

will be able to maintain the amount of insurance coverage which it considers adequate at reasonable rates. Moreover, loss of or serious damage to any of the Company's equipment, although adequately covered by insurance, could have an adverse effect upon the Company's earning capacity.

The Company's oil and natural gas operations are also subject to all of the risks and hazards typically associated with the search for and production of oil and natural gas. These include the necessity of expending large sums of money for the location and acquisition of properties and for drilling exploratory wells. In such exploratory work, many failures and losses may occur before any accumulation of oil or natural gas is found. If oil or natural gas is encountered, there is no assurance that it will be capable of being produced or will be in quantities sufficient to warrant development or that it can be satisfactorily marketed. The Company's future natural gas and crude oil revenues and production, and therefore cash flow and income, are highly dependent upon the Company's level of success in acquiring or finding additional reserves. Without continuing reserve additions through exploration or acquisitions, the Company's reserves and production will decline over the long-term.

GOVERNMENTAL REGULATIONS

The production and sale of oil and natural gas is highly affected by various state and federal regulations. All states in which the Company conducts activities impose restrictions on the drilling, production and sale of oil and natural gas, which often include requirements relating to well spacing, waste prevention, production limitations, pollution prevention and clean-up, obtaining drilling permits and similar matters. The following discussion summarizes, in part, the regulations of the United States oil and natural gas industry and is not intended to constitute a complete discussion of the many statutes, rules, regulations and governmental orders to which the Company's operations may be subject.

The Company's activities are subject to existing federal and state laws and regulations governing environmental quality and pollution control. Various states and governmental agencies are considering, and some have adopted, laws and regulations regarding environmental control which could adversely affect the business of the Company. Such laws and regulations may substantially increase the costs of doing business and may prevent or delay the commencement or continuation of given operations. Compliance with such legislation and regulations, together with any penalties resulting from noncompliance therewith, will increase the cost of oil and natural gas drilling, development, production and processing. In the opinion of the Company's management, its operations to date comply in all material respects with applicable environmental legislation and regulations; however, in view of the many uncertainties with respect to the current controls, including their duration, interpretation and possible modification, the Company can not predict the overall effect of such controls on its operations.

On July 26, 1989, the Natural Gas Wellhead Decontrol Act of 1989 (the "Wellhead Decontrol Act") became effective. Under the Wellhead Decontrol Act, all remaining price and non-price controls of first sales under the NGA and NGPA were removed effective January 1, 1993. Prices for deregulated categories of natural gas fluctuate in response to market pressures which currently favor purchasers and disfavor producers. As a result of the deregulation of a greater proportion of the domestic United States natural gas market and an increase in the availability of natural gas transportation, a competitive trading market for natural gas has developed.

During the past several years, the Federal Energy Regulatory Commission ("FERC") has adopted several regulations designed to accomplish a more competitive, less regulated market for natural gas. These regulations have materially affected the market for natural gas. The major elements of several of these initiatives remain subject to appellate review.

One of the initiatives FERC adopted was order 636. In brief, the primary requirements of Order 636 are as follows: pipelines must separate their sales and transportation services; pipelines must provide open access transportation services that are equal in quality for all natural gas suppliers and must provide access to storage on an open access contract basis; pipelines that provide firm sales service on May 18, 1992 must offer a "no-notice" firm transportation service under which firm shippers may receive delivery of natural gas on demand up to their firm entitlement without incurring daily balancing and scheduling penalties; pipelines must provide all shippers with equal and timely access to information relevant to the availability of their open access transportation services; open access pipelines must allow firm transportation customers to downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines; pipelines must implement a capacity releasing program so that firm shippers can release unwanted capacity to those desiring capacity (which program replaces previous "capacity brokering" and "buy-sell" programs); existing bundled firm sales entitlement are converted to unbundled firm sales entitlement and to unbundled firm transportation rights on the effective date of a particular pipeline's blanket sales certificate; and pipeline transportation rights must be developed under the Straight Fixed Variable (SFV) method of cost classification, allocation and rate design unless the FERC permits the pipeline to use some other method. The FERC will not permit a pipeline to change the new resulting rates until the FERC accepts the pipeline's formal restructuring plans.

In essence, the goal of Order 636 is to make a pipeline's position as natural gas merchant indistinguishable from that of a non-pipeline supplier. It, therefore, pushes the point of sale of natural gas by pipelines upstream, perhaps all the way to the wellhead. Order 636 also requires pipelines to give firm transportation customers flexibility with respect to receipt and delivery points (except that a firm shipper's choice of delivery point cannot be downstream of the existing primary delivery point) and to allow "no-notice" service (which means that natural gas is available not only simultaneously but also without prior nomination, with the only limitation being the customer's daily contract demand) if the

pipeline offered no-notice city-gate sales service on May 18, 1992. Thus, this separation of pipelines' sales and transportation allows non-pipeline sellers to acquire firm downstream transportation rights and thus to offer buyers what is effectively a bundled city-gate sales service and it permits each customer to assemble a package of services that serves its individual requirements. But it also makes more difficult the coordination of natural gas supply and transportation. A corollary to these changes is that all pipelines will be permitted to sell natural gas at market-based rates.

The results of these changes may be the increased availability of firm transportation and the reduction of interruptible transportation, with a corresponding reduction in the rates for off-peak and interruptible transportation. Due to the continuing judicial review of Order 636 and the continuing evolutionary nature of Order 636 and its implementation, it is not possible to project the overall potential impact on transportation rates for natural gas or market prices of natural gas.

The future interpretation and application by FERC of these rules and its broad authority, or of the state and local regulations by the relevant agencies, could affect the terms and availability of transportation services for transportation of natural gas to customers and the prices at which natural gas can be sold by the Company. For instance, as a result of Order 636, more interstate pipeline companies have begun divesting their gathering systems, either to unregulated affiliates or to third persons, a practice which could result in separate, and higher, rates for gathering a producer's natural gas. In proceedings during mid and late 1994 allowing various interstate natural gas companies' spindowns or spinoffs of gathering facilities, the FERC held that, except in limited circumstances of abuse, it generally lacks jurisdiction over a pipeline's gathering affiliates, which neither transport natural gas in interstate commerce nor sell gas in interstate commerce for resale. However, pipelines spinning down gathering systems have to include two Order No. 497 standards of conduct in their tariffs: nondiscriminatory access to transportation for all sources of supply and no tying of pipeline transportation service to any service by the pipeline's gathering affiliate. In addition, if unable to reach a mutually acceptable gathering contract with a present user of the gathering facilities, the FERC required that the pipeline must offer a two-year "default contract" to existing users of the gathering facilities. However, on appeal, while the United States Court of Appeals for the District of Columbia upheld the FERC's allowing the spinning down of gathering facilities to a non-regulated affiliate, in Conoco Inc. v. FERC, 90 F.3d 536, 552-53 (D.C. Cir. 1996)the D.C. Circuit remanded the FERC's default contract mechanism.

Additional proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue. Sales of petroleum liquids by the Company are not currently regulated and are made at market prices; however, the FERC is considering a proposal that could increase transportation rates for petroleum liquids. A number of legislative proposals have also been introduced in Congress and the state legislatures of various states, that,

if enacted, would significantly affect the petroleum industry. Such proposals involve, among other things, the imposition of land and use controls and certain measures designed to prevent petroleum companies from acquiring assets in other energy areas. In addition, there is always the possibility that if market conditions change dramatically in favor of oil and natural gas producers that some new form of "windfall profits" or severance tax may be proposed and imposed upon oil or natural gas. At the present time it is impossible to predict which proposals, if any, will actually be enacted by Congress or the various state legislatures. The Company believes that it is complying with all orders and regulations applicable to its operations. However, in view of the many uncertainties with respect to the current controls, including their duration and possible modification together with any new proposals that may be enacted, the Company cannot predict the overall effect, if any, of such controls on Company operations.

Certain states in which the Company operates control production from wells through regulations establishing the spacing of wells, limiting the number of days in a given month during which a well can produce and otherwise limiting the rate of allowable production.

As noted above, the Company's operations are subject to numerous federal and state laws and regulations regarding the control of contamination of the environment. These laws and regulations may require the acquisition of a permit before or after drilling commences, prohibit drilling activities on certain lands lying within wilderness areas or where pollution arises and impose substantial liabilities for pollution resulting from drilling operations, particularly operations in offshore waters or on submerged lands.

A past, present, or future release or threatened release of a hazardous substance into the air, water, or ground by the Company or as a result of disposal practices may subject the Company to liability under the Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), the Resource Conservation Recovery Act ("RCRA"), the Clean Water Act, and/or similar state laws, and any regulations promulgated pursuant thereto. Under CERCLA and similar laws, the Company may be fully liable for the cleanup costs of a release of hazardous substances even though it contributed to only part of the release. While liability under CERCLA and similar laws may be limited under certain circumstances, the limits are so high that the maximum liability would likely have a significant adverse effect on the Company. In certain circumstances, the Company may have liability for releases of hazardous substances by previous owners of Company properties. CERCLA currently excludes petroleum from its definition of "hazardous substances." However, Congress may delete this exclusion for petroleum, in which case the Company would be required to manage its petroleum production and wastes from its exploration and production activities as CERCLA hazardous substances. In addition, RCRA classifies certain oil field wastes as "non-hazardous." Congress may delete this exemption for oilfield waste, in which case the Company would have to manage much of its oilfield waste as hazardous. Additionally, the discharge or substantial threat of a discharge of oil by the Company into United States waters or onto an adjoining shoreline may subject the Company

to liability under the Oil Pollution Act of 1990 and similar state laws. While liability under the Oil Pollution Act of 1990 is limited under certain circumstances, the maximum liability under those limits would still likely have a significant adverse effect on the Company.

Violation of environmental legislation and regulations may result in the imposition of fines or civil or criminal penalties and, in certain circumstances, the entry of an order for the abatement of the conditions, or suspension of the activities, giving rise to the violation. The Company believes that the Company has complied with all orders and regulations applicable to its operations. However, in view of many uncertainties with respect to the current controls, including their duration and possible modification, the Company cannot predict the overall effect of such controls on such operations. Similarly, the Company cannot predict what future environmental laws may be enacted or regulations may be promulgated and what, if any, impact they would have on operations.

