

F O R M 1 0 - K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)

☒ 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, 1995

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	New York Stock Exchange
\$.20 per share	

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 in formation 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 13, 1996 - \$69,030,808

Number of Shares of Common Stock

Outstanding on March 13, 1996 - 21,009,635

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 1, 1996 are incorporated by reference in Part III.

Exhibit Index - See Page 72

FORM 10-K

UNIT CORPORATION

TABLE OF CONTENTS

PART I

Item 1.	Business.....	1
Item 2.	Properties.....	1
Item 3.	Legal Proceedings.....	17
Item 4.	Submission of Matters to a Vote of Security Holders..	17

PART II

Item 5.	Market for the Registrant's Common Equity and Related Stockholder Matters.....	18
Item 6.	Selected Financial Data.....	19
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations.....	20
Item 8.	Financial Statements and Supplementary Data.....	28
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.....	61

PART III

Item 10.	Directors and Executive Officers of the Registrant...	61
Item 11.	Executive Compensation.....	62
Item 12.	Security Ownership of Certain Beneficial Owners and Management.....	63
Item 13.	Certain Relationships and Related Transactions.....	63

PART IV

Item 14.	Exhibits, Financial Statement Schedules and Reports on Form 8-K.....	64
Signatures	71

UNIT CORPORATION

Annual Report

For The Year Ended December 31, 1995

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 a regional office in 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, 1995, the Company had 5,428 Mbbbls and 108,728 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, 1995, the Company had an

1

interest in a total of 2,570 wells in the United States and served as the operator of 482 wells. The Company also had an interest in 65 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:

Wells drilled: -----	Year Ended December 31,					
	1995		1994		1993	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:	-----	-----	-----	-----	-----	-----
Oil.....	-	-	-	-	-	-
Natural gas.....	-	-	1	.98	1	1.00
Dry.....	-	-	2	.80	1	0.10
	-----	-----	-----	-----	-----	-----
Total	-	-	3	1.78	2	1.10
	=====	=====	=====	=====	=====	=====
Development:						
Oil.....	15	4.70	5	5.00	12	11.98
Natural gas.....	26	7.02	40	13.46	25	11.12
Dry.....	6	2.27	12	7.26	8	4.29
	-----	-----	-----	-----	-----	-----
Total	47	13.99	57	25.72	45	27.39
	=====	=====	=====	=====	=====	=====

Oil and natural gas wells producing or capable of producing:

Oil - USA.....	750	207.80	675	177.68	337	162.09
Oil - Canada.....	-	-	-	-	-	-

Gas -USA.....	1,820	232.03	1,089	179.99	709	141.76
Gas - Canada.....	65	1.63	61	1.53	61	1.53
	-----	-----	-----	-----	-----	-----
Total	2,635	441.46	1,825	359.20	1,107	305.38
	=====	=====	=====	=====	=====	=====

2

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
	-----	-----	-----	-----
1995				

USA	548,674	117,403	24,810	12,866
Canada	31,360	784	-	-
	-----	-----	-----	-----
Total	580,034	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
	=====	=====	=====	=====
1993				

USA	246,115	86,013	28,738	18,021
Canada	31,360	784	-	-
	-----	-----	-----	-----
Total	277,475	86,797	28,738	18,021
	=====	=====	=====	=====

3

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,		
	1995	1994	1993
	-----	-----	-----
Average sales price per barrel of oil produced:			
USA	\$ 16.65	\$ 15.13	\$ 16.73
Canada	\$ -	\$ -	\$ -
Average sales price per Mcf of			

natural gas produced:			
USA	\$ 1.61	\$ 1.86	\$ 2.07
Canada	\$ 0.98	\$ 1.27	\$ 0.96
Oil production (Mbbbls):			
USA	577	406	397
Canada	-	-	-
	-----	-----	-----
Total	577	406	397
	=====	=====	=====
Natural gas production (MMcf):			
USA	12,005	9,606	7,435
Canada	54	53	70
	-----	-----	-----
Total	12,059	9,659	7,505
	=====	=====	=====
Average production expense per equivalent Mcf:			
USA	\$ 0.64	\$ 0.58	\$ 0.66
Canada	\$ 0.30	\$ 0.37	\$ 0.21

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,		
	1995	1994	1993
	-----	-----	-----
Oil (Mbbbls):			
USA	5,428	4,308	3,304
Canada	-	-	-
	-----	-----	-----
Total	5,428	4,308	3,304
	=====	=====	=====
Natural gas (MMcf):			
USA	107,950	92,566	71,379
Canada	778	794	861
	-----	-----	-----
Total	108,728	93,360	72,240
	=====	=====	=====

Further information relating to oil and natural gas operations is presented in Notes 1, 4, 10 and 12 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.