SAFE HARBOR STATEMENT OF FURTHER ACTIVITY

In the normal course of its business, the Company, in an effort to help keep its shareholders and the public informed about the Company's operations, may, from time to time, issue certain statements, either in writing or orally, that contain or may contain forward looking information. Generally, these statements relate to projections involving the anticipated revenues to be received from the Company's oil and natural gas production or drilling operations, the utilization rate of its drilling rigs, growth of its oil and natural gas reserves and well performance, and the Company's anticipated bank debt.

Statement in this Annual Report on Form 10-K under the captions "Business" and "Management's Discussion and Analysis of Financial Condition and Results of Operations", as well as oral statements that may be made by the Company or by officers, directors or employees of the Company acting on the Company's behalf, that are not historical facts constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Words such as "believes", "anticipates" and similar expressions, although not inclusive, identify forward-looking statements. Such forward-looking statements are subject to a number of factors that may tend to influence the accuracy of the statements and the projections upon which the statements are based. As noted elsewhere in this report, all phases of the Company's operations are subject to a number of influences outside the control of the Company, any one of which, or a combination of which, could materially affect the results of the Company's operations.

In order to provide a more thorough understanding of the possible effects of some of these influences on any projections made by the Company, the following discussion outlines certain factors that in the future could cause the Company's consolidated results for 1997 and beyond to differ materially from those that may be set forth in any such forward-looking statement made by or on behalf of the Company.

Commodity Prices

The prices received by the Company for its oil and natural gas production have a direct impact on the Company's revenues, profitability and cash flow as well as its ability to meet its projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond the control of the Company, including, but not limited to, 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 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 difference in such prices even on a month to month basis. All these factors, especially when coupled with the fact that much of the Company's product prices are determined on a month to month basis, can, and at times do, lead to wide fluctuations in the prices received by the Company.

Based upon the results of operations for the year ended December 31, 1996, the Company estimates that a change of $0.10/Mcf in the average price of natural gas and a change of $1.00/Bbl in the price of crude oil throughout such period would have resulted in approximate changes in net income before income taxes of $1,180,000 and $540,000, respectively. During 1996, 97% of the natural gas volume of the Company and substantially all the crude oil volume of the Company were sold at market responsive prices.

Customer Demand

Demand for the Company's 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 the Company's drilling rigs. These include the funds available by such companies 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 the Company's customers are small to mid-size oil and natural gas companies whose drilling budgets tend to be more susceptible to the influences of current price fluctuations. Other factors that affect the Company's ability to work its drilling rigs are the weather, which can, under adverse circumstances, delay or even cause a project to be abandoned by an operator, the competition faced by the Company in securing the award of a drilling contract in a given area, the experience and recognition of the Company in a new market area, and the availability of labor to run the Company's drilling rigs.

Uncertainty Of Oil And Natural Gas Reserves And Well Performance

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. Estimating quantities of proved reserves is imprecise. Such estimates are based upon certain assumptions pertaining to future production levels, future natural gas and crude oil prices, timing and amount of development expenditures and future operating costs made using currently available geologic, engineering and economic data, some or all of which may prove to be incorrect over time. As a result of changes in these assumptions that will occur in the future, and based upon further production history, results of future exploration and development activities, future natural gas and crude oil prices and other factors, the reported quantity of reserves may be subject to upward or downward revision.

In addition to the foregoing, projections regarding the potential production and reserve capabilities of newly drilled and/ or completed wells are subject to additional uncertainties that may significantly influence such projections. Such wells have a very limited production history, if any, on which to base future forecasts of their capabilities. Since an established rate of production is a primary factor used by reservoir engineers to forecast oil and natural gas reserves as well as a well's production rate, the lack of this information decreases the Company's ability to accurately project such information. In addition, there are inherent risks in both the drilling and completion phases of a new well which could cause a well bore to be prematurely abandoned due either to the loss of the well bore in the physical sense or due to the costs associated with operational problems which could render further operations uneconomical.

Bank Borrowing

The amount of the Company's bank debt as well as its projected borrowing is, to a large extent, a function of the costs associated with the projects undertaken by the Company at any given time and the cash flow received by the Company for its oil and natural gas production. Generally, the costs incurred by the Company in its 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 of its drilling rig fleet. To some extent, these costs, particularly the first two items, are discretionary and the Company maintains a degree of control regarding the timing and/ or the need to incur the same. However, in some cases, unforseen 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 the Company to incur increased bank debt above that which it had expected or forecast. Likewise, for many of the reasons mentioned above, the Company's cash flow may not be sufficient to cover its current cash requirements which would then require the Company to increase its bank borrowing.

Item 3. Legal Proceedings
- --------------------------

The Company is a party to various legal proceedings arising in the ordinary course of its business none of which, in the Company's opinion, should result in judgments which would have a material adverse effect on the Company.

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

No matters were submitted to the security holders during the fourth quarter of the Company's calendar year ended December 31, 1996.

PART II

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

As of February 18, 1997, the Company had 2,862 holders of record of its common stock. The Company has not paid any cash dividends on shares of its common stock since its organization and currently intends to continue its policy of retaining earnings, if any, from the Company's operations. The Company is prohibited, by certain loan agreement provisions, from declaring and paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of its consolidated net income of the preceding fiscal year. The table below reflects the high and low sales prices per share of the Company's common stock as reported by the New York Stock Exchange, Inc. for the period indicated:

	1996		1995	
QUARTER	High	Low	High	Low

First	$ 6	$ 4	$ 3 1/4	$ 2 1/2
Second	$ 7 3/8	$ 5 3/4	$ 3 7/8	$ 2 7/8
Third	$ 7 1/8	$ 5 1/2	$ 4 1/4	$ 3 1/4
Fourth	$10 1/8	$ 5 7/8	$ 4 3/4	$ 3 1/2

Item 6. Selected Financial Data

	Year Ended December 31,				
	1996	1995	1994	1993	1992
	(In thousands except per share amounts)				
Revenues	$72,070	$53,074	$43,895	$38,682	$33,744
Income From Continuing Operations	$ 8,333	$ 3,751(1)	$ 4,628(2)	$ 3,937	$ 1,631(3)
Net Income	$ 8,333	$ 3,999(1)	$ 4,794(2)	$ 3,871	$ 1,087(3)
Earnings Per Common Share:					
Continuing Operations:					
Primary	$.37	$.18(1)	$.22(2)	$.19	$.08(3)
Fully Diluted	$.36	$.18(1)	$.22(2)	$.19	$.08(3)
Net Income:					
Primary	$.37	$.19(1)	$.23(2)	$.19	$.05(3)
Fully Diluted	$.36	$.19(1)	$.23(2)	$.19	$.05(3)
Total Assets	$137,993	$110,922	$103,933	$ 88,816	$ 83,960
Long-Term Debt	$ 40,600	$ 41,100	$ 37,824	$ 25,919	$ 22,298
Long-Term Portion of Natural Gas Purchaser Prepayments	$ 2,276	$ 2,109	$ 2,149	$ 4,417	$ 5,924
Cash Dividends Per Common Share	$ -	$ -	$ -	$ -	$ -

____

(1) Includes a $635,000 gain on compressor sale, a $850,000 gain from settlement of litigation and a net $530,000 deferred tax benefit.
(2) Includes a $742,000 gain on sale of a natural gas gathering system.
(3) Includes a $1.5 million provision for litigation

See Management's Discussion of Financial Condition and Results of Operations for a review of 1996, 1995 and 1994 activity.

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

Financial Condition and Liquidity

The Company's loan agreement ("Loan Agreement"), provides for a total commitment of $75 million, consisting of a revolving credit facility through August 1, 1999 and a term loan thereafter, maturing on August 1, 2003. Borrowings under the revolving credit facility are limited to a borrowing base which is subject to a semi-annual redetermination. The latest borrowing base determination indicated $52 million of the commitment is available to the Company. The Loan Agreement contains certain covenants which require the Company to maintain consolidated net worth of at least $48 million, a modified 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 to 1 and a ratio of total liabilities, as defined in the Loan Agreement, to consolidated tangible net worth not greater than 1.25 to 1. In addition, working capital provided by operations, as defined in the Loan Agreement, cannot be less than $12 million in any year. At December 31, 1996, borrowings under the Loan Agreement totaled $40.6 million. At February 21, 1997, borrowings under the Loan Agreement totaled $36.0 million with $13.1 million available for future borrowings. The interest rate on the bank debt was 7.2 and 7.0 percent at December 31, 1996 and February 21, 1997, respectively. At the Company's election, any portion of the debt outstanding may be fixed at the London Interbank Offered Rate ("Libor Rate") for 30, 60, 90 or 180 days with the remainder of the outstanding debt subject to the Chase Manhattan Bank, N. A. prime rate. During any Libor Rate funding period, the Company may not pay in part or in whole the outstanding principal balance of the note to which such Libor Rate option applies. At both December 31, 1996 and February 21, 1997, $35.0 million of borrowings were subject to the Libor Rate. A commitment fee of 1/2 of 1 percent is charged for any unused portion of the borrowing base.

Shareholders' equity at December 31, 1996 was $78.2 million, making the Company's ratio of long-term debt-to-equity .52 to 1. The Company's primary source of liquidity and capital resources in the near- and long-term will consist of cash flow from operating activities and available borrowings under the Company's Loan Agreement. Net cash provided by continuing operating activities in 1996 was $20.7 million as compared to $11.2 million in 1995.

The Company's capital expenditures during 1996 were $36.5 million. The majority of the capital expenditures, $25.6 million, were made in the Company's oil and natural gas operations with $20.2 million and $2.3 million used for exploration and development drilling and producing property acquisitions, respectively. Capital expenditures made by the Company's contract drilling operations were $9.9 million in 1996. The drilling expenditures principally consisted of the purchase and refurbishment of two drilling rigs acquired in September 1996, the refurbishment of two drilling rigs already owned by the Company and the acquisition of over 110,000 feet of drill pipe. The Company's drilling rigs are composed of large components some of which, on a rotational basis, are required to be overhauled to assure continued proper performance. Such capital expenditures will continue in future years with approximately $6.0 million projected for 1997.

During 1997, the Company's oil and natural gas subsidiary plans to continue its focus on its developmental drilling as increased spot market natural gas prices in late 1996 and into early 1997 lessened the availability of economical producing property acquisitions. The majority of the Company's capital expenditures are discretionary and primary directed toward increasing reserves and future growth. Current operations are not dependent of the Company's ability to obtain funds outside of the Company's Loan Agreement. The decision to acquire or drill on oil and natural gas properties at any given time depends on market conditions, potential return on investment, future drilling potential and the availability of opportunities to obtain financing given the circumstances involved, thus providing the Company with a large degree of flexibility in incurring such costs. Depending, in part, on commodity pricing, the Company plans to spend approximately $31 million on its exploration capital expenditure program in 1997.

At December 31, 1995, the Company had 2.873 million warrants outstanding. The warrants entitled the holders to purchase one share of common stock at a price of $4.375 per share. Prior to the warrants expiration on August 30, 1996, 2.86 million warrants were exercised providing $12.5 million in additional capital to the Company.

The Company continued to receive monthly payments on behalf of itself and other parties (collectively the "Committed Interest") from a natural gas purchaser pursuant to a settlement agreement (the "Settlement Agreement"). As a result of the Settlement Agreement, the December 31, 1996 prepayment balance of $2.3 million paid by the purchaser for natural gas not taken (the "Prepayment Balance") is subject to recoupment in volumes of natural gas through a period ending on the earlier of recoupment or December 31, 1997 (the "Recoupment Period"). During 1997, the purchaser is obligated to make monthly payments on behalf of the Committed Interest based on their share of the natural gas deliverability of the wells subject to the Settlement Agreement, up to a maximum of $156,000 or a minimum of $80,000 per month. The monthly payments will end at the end of 1997. If natural gas is taken during a month, the value of such natural gas is credited toward the monthly amount the purchaser is required to pay. In the event the purchaser takes volumes of natural gas valued in excess of its monthly payment obligations, the value taken in excess is applied to reduce any then outstanding Prepayment Balance. The Company currently believes that sufficient natural gas deliverability is available to enable the Committed Interest to receive substantially all of the maximum monthly payments during 1997. At the end of the Recoupment Period, the Settlement

Agreement and the natural gas purchase contracts which are subject to the Settlement Agreement will terminate. If the Prepayment Balance is not fully recouped in natural gas by December 31, 1997, then the unrecouped portion is subject to cash repayment, limited to a maximum of $3 million, payable in equal annual payments over a five year period with the first payment due June 1, 1998. The Company anticipates the maximum balance of $3 million will be unrecouped at December 31, 1997. The price per Mcf under the Settlement Agreement is substantially higher than current spot market prices. The impact of the higher price received under the Settlement Agreement increased pre-tax income approximately $0.6, $1.6 and $1.8 million in 1996, 1995 and 1994, respectively.

Average oil prices received by the Company in 1996 ranged from $16.90 in February to $24.00 in December. The Company's average price received for oil during 1996 was $20.40. Natural gas prices received by the Company in 1996 ranged from an average of $1.71 in September to an average of $3.60 in December. Average natural gas prices received by the Company were volatile throughout 1996 and averaged $2.20 for the year as a whole.

Average oil prices received early in the first quarter of 1997 were 5 percent lower than average prices received by the Company at December 31, 1996 while average natural gas spot prices dropped 10 percent from the December 31, 1996 price. Oil prices within the industry remain largely dependent upon world market developments for crude oil. Prices for natural gas are influenced by weather conditions and supply imbalances, particularly in the domestic market, and by world wide oil price levels. Any drop in spot market natural gas prices would have a significant adverse effect on the value of the Company's reserves and further large drops in prices could cause the Company to reduce the carrying value of its oil and natural gas properties. Likewise, declines in natural gas or oil prices could adversely effect the Company operationally by, for example, adversely impacting future demand for its drilling rigs or financially by reducing the price received for its oil and natural gas sales and also by adversely effecting the semi-annual borrowing base determination under the Company's Loan Agreement since this determination is calculated on the value of the Company's oil and natural gas reserves.

The Company's ability to utilize its full complement of drilling rigs, is being restricted due to the lack of qualified labor and certain supporting equipment not only within the Company but in the industry as a whole. The Company's ability to utilize its drilling rigs at any given time is dependent on a number of factors, including but not limited to, the price of both oil and natural gas, the availability of labor and the Company's ability to supply the type of equipment required. The Company's management expects that these factors will continue to influence the Company's rig utilization during 1997.

In the third quarter of 1994, the Company's Board of Directors authorized the Company to purchase up to 1,000,000 shares of the Company's outstanding common stock on the open market. Since that time, 120,100 shares have been repurchased at prices ranging from $2.5 to $8.275 per share. During the first quarters of 1996 and 1995, 44,686 and 46,659, respectively, of the purchased shares were reissued as the Company's matching contribution to its 401(k) Employee Thrift Plan. At December 31, 1996, 28,755 treasury shares were held by the Company.

On April 1, 1995, the Company completed a business combination between the Company's natural gas marketing operations and a third party also involved in natural gas marketing activities forming a new company called GED Gas Services, L.L.C. ("GED"). The Company owns a 34 percent interest in GED. Effective November 1, 1995 GED sold its natural gas marketing operations to a third party. This sale removed the Company from the third party natural gas marketing business. The creation of GED and its subsequent sale of its marketing operations did not adversely affect the Company's drilling and oil and natural gas exploration operations or the profitability of the Company as a whole. The discontinuation of the Company's natural gas marketing segment was accounted for as a discontinued operation and accordingly, the 1995 and prior year financial information reflect this treatment.

Effects of Inflation

The effects of inflation on the Company's operations in previous years have been minimal due to low inflation rates. However, during the third and fourth quarters of 1996 as drilling rig day rates and drilling rig utilization has increased, the impact of inflation has intensified as shortages in related equipment, third party services and qualified labor increased. The impact on the Company in the future will depend on the relative increase, if any, the Company may realize in its drilling rig rates and the selling price of its oil and natural gas. If industry activity continues to increase substantially, shortages in support equipment such as drill pipe, third party services and qualified labor will occur resulting in additional corresponding increases in material and labor costs. These market conditions may limit the Company's ability to realize improvements in operating profits.

Results of Operations

1996 versus 1995
- ----------------

Net income for 1996 was $8,333,000, compared with $3,999,000 in 1995. Increased natural gas production from new wells drilled along with higher oil and natural gas prices, contract drilling day rates and rig utilization all combined to produce the large increase in 1996 net income. Net income in 1995 included $635,000 gain from the sale of 44 natural gas compressors and certain related support equipment which were sold for $2.7 million in the first quarter and by the receipt of $850,000 in the third quarter from a settlement reached by two of the Company's subsidiaries in certain litigation brought against the Federal Deposit Insurance Corporation and other parties. In the fourth quarter of 1995, the Company also recognized a $360,000 net gain from the Company's interest in the sale of GED's gas marketing operations and a $530,000 income tax benefit. Net income in the fourth quarter of 1995 was reduced by a $254,000 write down of certain rig components as the Company elected to take 3 of its drilling rigs out of service.

Oil and natural gas revenues increased 38 percent in 1996 due to a 8 percent increase in natural gas production combined with a 23 and 37 percent increase in average oil and natural gas prices received by the Company, respectively. Oil production remained virtually unchanged from 1995 levels. Average natural gas spot market prices received by the Company increased by 46 percent while volumes produced from certain wells included under the Settlement Agreement, which contains provisions for prices which are higher than current spot market prices, dropped by 46 percent. The impact of higher prices received under the Settlement Agreement increased pre-tax income by approximately $0.6 and $1.6 million in 1996 and 1995, respectively.

In 1996, revenues from contract drilling operations increased by 43 percent as average rig utilization increased from 10.9 rigs operating in 1995 to 14.7 rigs operating in 1996, and daywork revenues per rig per day increased 12 percent. Total daywork revenues represented 68 percent of total drilling revenues in 1996 and 57 percent in 1995. Turnkey and footage contracts typically provide for higher revenues since a greater portion of the expense of drilling the well is born by the drilling contractor.

Operating margins (revenues less operating costs) for the Company's oil and natural gas operations were 69 percent in 1996 compared to 62 percent in 1995. Increased operating margins resulted primarily from the increase in natural gas production and the increases in both oil and natural gas prices received by the Company between the two years. Total operating costs increased 12 percent primarily due to the additional costs associated with oil and natural gas production from new wells drilled in 1996.

Operating margins for contract drilling increased from 11 percent in 1995 to 16 percent in 1996. Margins in 1996 improved due to increases in daily rig rates and utilization. Margins in 1995 were limited by initial start up costs incurred in the first quarter of 1995 to establish rigs in the South Texas Basin and by unusually wet weather conditions during the second quarter of 1995 which delayed rig moves and depressed rig utilization. Total operating costs for contract drilling were up 34 percent in 1996 versus 1995 due to increased drilling rig utilization.

Contract drilling depreciation increased 13 percent in response to increased rig utilization. Depreciation, depletion and amortization ("DD&A") of oil and natural gas properties increased 6 percent as the Company increased its equivalent barrels of production by 6 percent. The Company's average DD&A rate per equivalent barrel declined from $3.93 in 1995 to $3.90 in 1996.

General and administrative expenses increased 6 percent as certain employee costs increased between the comparative years. Interest expense decreased 2 percent as the average interest rate on the Company's outstanding bank debt decreased from 8.52 percent in 1995 to 7.69 percent in 1996. The decrease in average interest rate was partially offset by an 8 percent increase in bank debt outstanding in 1996 primarily due to the financing of new wells drilled and the additional rigs and drill pipe purchased during 1996.

The Company's effective income tax rate in recent years has been significantly impacted by its net operating loss carryforwards. As of December 31, 1995, the Company's net operating loss and statutory depletion carryforwards has been fully recognized for financial reporting purposes; therefore, the Company's effective income tax rate increased in 1996 to approximately the statutory rate.