As of December 31, 1995, the Company owns 22 operational drilling rigs with rated depth capacities ranging from 8,000 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. 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 reaching the end of their useful life and the Company is increasing its drill pipe acquisitions to maintain current utilization levels. At December 31, 1995, the Company had orders for 75,000 feet of drill pipe of various grades scheduled for delivery through the first half of 1996. 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 equipment, drill pipe and qualified labor not only within the Company but in the industry as a whole.

5

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

	Year Ended December 31,				
	1995	1994	1993	1992	1991
	----	----	----	----	----
Number of operational rigs owned at end of period	22	25	25	26	26
Average number of rigs utilized(1)	10.9	9.5	8.0	5.5	9.1
Number of wells drilled	111	95	84	56	92
Total footage drilled (feet in 1000's)	1,196	1,027	788	527	736

- -----

(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 13, 1996, 14 of the Company's 22 drilling rigs were operating under contract.

The following table sets forth, as of March 13, 1996, the type and approximate depth capability of each of the Company's drilling rigs:

Type	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-75.....	15,000
BDW 1350-M.....	20,000
SU-15 North Texas Machine.....	12,000
SU-15 North Texas Machine.....	12,000
National 110-E.....	20,000
Continental Emsco C-1-E.....	20,000
Gardner Denver 1500-E.....	25,000

6

For the past several years, the Company's contract drilling services have encountered significant competition due to depressed levels of activity in contract drilling. While the Company's drilling operations showed improvement in 1995, this competition 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 1995 turnkey revenue represented approximately 17 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, 1995, 10 contract drilling customers accounted for approximately 19 percent of the Company's total revenues and approximately 1 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.

7

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

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 has been accounted for as a discontinued operation and accordingly, the 1995 and prior year financial information has been 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.

8

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 7 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.

9

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 13, 1996, the Company had approximately 225 employees in its land contract drilling operations, 64 employees in its oil and natural gas operations and 23 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

10

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.

11

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-not ice 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. However, due to the still 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.

12

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.

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.

FACTORS INFLUENCING PROJECTIONS OF FUTURE 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, 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.

As with any forward- looking statement, these 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

14

following discussion outlines certain factors that in the future could affect the Company's consolidated results for 1996 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. 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, 1995, 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 of \$1,100,000 and \$535,000, respectively. During 1995, 95% 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 can 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

15

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, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to acquire a large producing property package or the need to replace a costly rig component due to an unexpected loss, which could force 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.

16

Item 3. Legal Proceeding

- -----

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, 1995.

PART II

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

Matters

As of February 21, 1996, the Company had 3,225 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:

QUARTER -----	1995		1994	
	High	Low	High	Low
First	\$3 1/4	\$2 1/2	\$3 1/2	\$2 5/8
Second	\$3 7/8	\$2 7/8	\$3 1/4	\$2 3/4
Third	\$4 1/4	\$3 1/4	\$3 1/2	\$2 5/8
Fourth	\$4 3/4	\$3 1/2	\$3 7/8	\$2 5/8

Item 6. Selected Financial Data

	Year Ended December 31,				
	1995	1994	1993	1992	1991
	-----	-----	-----	-----	-----
	(In thousands except per share amounts)				
Revenues	\$53,074	\$43,895	\$38,682	\$33,744	\$40,232
	=====	=====	=====	=====	=====
Income From Continuing Operations	\$ 3,751	\$ 4,628	\$ 3,937	\$ 1,631	\$ 4,164
	=====	=====	=====	=====	=====
Net Income	\$ 3,999 (1)	\$ 4,794 (2)	\$ 3,871	\$ 1,087 (3)	\$ 4,341
	=====	=====	=====	=====	=====
Net Income Per Common Share:					
Continued	\$.18	\$.22	\$.19	\$.08	\$.20
	=====	=====	=====	=====	=====
Net Income	\$.19 (1)	\$.23 (2)	\$.19	\$.05 (3)	\$.21
	=====	=====	=====	=====	=====
Total Assets	\$110,922	\$103,933	\$ 88,816	\$ 83,960	\$ 84,972
	=====	=====	=====	=====	=====
Long-Term Debt	\$ 41,100	\$ 37,824	\$ 25,919	\$ 22,298	\$ 23,153
	=====	=====	=====	=====	=====
Long-Term Portion of Natural Gas Purchaser Prepayments	\$ 2,109	\$ 2,149	\$ 4,417	\$ 5,924	\$ 7,626
	=====	=====	=====	=====	=====
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 1995, 1994 and 1993 activity.