1995 versus 1994
- ----------------

Net income for 1995 was $3,999,000, compared with $4,794,000 in 1994. While the Company continued to increase natural gas production through producing property acquisitions and developmental drilling, lower 1995 natural gas prices limited corresponding increases in net income. Net income in the fourth quarter of 1995 was also further reduced by a $254,000 write down of certain rig components as the Company elected to take 3 of its drilling rigs out of service since economic conditions did not warrant the capital investment necessary to keep them in service. The impact of lower natural gas prices on net income was partially offset by a $635,000 gain from the sale of 44 natural gas compressors and certain related support equipment which were sold for $2.7 million in the first quarter and by the receipt of $850,000 in the third quarter from a settlement reached by two of the Company's subsidiaries in certain litigation brought against the Federal Deposit Insurance Corporation and other parties. In the fourth quarter, the Company also recognized a $360,000 net gain from the Company's interest in the sale of GED's gas marketing operations and a $530,000 net income tax benefit. Total revenues from continuing operations increased to $53,074,000 in 1995 as compared to $43,895,000 in 1994. The Company's 1994 net income included a net gain of $742,000 recognized in conjunction with the sale of one of the Company's natural gas gathering systems.

Oil and natural gas revenues increased 20 percent due to a 25 percent increase in natural gas production and a 42 percent increase in oil production between 1995 and 1994. Average oil prices received by the Company increased 10 percent while average natural gas prices received by the Company decreased 13 percent. The average natural gas price declined due to a 11 percent reduction in average spot market prices received by the Company coupled with a 18 percent reduction in volumes produced from certain wells included under the Settlement Agreement which contains provisions for prices which were higher than spot market prices. The impact of higher prices received under the Settlement Agreement increased pre-tax income by approximately $1.6 and $1.8 million in 1995 and 1994, respectively.

In 1995, revenues from contract drilling operations increased by 19 percent as average rig utilization increased from 9.5 rigs operating in

1994 to 10.9 rigs operating in 1995. Daywork revenues represented 57 percent of total drilling revenues in 1995 and 58 percent in 1994. Turnkey and footage contracts typically provide for higher revenues since a greater portion of the expense of drilling the well is born by the drilling contractor.

Operating margins (revenues less operating costs) for the Company's oil and natural gas operations were 62 percent in 1995 compared to 66 percent in 1994. The reduction was primarily due to the decrease in prices received for the Company's natural gas production which offset increases in production between the two years. Margins were also reduced by the shutting in of production on certain natural gas properties in the months of February and March due to low spot market natural gas prices. Total operating costs increased 36 percent due to the additional costs associated with oil and natural gas production from new wells acquired and drilled in 1995 and 1994.

Operating margins for contract drilling decreased from 12 percent in 1994 to 11 percent in 1995. Margins in 1995 were limited by initial start up costs incurred in the first quarter of 1995 to establish rigs in the South Texas Basin and by unusually wet weather conditions during the second quarter of 1995 which delayed rig moves and depressed rig utilization. Total operating costs for contract drilling were up 21 percent in 1995 versus 1994 due to increased rig utilization and start up costs.

Contract drilling depreciation increased 28 percent in response to increased rig utilization. Depreciation, depletion and amortization ("DD&A") of oil and natural gas properties increased 23 percent as the Company increased its equivalent barrels of production by 28 percent. The Company's average DD&A rate per equivalent barrel declined from $4.08 in 1994 to $3.93 in 1995.

General and administrative expense increased 9 percent as certain employee costs, contract services and rental costs increased between the comparative years due to the continued growth of the Company's operations. Interest expense increased 96 percent as the average interest rate on the Company's outstanding bank debt increased from 7.15 percent in 1994 to 8.52 percent in 1995. Average bank debt outstanding in 1995 was $20.3 million higher than average bank debt outstanding in 1994 primarily due to the financing of producing property acquisition and developmental drilling as previously discussed.

The Company's effective income tax rate in 1995 and 1994 was significantly impacted by its net operating loss carryforwards. As of December 31, 1995, the Company's net operating loss and statutory depletion carryforwards had been fully recognized for financial reporting purposes, resulting in a net deferred tax asset of $530,000 at December 31, 1995.

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	As of December 31, 1996	1995
	(In thousands)	
Current Assets:		
Cash and cash equivalents	$ 547	$ 534
Accounts receivable (less allowance for doubtful accounts of $104 and $116)	15,842	10,398
Materials and supplies	2,302	2,048
Prepaid expenses and other	1,464	1,046
Total current assets	20,155	14,026
Property and Equipment:		
Drilling equipment	84,409	75,751
Oil and natural gas properties, on the full cost method	200,610	175,225
Transportation equipment	2,413	3,695
Other	6,485	6,100
	293,917	260,771
Less accumulated depreciation, depletion, amortization and impairment	176,211	164,752
Net property and equipment	117,706	96,019
Other Assets	132	877
Total Assets	$137,993	$110,922

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

LIABILITIES AND SHAREHOLDERS' EQUITY	As of December 31, 1996	1995
	(In thousands)	
Current Liabilities:		
Current portion of long-term debt	$ -	$ 20
Accounts payable	6,893	6,701
Accrued liabilities	4,516	3,976
Contract advances	1,300	410
Total current liabilities	12,709	11,107
Natural Gas Purchaser Prepayments (Note 4)	2,276	2,109
Long-Term Debt	40,600	41,100
Deferred Income Taxes	4,198	-
Commitments and Contingencies (Note 10)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	-	-
Common stock, $.20 par value, 40,000,000 shares authorized, 24,157,312 and 20,976,090 shares issued, respectively	4,831	4,195
Capital in excess of par value	62,735	50,181
Retained earnings (deficit)	10,751	2,418
Treasury stock, at cost (28,755 and 68,441 shares, respectively)	(107)	(188)
Total shareholders' equity	78,210	56,606
Total Liabilities and Shareholders' Equity	$ 137,993	$ 110,922

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 1996	1995	1994
Revenues:	(In thousands except per share amounts)		
Contract drilling	$28,819	$20,211	$16,952
Oil and natural gas	43,013	31,187	26,001
Other	238	1,676	942
Total revenues	72,070	53,074	43,895

Expenses:			
Contract drilling:			
Operating costs	24,259	18,041	14,909
Depreciation and impairment	2,944	2,596	2,030
Oil and natural gas:			
Operating costs	13,409	12,003	8,799
Depreciation, depletion and amortization	10,807	10,223	8,281
General and administrative	4,122	3,893	3,574
Interest	3,162	3,235	1,654
Total expenses	58,703	49,991	39,247
Income From Continuing Operations Before Income Taxes	13,367	3,083	4,648
Income Tax Expense (Benefit):			
Current	4	14	20
Deferred	5,030	(682)	-
Total income taxes	5,034	(668)	20
Income From Continuing Operations	8,333	3,751	4,628
Discontinued Operations:			
Income (loss) from operations of discontinued operations (net of income tax benefit of $69 in 1995)	-	(112)	166
Gain from sale of discontinued operations (net of income taxes of $221 in 1995)	-	360	-
Income from discontinued operations	-	248	166
Net Income	$ 8,333	$ 3,999	$ 4,794

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS - CONTINUED

	Year Ended December 31, 1996	1995	1994
	(In thousands except per share amounts)		
Earnings Per Common Share:			
Continuing operations:			
Primary	$ .37	$ .18	$ .22
Fully diluted	$ .36	$ .18	$ .22
Net income:			
Primary	$ .37	$ .19	$ .23
Fully diluted	$ .36	$ .19	$ .23
Weighted Average Shares Outstanding:			
Primary	22,708	21,210	20,900
Fully diluted	22,867	21,210	20,900

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, 1994, 1995 and 1996

	Common Stock	Capital In Excess Of Par Value	Retained Earnings (Deficit)	Treasury Stock	Total
		(In thousands)			
Balances, January 1, 1994	$ 4,172	$49,977	$ (6,375)	$ -	$47,774
Net income	-	-	4,794	-	4,794
Activity in employee compensation plans (48,685 shares)	10	109	-	-	119
Purchase of treasury stock (25,100 shares)	-	-	-	(80)	(80)
Balances, December 31, 1994	4,182	50,086	(1,581)	(80)	52,607
Net income	-	-	3,999	-	3,999
Activity in employee compensation plans (112,559 shares)	13	95	-	122	230
Purchase of treasury stock (90,000 shares)	-	-	-	(230)	(230)
Balances, December 31, 1995	4,195	50,181	2,418	(188)	56,606
Net income	-	-	8,333	-	8,333
Activity in employee compensation plans (321,667 shares)	64	615	-	123	802
Issuance of stock on exercise of warrants (2,859,555 shares)	572	11,939	-	-	12,511
Purchase of treasury stock (5,000 shares)	-	-	-	(42)	(42)
Balances, December 31, 1996	$ 4,831	$62,735	$ 10,751	$ (107)	$78,210

======== ======== ========= ======== ========

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, 1996	1995	1994
	(In thousands)		
Cash Flows From Operating Activities:			
Income from continuing operations	$ 8,333	$ 3,751	$ 4,628
Adjustments to reconcile income from continuing operations to net cash provided (used) by continuing operating activities:			
Depreciation, depletion, amortization and impairment	14,079	13,120	10,760
Gain on disposition of assets	(185)	(723)	(813)
Employee stock compensation plans	214	231	119
Bad debt expense	-	55	-
Deferred tax benefit	5,030	(682)	-
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(5,444)	(2,280)	94
Materials and supplies	(254)	(550)	(74)
Prepaid expenses and other	(418)	(94)	(396)
Accounts payable	(2,288)	(1,151)	(871)
Accrued liabilities	540	925	824
Contract advances	890	252	148
Natural gas purchaser prepayments	167	(1,620)	(1,858)
Net cash provided by continuing operating activities	20,664	11,234	12,561
Net cash flows from discontinued operations including changes in working capital	-	(259)	532
Net cash provided by operating activities	20,664	10,975	13,093

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, 1996	1995	1994
	(In thousands)		
Cash Flows From Investing Activities:			
Capital expenditures (including			

producing property acquisitions	$(34,111)	$(20,634)	$(28,227)
Proceeds from disposition of assets	1,009	4,613	2,038
Decrease in short-term investments	-	-	41
(Acquisition) disposition of other assets	215	-	141
Proceeds of sale of discontinued operations	-	369	-
Net cash used in investing activities	(32,887)	(15,652)	(26,007)
Cash Flows From Financing Activities:			
Borrowings under line of credit	31,500	39,700	63,700
Payments under line of credit	(32,000)	(35,900)	(51,300)
Payments on notes payable and other long-term debt	(20)	(1,000)	(480)
Proceeds from sale of common stock	12,798	-	-
Acquisition of treasury stock	(42)	(230)	(80)
Net cash provided by financing activities	12,236	2,570	11,840
Net Increase (Decrease) in Cash and Cash Equivalents	13	(2,107)	(1,074)
Cash and Cash Equivalents, Beginning of Year	534	2,641	3,715
Cash and Cash Equivalents, End of Year	$ 547	$ 534	$ 2,641
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest	$ 3,189	$ 3,214	$ 1,548
Income taxes	$ 63	$ -	$ 2

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 (the "Company"). The Company's investment in limited partnerships is accounted for on the proportionate consolidation method, whereby its share of the partnerships' assets, liabilities, revenues and expenses is included in the appropriate classification in the accompanying consolidated financial statements.

Nature of Business

The Company is engaged in the development, acquisition and production of oil and natural gas properties and the land contract drilling of oil and natural gas wells primarily in the Anadarko, Arkoma and South Texas Basins. These basins are located in Oklahoma, Texas, Kansas and Arkansas. Additional producing properties are located in Canada and other states, including New Mexico, Louisiana, North Dakota, Colorado, Wyoming, Montana, Alabama and Mississippi. The Company has an interest in 2,311 wells and serves as operator of 502 of those wells. Land contract drilling of oil and natural gas wells is performed for a wide range of customers using the 24 drilling rigs owned and operated by the Company.

Drilling Contracts

The Company accounts for "footage" and "turnkey" drilling contracts, in which the Company assumes the risks associated with drilling the well, under the completed-contract method and for "daywork" drilling contracts under the percentage-of-completion method. The entire amount of the 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" drilling contracts which are still in process.

Cash Equivalents and Short-Term Investments

The Company 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.

Property and Equipment

Drilling equipment, transportation equipment and other property and equipment are carried at cost. The Company provides for depreciation of drilling equipment on 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. At December 31, 1995, the Company elected to take three rigs out of service, and at that time, the three drilling rigs and certain other components of the rig fleet were written down by $254,000 to their estimated market value. The Company 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 the Company's property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets determined to be impaired based on estimated future net cash flows are reduced to estimated fair value. Changes in such estimates could cause the Company to reduce the carrying value of its 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.

Oil and Natural Gas Operations

The Company 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. The Company's determination of its oil and natural gas reserves are reviewed annually by independent petroleum engineers. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $3.90, $3.93 and $4.08 per equivalent barrel in 1996, 1995 and 1994, respectively. The Company's 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. 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 the Company's oil and natural gas properties. As discussed in Note 13, such estimates are imprecise. Changes in these estimates or declines in oil and natural gas prices could cause the Company in the near-term to reduce the carrying value of its oil and natural gas properties.

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 the Company has an interest or on properties in which a partnership, of which the Company is a general partner, has an interest. Accordingly, in 1994 the Company recorded $14,000 of contract drilling profits 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 1996 and 1995.

Limited Partnerships

The Company, through its wholly owned subsidiary, Unit Petroleum Company, is a general partner in twelve oil and natural gas limited partnerships sold privately and publicly. Certain of the Company's officers and directors own interests in some of these partnerships. Their interests were acquired generally on the same basis as other outside investors.

The Company shares in partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse the Company 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

The Company uses the sales method for recording natural gas sales. This method allows for recognition of revenue which may be more or less than the Company's share of pro-rata production from certain wells. Based upon the Company's 1996 average spot market natural gas price of $2.15 per Mcf, the Company estimates its balancing position to be approximately $6.4 million on under-produced properties and approximately $3.2 million on over-produced properties.

The Company's policy is to expense its pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the Company's balancing position on wells on which the Company has imbalances are not material.

Stock Based Compensation

The Company applies APB Opinion 25 in accounting for its stock option plans. 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 the Company's grants in 1996, 1995 and 1994 no compensation expense has been recognized. As allowed by Financial Accounting Standard No. 123 "Accounting for Stock-Based Compensation," the Company has disclosed the pro forma effects of recording compensation for such option grants based on fair value in Note 7 to the financial statements.

Self Insurance

The Company utilizes self insurance programs for employee group health and worker's compensation. Self insurance cost are accrued based upon the aggregate of estimated liabilities for reported claims and claims incurred but not yet reported.

Financial Instruments and Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trade receivables with a variety of national and international oil and natural gas companies. The Company 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 the Company's customer base. In addition, at December 31, 1996 and 1995, the Company had a concentration of cash of $2.6 million and $1.2 million, respectively, with one bank.

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.

NOTE 2 - DISCONTINUED OPERATIONS

On April 1, 1995, the Company's natural gas marketing operations were combined with a third party also involved in natural gas marketing activities forming GED Gas Services L.L.C. ("GED"). The combination was made to attain the increased volumes deemed necessary to profitably market third party natural gas. The Company owns a 34 percent interest in GED. On November 1, 1995 GED sold its natural gas marketing operation. This sale removed the Company from the third party natural gas marketing business. The gain on the sale was $360,000 net of income tax of $221,000.

The Company's former natural gas marketing activity has been presented as a discontinued operation. Summary results of operations data of the discontinued operations were as follows:

	For the Year Ended December 31, 1996	1995	1994
	(In Thousands)		
Results of Operations:			
Revenues attributable to discontinued operations	$ -	$13,548	$43,725
Expenses attributable to discontinued operations	-	13,729	43,559

Income (loss) attributable to discontinued operations before income taxes	-	(181)	166
Income tax benefit	-	69	-
Income (loss) attributable to discontinued operations	$ -	$ (112)	$ 166

NOTE 3 - WARRANTS

In 1987, the Company issued 2.873 million Units, consisting of three shares of the Company's common stock and one warrant, at a price of $10.375 per Unit. Each warrant entitled the holder to purchase one share of the Company's common stock at a price of $4.375. Prior to the warrants expiration on August 30, 1996, 2.86 million warrants were exercised providing $12.5 million in additional capital to the Company.

NOTE 4 - NATURAL GAS PURCHASER PREPAYMENTS

In March 1988, the Company entered into a settlement agreement with a natural gas purchaser. During early 1991, the Company and the natural gas purchaser superseded the original agreement with a new settlement agreement effective retroactively to January 1, 1991. Under these settlement agreements ("Settlement Agreement"), the Company has a prepayment balance of $2.3 million at December 31, 1996 representing proceeds received from the purchaser as prepayment for natural gas. This amount is net of natural gas recouped and net of certain amounts disbursed to other owners (such owners, collectively with the Company are referred to as the "Committed Interest") for their proportionate share of the prepayments. The December 31, 1996 prepayment balance is subject to recoupment in volumes of natural gas for a period ending the earlier of recoupment or December 31, 1997 (the "Recoupment Period"). During 1997, the purchaser is obligated to make monthly payments on behalf of the Committed Interest in an amount calculated as a percentage of the Committed Interest's share of the deliverability of the wells subject to the Settlement Agreement, up to a maximum of $156,000 or a minimum of $80,000 per month. At December 31, 1997, the Committed Interest's prepayment balance, if any, that has not been fully recouped in natural gas is subject to a cash repayment limited to a maximum of $3 million to be made in equal annual payments over a five year period with the first payment due June 1, 1998. The prepayment amounts subject to recoupment from future production by the purchaser are being recorded as liabilities and are reflected in revenues as recoupment occurs. The Company anticipates the maximum balance of $3 million will be unrecouped at December 31, 1997 and accordingly, the prepayment balance at December 31, 1996 is reported as a long-term liability. At the end of the Recoupment Period, the terms of the Settlement Agreement and the natural gas purchase contracts which are subject to the Settlement Agreement will terminate.

NOTE 5 - LONG-TERM DEBT

Long-term debt consisted of the following as of December 31, 1996 and 1995:

	1996	1995
	(In thousands)	
Revolving credit and term loan, with interest at December 31, 1996 and 1995 of 7.2 percent and 8.2 percent, respectively	$ 40,600	$ 41,100
Other	-	20
	40,600	41,120
Less current portion	-	20
Total long-term debt	$ 40,600	$ 41,100

At December 31, 1996, the Company's loan agreement ("Loan Agreement") provided for a total loan commitment of $75 million consisting of a revolving credit facility through August 1, 1999 and a term loan thereafter, maturing on August 1, 2003. Borrowings under the Loan Agreement are limited to a semi-annual borrowing base computation which as of December 31, 1996 is $52 million.

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 1.25 to 1.75 percent depending on the level of debt as a percentage of the total borrowing base. Subsequent to August 1, 1999, borrowings under the Loan Agreement bear interest at the Prime Rate plus .25 percent or the Libor rate plus 1.50 to 2.00 percent depending on the level of debt as a percentage of the total borrowing base.

At the Company'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 Company may not pay in part or in whole the outstanding principal balance of the note to which such Libor Rate option applies. Borrowings under the Prime Rate option may be paid anytime in part or in whole without premium or penalty.

A facility fee of 1/2 of 1 percent is charged for any unused portion of the borrowing base. Virtually all of the Company's drilling rigs are collateral for such indebtedness and the balance of the Company'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 the Company 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 the Company 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 the Company or any of its subsidiaries, except in favor of its banks. The Loan Agreement also requires that the Company maintain consolidated net worth of at least $48 million, a modified 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 to 1 and a ratio of total liabilities, as defined in the Loan Agreement, to consolidated tangible net worth not greater than 1.25 to 1. In addition, working capital provided by operations, as defined in the Loan Agreement, cannot be less than $12 million in any year.

Estimated annual principal payments under the terms of all long-term debt from 1997 through 2001 are $0, $0, $3,383,000, $10,150,000 and $10,150,000. Based on the borrowing rates currently available to the Company for debt with similar terms and maturities, long-term debt at December 31, 1996 approximates its fair value.

NOTE 6 - INCOME TAXES

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

	1996	1995	1994
	(In thousands)		
Income tax expense computed by applying the statutory rate	$ 4,545	$ 1,048	$ 1,580
Tax benefit of net operating loss carryforward	-	(1,730)	(1,595)
State income tax	499	-	6
Other	(10)	14	29
Income tax expense (benefit)	$ 5,034	$ (668)	$ 20

Deferred tax assets and liabilities are comprised of the following at December 31, 1996 and 1995:

	1996	1995
	(In thousands)	
Deferred tax assets:		
Allowance for losses	$ 443	$ 670
Net operating loss carryforwards	17,586	17,058
Statutory depletion carryforward	2,260	2,260
Investment tax credit carryforward	3,530	3,530
Gross deferred tax assets	23,819	23,518
Valuation allowance	(3,530)	(3,530)
Deferred tax liability-		
Depreciation, depletion and amortization	(24,487)	(19,458)
Net deferred tax asset (liability)	$ (4,198)	$ 530

The deferred tax asset valuation allowance reflects that the investment tax credit carryforwards above may not be utilized before the expiration dates as itemized below due in part to the effects of anticipated future exploratory and development drilling costs.

Realization of the deferred tax asset is dependent on generating sufficient taxable income prior to expiration of loss carryforwards. 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 during the carryforward period are reduced.

At December 31, 1996, the Company has net operating loss carryforwards for regular tax purposes of approximately $46,279,000 and net operating loss carryforwards for alternative minimum tax purposes of approximately $37,636,000 which expire in various amounts from 1999 to 2011. The Company has investment tax credit carryforwards of approximately $3,530,000 which expire from 1997 to 2000. In addition, a statutory depletion carryforward of approximately $5,948,000, which may be carried forward indefinitely, is available to reduce future taxable income, subject to statutory limitations.

NOTE 7 - 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, the Company's shareholders amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the Plan. Under the terms of the Plan, bonuses may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in annual installments subject to certain restrictions. No shares were issued under the Plan in 1996, 1995 or 1994.

At December 31, 1996, the Company also has a Stock Option Plan which provides for the granting of options for up to 1,500,000 shares of common stock to officers and employees. The 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. The exercise price for options granted to date was based on the fair market value 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, 1994	829,000	$ 2.04
Granted	102,500	3.00
Exercised	(16,000)	1.55
Outstanding at December 31, 1994	915,500	2.16
Granted	26,000	3.22
Exercised	(65,900)	1.65
Canceled	(10,000)	1.88

Outstanding at December 31, 1995	865,600	2.23
Granted	149,500	8.75
Exercised	(371,200)	1.59
Canceled	(7,100)	2.92
Outstanding at December 31, 1996	636,800	$ 4.13

OUTSTANDING OPTIONS

EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$1.50-$4.00	487,300	5 years	$2.72
$8.75	149,500	10 years	$8.75

EXERCISABLE OPTIONS

EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
$1.50-$4.00	375,000	$ 2.64
$8.75	-	$ -

Options for 375,000, 675,000 and 676,400 shares were exercisable with weighted average exercise prices of $2.64, $2.06 and $1.95 at December 31, 1996, 1995 and 1994, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). An aggregate of 100,000 shares of the Company's common stock may be issued upon exercise of the stock options. On the first business day following each annual meeting of stockholders of the Company, each person who is then a member of the Board of Directors of the Company and who is not then an employee of the Company or any of its subsidiaries will be granted an option to purchase 2,500 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, 1994	20,000	$ 2.75
Granted	10,000	2.88
Outstanding at December 31, 1994	30,000	2.79
Granted	12,500	3.38
Outstanding at December 31, 1995	42,500	2.96
Granted	12,500	6.88
Outstanding at December 31, 1996	55,000(1)	$ 3.85

- -------------

(1) All 55,000 options were exercisable at December 31, 1996.

The Company applies APB Opinion 25 in accounting for its Stock Option Plan and Non-Employee Director's Stock Option Plan. Accordingly, based on the nature of the Company's grants of options, no compensation cost has been recognized in 1996 and 1995. 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:

	1996	1995
Net Income (In thousands):		
As reported	$8,333	$3,999
Pro forma	$8,244	$3,971
Primary Earnings per Share:		
As reported	$ .37	$ .19

Pro forma	$ .36	$ .19
Fully Diluted Earnings per Share:		
As reported	$ .36	$ .19
Pro forma	$ .36	$ .19

The fair value of each option granted is estimated using the Black-Scholes model. The Company's volatility of stock was 0.51 based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 6.55 and 6.45 percent in 1996 and 1995, 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 within each grant. Fair value of options granted during 1996 and 1995 under the Stock Option Plan were $753,000 and $14,000, respectively, and under the Non-Employee Stock Option Plan were $56,000 and $27,000, respectively.

Under the Company'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. Each employee's contribution, up to a specified maximum, may be matched by the Company in full or on a partial basis. The Company made discretionary contributions under the plan of 44,686, 46,659 and 32,685 shares of common stock and recognized expense of $268,000, $174,000 and $130,000 in 1996, 1995 and 1994, respectively.

The Company 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 the Company's obligation under the Deferral Plan at December 31, 1996 and 1995 totaled $492,000 and $271,000 respectively. The Company recognizes payroll expense and records a liability at the time of deferral.

Effective January 1, 1997, the Company adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with the Company 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 week's salary for every whole year of service completed with the Company up to a maximum of 104 weeks. Benefits received under the Separation Plan will be reduced by the amount of any other benefits received from other disability or severance plans which may be in effect during the payment period. To receive payments the recipient must waive any claims against the Company in exchange for receiving the separation benefits. Benefits associated with this plan will begin to be recognized in 1997 for anticipated payments under the Separation Plan.

NOTE 8 - TRANSACTIONS WITH RELATED PARTIES

The Company formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 1996, with a subsidiary of the Company 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 the Company in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with the Company in most drilling operations and most producing property acquisitions commenced by the Company for its own account during the period from the formation of the Partnership through December 31 of each year.

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

	1996	1995	1994
	(In thousands)		
Contract drilling	$ 37	$ 34	$ 53
Well supervision and other fees	$ 349	$ 356	$ 226
General and administrative expense reimbursement	$ 105	$ 235	$ 209

A subsidiary of the Company paid the Partnerships, for which the Company or a subsidiary is the general partner, $31,000, $18,000 and $38,000 during the years ended December 31, 1996, 1995 and 1994, respectively, for purchases of natural gas production.

During 1996, 1995 and 1994 a bank owned by one of the Company's Directors was a participant in the Company's Loan Agreement. The bank's total pro rata share of the Company's line of credit is currently limited to an amount not to exceed $1.5 million.

NOTE 9 - SHAREHOLDER RIGHTS PLAN

The Company 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 the Company 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 the Company one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by the Company 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 the Company learns that an acquiring person (as defined in the Plan) has acquired 15 percent or more of the outstanding common stock of the Company 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. The Company 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 the Company 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 the Company.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

The Company leases office space under the terms of operating leases expiring through January 31, 2002. Future minimum rental payments under the terms of the leases are approximately $368,000, $348,000, $341,000, $93,000 and $70,000 in 1997, 1998, 1999, 2000, and 2001, respectively. Total rent expense incurred by the Company was $323,000, $307,000 and $210,000 in 1996, 1995 and 1994, respectively.

The Company had letters of credit supported by its Loan Agreement totaling $1,070,000 at December 31, 1996.

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 the Company 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. The Company made repurchases of $30,000, $34,000 and $38,000 in 1996, 1995 and 1994, respectively, for such limited partners' interests.

The Company is a party to various legal proceedings arising in the ordinary course of its business none of which, in the Company's opinion, will result in judgements which would have a material adverse effect on the Company.

NOTE 11 - INDUSTRY SEGMENT INFORMATION

The Company operates in the United States in two industry segments which are contract drilling and oil and natural gas exploration. The Company also has natural gas production in Canada which is not significant. Selected financial information by industry segment is as follows:

	Operating Revenues	Operating Profit (Loss)(1)	Total Assets(2)	Capital Expenditures	Depreciation, Depletion, Amortization and Impairment Expense
Year ended			(In thousands)		
December 31, 1996:					
Drilling	$ 28,819	$ 1,616	$ 24,500	$ 9,910	$ 2,944
Oil and					

natural gas	43,013	18,797	110,207	25,644	10,807
	71,832	$20,413	134,707	35,554	13,751
Other	238		3,286	989	328
Total	$ 72,070		$137,993	$ 36,543	$ 14,079
Year ended December 31, 1995:					
Drilling	$ 20,211	$ (426)	$ 15,449	$ 1,556	$ 2,596
Oil and natural gas	31,187	8,961	92,033	19,308	10,223
	51,398	$ 8,535	107,482	20,864	12,819
Other	1,676		3,440	1,089	301
Total	$ 53,074		$110,922	$ 21,953	$ 13,120
Year ended December 31, 1994:					
Drilling	$ 16,952	$ 13	$ 14,771	$ 1,115	$ 2,030
Oil and natural gas	26,001	8,921	83,082	25,110	8,281
	42,953	$ 8,934	97,853	26,225	10,311
Other	942		5,956	764	449
Discontinued operations	-		124	-	-
Total	$ 43,895		$103,933	$ 26,989	$ 10,760

(1) Operating profit is total operating revenues less operating expenses, depreciation, depletion, amortization and impairment and does not include non-operating revenues, general corporate expenses, interest expense, income taxes or gain from litigation settlement.

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

NOTE 12 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 1996 and 1995 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year ended December 31, 1996:				
Revenues	$ 15,871	$ 17,107	$ 17,286	$ 21,806
Gross profit(1)	$ 3,851	$ 4,376	$ 4,683	$ 7,503
Income before income taxes	$ 1,952	$ 2,529	$ 3,096	$ 5,790
Net Income	$ 1,219	$ 1,589	$ 1,899	$ 3,626
Earnings Per Common Share:				
Primary	$ .06	$ .07	$ .08	$ .15
Fully diluted	$ .06	$ .07	$ .08	$ .15

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year ended December 31, 1995:				
Revenues	$ 12,388	$ 11,505	$ 14,117	$ 15,064
Gross profit(1)	$ 1,875	$ 1,819	$ 1,721	$ 3,120
Income from continuing operations	$ 857(2)	$ 102	$ 916(3)	$ 1,876(4)
Income (loss) from discontinued operations	99	(81)	(35)	(95)
Gain from sale of discontinued operations	-	-	-	360
Net Income	$ 956(2)	$ 21	$ 881(3)	$ 2,141(4)
Earnings Per Common Share: (Both primary and fully diluted)				
Continuing operations	$ .05(2)	$ -	$ .04(3)	$ .09(4)
Discontinued operations	-	-	-	(.01)
Gain on sale of discontinued operations	-	-	-	.02
Net income	$ .05(2)	$ -	$ .04(3)	$ .10(4)

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

(2) Includes $635,000 gain on sale of natural gas compressors.

(3) Includes $850,000 gain from the settlement of litigation.

(4) Includes a net income tax benefit of $530,000.

NOTE 13 - OIL AND NATURAL GAS INFORMATION (UNAUDITED)

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

	USA	Canada	Total
	(In thousands)		
1996:			
Capitalized costs:			
Proved properties	$ 195,528	$ 480	$ 196,008
Unproved properties	4,602	-	4,602
	200,130	480	200,610
Less accumulated depreciation, depletion, amortization and impairment	102,463	389	102,852
Net capitalized costs	$ 97,667	$ 91	$ 97,758
Cost incurred:			
Unproved properties	$ 1,640	$ -	$ 1,640
Producing properties	2,338	-	2,338
Exploration	1,501	-	2,501
Development	20,150	15	20,165
Total costs incurred	$ 25,629	$ 15	$ 25,644
1995:			
Capitalized costs:			
Proved properties	$ 171,259	$ 465	$ 171,724
Unproved properties	3,501	-	3,501
	174,760	465	175,225
Less accumulated depreciation, depletion, amortization and impairment	91,739	379	92,118
Net capitalized costs	$ 83,021	$ 86	$ 83,107
Cost incurred:			
Unproved properties	$ 1,338	$ -	$ 1,338
Producing properties	9,183	-	9,183
Exploration	1,291	-	1,291
Development	7,486	10	7,496
Total costs incurred	$ 19,298	$ 10	$ 19,308

	USA	Canada	Total
	(In thousands)		
1994:			
Capitalized costs:			
Proved properties	$ 154,688	$ 455	$ 155,143
Unproved properties	2,250	-	2,250
	156,938	455	157,393
Less accumulated depreciation, depletion, amortization and impairment	81,583	368	81,951

Net capitalized costs	$ 75,355	$ 87	$ 75,442
Cost incurred:			
Unproved properties	$ 460	$ -	$ 460
Producing properties	13,108	-	13,108
Exploration	1,825	-	1,825
Development	9,716	1	9,717
Total costs incurred	$ 25,109	$ 1	$ 25,110

The results of operations for producing activities are provided below. Due to the Company's utilization of net operating loss carryforwards, income taxes were not significant and have not been included for the years 1995 and 1994.

	USA	Canada	Total
		(In thousands)	
1996:			
Revenues	$ 40,432	$ 60	$ 40,492
Production costs	11,195	14	11,209
Depreciation, depletion and amortization	10,723	11	10,734
	18,514	35	18,549
Income tax expense	6,986	15	7,001
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 11,528	$ 20	$ 11,548
1995:			
Revenues	$ 28,928	$ 53	$ 28,981
Production costs	9,914	16	9,930
Depreciation, depletion and amortization	10,156	11	10,167
Results of operations for producing activities before income taxes			

(excluding corporate overhead and financing costs)	$ 8,858	$ 26	$ 8,884
1994:			
Revenues	$ 23,964	$ 67	$ 24,031
Production costs	7,011	19	7,030
Depreciation, depletion and amortization	8,165	53	8,218
Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	$ 8,788	$ (5)	$ 8,783

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:

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
	(In thousands)					
1996:						
Proved developed and undeveloped reserves:						
Beginning of year	5,428	107,950	-	778	5,428	108,728
Revision of previous estimates	(387)	(3,822)	-	26	(387)	(3,796)
Extensions, discoveries and other additions	718	34,625	-	-	718	34,625
Purchases of minerals in place	67	3,036	-	-	67	3,036
Sales of minerals in place	(43)	(407)	-	-	(43)	(407)
Production	(579)	(12,974)	-	(51)	(579)	(13,025)
End of Year	5,204	128,408	-	753	5,204	129,161
Proved developed reserves:						
Beginning of year	4,697	94,975	-	350	4,697	95,325
End of year	4,509	107,536	-	326	4,509	107,862
1995:						
Proved developed and undeveloped reserves:						
Beginning of year	4,308	92,566	-	794	4,308	93,360
Revision of previous estimates	910	9,525	-	(10)	910	9,515
Extensions, discoveries and other additions	305	7,910	-	48	305	7,958
Purchases of minerals in place	500	10,892	-	-	500	10,892
Sales of minerals in place	(18)	(938)	-	-	(18)	(938)
Production	(577)	(12,005)	-	(54)	(577)	(12,059)
End of Year	5,428	107,950	-	778	5,428	108,728
Proved developed reserves:						
Beginning of year	3,521	80,110	-	359	3,521	80,469
End of year	4,697	94,975	-	350	4,697	95,325

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
1994:						
Proved developed and undeveloped reserves:						
Beginning of year	3,304	71,379	-	861	3,304	72,240
Revision of previous estimates	(97)	(571)	-	(14)	(97)	(585)
Extensions, discoveries and other additions	601	17,426	-	-	601	17,426
Purchases of minerals in place	910	14,075	-	-	910	14,075
Sales of minerals in place	(4)	(137)	-	-	(4)	(137)
Production	(406)	(9,606)	-	(53)	(406)	(9,659)
End of Year	4,308	92,566	-	794	4,308	93,360
Proved developed reserves:						
Beginning of year	3,187	65,395	-	426	3,187	65,821
End of year	3,521	80,110	-	359	3,521	80,469

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. The Company utilizes Ryder Scott Company, independent petroleum consultants, to review the Company's reserves as prepared by the Company's 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:

	USA	Canada	Total
		(In thousands)	
1996:			
Future cash flows	$626,945	$ 2,735	$629,680

Future production and development costs	171,749	339	172,088
Future income tax expenses	125,540	1,422	126,962
Future net cash flows	329,656	974	330,630
10% annual discount for estimated timing of cash flows	129,610	368	129,978
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$200,046	$ 606	$200,652
1995:			
Future cash flows	$320,916	$ 1,462	$322,378
Future production and development costs	107,830	304	108,134
Future income tax expenses	49,437	660	50,097
Future net cash flows	163,649	498	164,147
10% annual discount for estimated timing of cash flows	60,826	183	61,009
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$102,823	$ 315	$103,138
1994:			
Future cash flows	$234,171	$ 1,255	$235,426
Future production and development costs	105,876	311	106,187
Future income tax expenses	20,161	524	20,685
Future net cash flows	108,134	420	108,554
10% annual discount for estimated timing of cash flows	30,116	170	30,286
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 78,018	$ 250	$ 78,268

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

	USA	Canada	Total
	(In thousands)		
1996:			
Sales and transfers of oil and natural gas produced, net of production costs	$(29,237)	$ (46)	$(29,283)
Net changes in prices and production costs	92,541	738	93,279
Revisions in quantity estimates and changes in production timing	(13,390)	58	(13,332)
Extensions, discoveries and improved recovery, less related costs	69,942	-	69,942
Purchases of minerals in place	5,821	-	5,821
Sales of minerals in place	(514)	-	(514)
Accretion of discount	12,101	71	12,172
Net change in income taxes	(44,039)	(470)	(44,509)
Other - net	3,998	(60)	3,938
Net change	97,223	291	97,514
Beginning of year	102,823	315	103,138
End of year	$200,046	$ 606	$200,652
1995:			
Sales and transfers of oil and natural gas produced,			

	USA	Canada	Total
net of production costs	$(19,015)	$ (36)	$(19,051)
Net changes in prices and production costs	28,857	112	28,969
Revisions in quantity estimates and changes in production timing	(6,620)	(10)	(6,630)
Extensions, discoveries and improved recovery, less related costs	11,320	49	11,369
Purchases of minerals in place	11,897	-	11,897
Sales of minerals in place	(968)	-	(968)
Accretion of discount	8,447	54	8,501
Net change in income taxes	(11,727)	(105)	(11,832)
Other - net	2,614	1	2,615
Net change	24,805	65	24,870
Beginning of year	78,018	250	78,268
End of year	$102,823	$ 315	$103,138

	USA	Canada	Total
1994:			
Sales and transfers of oil and natural gas produced, net of production costs	$(16,953)	$ (48)	$(17,001)
Net changes in prices and production costs	(14,941)	206	(14,735)
Revisions in quantity estimates and changes in production timing	(482)	(5)	(487)
Extensions, discoveries and improved recovery, less related costs	17,050	-	17,050
Purchases of minerals in place	13,426	-	13,426
Sales of minerals in place	(138)	-	(138)
Accretion of discount	7,915	35	7,950
Net change in income taxes	(457)	(177)	(634)
Other - net	(554)	8	(546)
Net change	4,866	19	4,885
Beginning of year	73,152	231	73,383
End of year	$ 78,018	$ 250	$ 78,268

The Company'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 prices of oil and natural gas 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 the Company's properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to the Company'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.

As disclosed in Note 4, the Company is receiving payments from a natural gas purchaser which are subject to recoupment from future natural gas production. The amounts received will be reflected in revenues and the reserves and future net cash flows will be reduced as recoupment occurs.

In early 1997, the natural gas industry has experienced a downturn in natural gas prices. The Company's reserves were determined at December 31,1996 using a natural gas price of approximately $3.63 per Mcf for natural gas not subject to long-term contracts. During February 1997, the natural gas prices received by the Company fell to approximately $2.75 per Mcf for natural gas not subject to long-term contracts. This decrease in natural gas prices would have a significant effect on the SMOG value of the Company's reserves at December 31, 1996.

REPORT OF INDEPENDENT ACCOUNTANTS

The Shareholders and Board of Directors
Unit Corporation

We have audited the accompanying consolidated balance sheets of Unit Corporation and subsidiaries as of December 31, 1996 and 1995 and the related consolidated statements of operations, changes in shareholders' equity and cash flows and the related financial statement schedule for each of the three years in the period ended December 31, 1996. 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 in accordance with generally accepted auditing standards. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unit Corporation and subsidiaries as of December 31, 1996 and 1995, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1996 in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

COOPERS & LYBRAND L.L.P.

Tulsa, Oklahoma
February 18, 1997

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 executive officer of the Company. 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
King P. Kirchner	69	Chairman of the Board, Chief Executive Officer and Director
John G. Nikkel	62	President, Chief Operating Officer and Director

Earle Lamborn	62	Senior Vice President, Drilling and Director
Philip M. Keeley	55	Senior Vice President, Exploration and Production
Larry D. Pinkston	42	Vice President, Treasurer and Chief Financial Officer
Mark E. Schell	39	General Counsel and Secretary

____

Mr. Kirchner, a co-founder of the Company, has been the Chairman of the Board and a director since 1963 and was President until November 1983. Mr. Kirchner is a Registered Professional Engineer within the State of Oklahoma, having received degrees in Mechanical Engineering from Oklahoma State University and in Petroleum Engineering from the University of Oklahoma.

Mr. Nikkel joined the Company in 1983 as its President and a director. 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 40 years, joining the Company'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 the Company 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 serves as Executive Vice President and a director of that company. From 1977 until 1982, Mr. Keeley was employed by Cotton Petroleum Corporation, serving first as Manager of Land and from 1979 as Vice President and a director. Before joining Cotton, Mr. Keeley was employed for four years by Apexco, Inc. as Manager of Land and prior thereto he was employed by Texaco, Inc. for nine years. He received a Bachelor of Arts degree in Petroleum Land Management from the University of Oklahoma.

Mr. Pinkston joined the Company 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 the Company in January of 1987, as its Secretary and General Counsel. From 1979 until joining the Company, 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 the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1997 annual meeting of stockholders.

Item 11.Executive Compensation
- ---------------------------------

Information required by this item is incorporated by reference from the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1997 annual meeting of stockholders.

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

Information required by this item is incorporated by reference from the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1997 annual meeting of stockholders.

Item 13. Certain Relationships and Related Transactions
- ---

Information required by this item is incorporated by reference from the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1997 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, 1996 and 1995
- Consolidated Statements of Operations for the years ended December 31, 1996, 1995 and 1994
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 1996, 1995 and 1994
- Consolidated Statements of Cash Flows for the years ended December 31, 1996, 1995 and 1994
- 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, 1996, 1995 and 1994:
- Schedule II - Valuation and Qualifying Accounts and Reserves

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

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

3. Exhibits:

2 Certificate of Ownership and Merger of the Company and Unit Drilling Co., dated February 22, 1979 (filed as an Exhibit to the Company's Registration Statement No. 2-63702, which is incorporated herein by reference).

3.1.1 Certificate of Incorporation (filed as Exhibit 3.2 to the Company's Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).

3.1.2 Certificate of Amendment of Certificate of Incorporation dated July 21, 1988 (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1989, which is incorporated herein by reference).

3.1.3 Restated Certificate of Incorporation of Unit Corporation dated February 2, 1994 (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

3.2.1 By-Laws (filed as Exhibit 3.5 to the Company's Registration Statement of Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).

3.2.2 Amended and Restated By-Laws, dated June 29, 1988 (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1989, which is incorporated herein by reference).

4.2.1 Form of Warrant Agreement between the Company and the Warrant Agent (filed as Exhibit 4.1 to the Company's Registration statement on Form S-2 as S.E.C. File No. 33-16116, which is incorporated herein by reference).

4.2.2 Form of Warrant (filed as Exhibit 4.3 to the Company's Registration Statement of Form S-2 as S.E.C. File No. 33-16116, which is incorporated herein by reference).

4.2.3 Form of Common Stock Certificate (filed as Exhibit 4.2 on Form S-2 as S.E.C. File No. 33-16116, which is incorporated herein by reference).

4.2.4 First Amendment to Warrant Agreement (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended March 31, 1992, which is incorporated herein by reference).

4.2.5 Second Amendment to Warrant Agreement (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended March 31, 1994, which is incorporated herein by reference).

4.2.6 Rights Agreement dated as of May 19, 1995 between the Company and Chemical Bank, as Rights Agent (filed as Exhibit 1 to the Company's Form 8-A filed May 23, 1995, File No. 1-92601 and incorporated herein by reference).

10.1.14 Amended and Restated Credit Agreement dated as of January 17, 1992 by and between Unit Corporation and Bank of Oklahoma N.A., F&M Bank and Trust Company, Fourth National Bank of Tulsa and Western National Bank of Tulsa (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1991, which is incorporated herein by reference).

10.1.16 First Amendment to Amended and Restated Credit Agreement dated as of May 1, 1992, by and between Unit Corporation and Bank of Oklahoma, N.A., F&M Bank and Trust Company, Fourth National Bank of Tulsa, and Western National Bank of Tulsa (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended June 30, 1992, which is incorporated herein by reference).

10.1.17 Second Amendment to Amended and Restated Credit Agreement, dated March 3, 1993 and effective as of March 1, 1993, by and between Unit Corporation and Bank of Oklahoma, N.A., F&M Bank and Trust Company, Fourth National Bank of Tulsa, and Western National Bank of Tulsa (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended March 31, 1993, which is incorporated herein by reference).

10.1.18 Third Amendment to Amended and Restated Credit Agreement effective as of March 31, 1994, by and between Unit Corporation and Bank of Oklahoma, N.A., F&M Bank and Trust Company, Bank IV, Oklahoma, N.A. and American National Bank and Trust Company of Shawnee (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended March 31, 1994, which is incorporated herein by reference).

10.1.19 Fourth Amendment to Amended and Restated Credit Agreement dated as of December 12, 1994, by and between Unit Corporation and Bank of Oklahoma, N.A., F&M Bank and Trust Company, Bank IV, Oklahoma, N.A. and American National Bank and Trust Company of Shawnee (filed as an Exhibit in Form 8-K dated December 15, 1994, which is incorporated herein by reference).

10.1.20 Loan Agreement dated August 3, 1995 (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended June 30, 1995, which is incorporated herein by reference).

10.1.21 First Amendment to the Loan Agreement effective as of September 4, 1996, by and between Unit Corporation and Bank of Oklahoma, N.A., The First National Bank of Boston, Bank IV Oklahoma, N.A. and American National Bank and Trust Company of

Shawnee (filed as an Exhibit to the Company's Quarterly Report under cover of Form 10-Q for the quarter ended September 30, 1996, which is incorporated herein by reference).

10.1.22 Second Amendment to the Loan Agreement effective as of December 16, 1996 by and between Unit Corporation and Bank of Oklahoma,N.A., The First National Bank of Boston, Boatman's National Bank of Oklahoma and American National Bank and Trust Company of Shawnee (filed herewith).

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

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

10.2.11 Unit 1984 Employee Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Employee Oil and Gas Program's Registration Statement of Form S-1 as S.E.C. File No. 2-89678, which is incorporated herein by reference).

10.2.12 Unit 1985 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1985 Employee Oil and Gas Limited Partnership's Registration Statement on Form S-1 as S.E.C. File No. 2-95068, which is incorporated herein by reference).

10.2.13 Unit 1986 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit 10.11 to the Company's Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).

10.2.14 Unit 1987 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1989, which is incorporated herein by reference).

10.2.15 Unit 1988 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1989, which is incorporated herein by reference).

10.2.16 Unit 1989 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1989, which is incorporated herein by reference).

10.2.17 Unit 1990 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1990, which is incorporated herein by reference).

10.2.18 Unit 1991 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1991, which is incorporated herein by reference).

10.2.19 Unit 1992 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1992, which is incorporated herein by reference).

10.2.20 Unit 1993 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1992, which is incorporated herein by reference).

10.2.21* Unit Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).

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

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

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

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

10.2.26 Unit 1994 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

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

10.2.28 Unit 1995 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report, under cover of Form 10-K for the year ended December 31, 1994, which is incorporated herein by reference).

10.2.29 Unit 1996 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to the Company's Annual Report under cover of Form 10-K for the year ended December 31, 1995, which is incorporated herein by reference).

10.2.30* Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed herewith).

10.2.31 Unit 1997 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herewith).

10.5 Acquisition and Development Agreement, dated September 26, 1991, between Registrant and Municipal Energy Agency of Nebraska (filed as an Exhibit to Form 8-K dated September 30, 1991, which is incorporated herein by reference).

10.6 Purchase and Sale Agreement, dated May 22, 1992, between Esco Exploration, Inc. and Aleco Production Company (as "Seller") and Unit Petroleum Company (a "Buyer") and Helmerich & Payne, Inc. (a "Buyer") (filed as an Exhibit to Form 8-K dated May 21, 1992, which is incorporated herein by reference).

10.7 Asset Purchase Agreement, dated as of November 28, 1994, between the Registrant and Patrick Petroleum Corp of Michigan and American National Petroleum Company (filed as an Exhibit to Form 8-K dated December 15, 1994, which is incorporated herein by reference).

21 Subsidiaries of the Registrant (filed herewith).

23 Consent of Independent Accountants (filed herewith).

27 Financial Data Schedules (filed herewith).

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

(b) Reports on Form 8-K:

No reports on Form 8-K were filed during the quarter ended December 31, 1996.

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, 1996	$ 116	$ -	$ 12	$ 104
Year ended December 31, 1995	$ 289	$ 55	$ 228	$ 116
Year ended December 31, 1994	$ 411	$ -	$ 122	$ 289

Deferred Tax Asset Valuation Allowance:

Description	Balance at beginning of period	Additions	Deductions	Balance at end of period
		(In thousands)		
Year ended December 31, 1996	$ 3,530	$ -	$ -	$ 3,530
Year ended December 31, 1995	$ 6,423	$ -	$ 2,893	$ 3,530
Year ended December 31, 1994	$ 8,218	$ -	$ 1,795	$ 6,423

======== ======== ======== ========

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 17, 1997 By: /s/ John G. Nikkel

JOHN G. NIKKEL
President and Chief Operating 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 17th day of March, 1997.

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

EXHIBIT INDEX

Exhibit No.	Description	Page
10.1.22	Second Amendment to the Loan Agreement effective as of December 16, 1996 by and between Unit Corporation and Bank of Oklahoma, N.A., The First National Bank of Boston, Boatman's National Bank of Oklahoma and American National Bank and Trust Company of Shawnee.	
10.2.30	Separation Benefit Plan of Unit Corporation and Participating Subsidiaries.	
10.2.31	Unit 1997 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.	
21	Subsidiaries of the Registrant.	
23	Consent of Independent Accountants.	
27	Financial Data Schedule.	