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

Results of Operations

Financial Condition and Liquidity

The Company currently has a loan agreement ("Loan Agreement"), which provides for a total commitment of \$75 million, consisting of a revolving credit facility through August 31, 1997 and a term loan thereafter, maturing on August 31, 2001. 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 \$50 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, 1995, borrowings under the Loan Agreement totaled \$41.1 million. At February 21, 1996, borrowings under the Loan Agreement totaled \$40.9 million with \$7.9 million available for future borrowings. The average interest rate on the bank debt was 8.2 and 7.6 percent at December 31, 1995 and February 21, 1996, 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 ("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, 1995 and February 21, 1996, \$38.0 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, 1995 was \$56.6 million, making the Company's ratio of long-term debt-to-equity .73 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 1995 was \$11.2 million as compared to \$12.6 million in 1994.

The Company's capital expenditures during 1995 were \$22.0 million. The majority of the capital expenditures, \$19.3 million, were made in the Company's oil and natural gas operations with \$8.8 million and \$9.2

20

million used for exploration and development drilling and producing property acquisitions, respectively. Capital expenditures made by the Company's contract drilling operations were approximately \$1.6 million in 1995 and principally consisted of drill pipe and drill collar expenditures along with improvements to large rig components which benefit current and future years. The Company's rigs are composed of large components some of which, on a rotational basis, are required to be overhauled to assure proper performance. Such capital expenditures will continue in future years. Additional expenditures of approximately \$2 million will be required in 1996 for drill pipe as certain grades of the Company's drill pipe are reaching the end of their useful life.

During 1996, the Company's oil and natural gas segment plans to focus on its developmental drilling program as early 1996 natural gas prices have improved lessening the availability of economical producing property acquisitions. The Company's capital expenditures are discretionary and directed toward increasing reserves and future growth. Current operations should not be adversely affected by any inability 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 \$20 million on its capital expenditure program in 1996.

The Company has 2.873 million warrants outstanding. The warrants entitle the holders to purchase one share of common stock at a price of \$4.375 per share. The warrants, subject to certain restrictions, are callable by the Company, in whole or in part, at \$.50 per warrant. A Second Amendment to the Warrant Agreement between the Company and the Warrant Agent, dated May 9, 1994, extended the term of the warrants to August 30, 1996.

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, 1995 prepayment balance of \$2.1 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"). Additionally, 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 \$180,000 or a minimum of \$90,000 per month for the year 1996. Both the maximum and minimum monthly payments decline annually through the Recoupment Period. 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

21

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 1996. 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. Under the Settlement Agreement, the purchaser is entitled to make a monthly determination of the volumes to be purchased from the wells subject to the Settlement Agreement. During 1994 and the first nine months of 1995 natural gas delivered was approximately 75 percent of the deliverability of the wells subject to the Settlement Agreement. Pursuant to the terms of the Settlement Agreement, the purchaser notified the Company that effective October 1, 1995, the purchaser plans to make seasonal takes of natural gas by requesting the maximum deliverability subject to the Settlement Agreement in certain months and no deliverability in other months. For the majority of the fourth quarter of 1995 and continuing into the first quarter of 1996 the purchaser has requested the maximum deliverability subject to the Settlement Agreement. Because these month-to-month determinations, up to certain maximum levels, are made by the purchaser, the Company is unable to predict with certainty future natural gas sales from these wells. In addition, future revenues to be received by the Company would be impacted by the failure of the purchaser to meet its obligations, financially or otherwise, under the terms of the Settlement Agreement or by the ability of the wells to maintain certain projected deliverability requirements. In the event the wells are unable to maintain such deliverability, the monthly payments to be received by the Company under the Settlement Agreement would be decreased. 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 \$1.6, \$1.8 and \$1.9 million in 1995, 1994 and 1993, respectively.

Oil prices received by the Company in 1995 ranged from an average of \$15.33 in July to \$18.14 in December. The Company's average price for oil received in 1995 was \$16.65. Natural gas prices received by the Company in 1995 ranged from an average of \$1.35 in March to \$2.01 in December. Average natural gas prices received by the Company remained volatile throughout 1995 and averaged \$1.61 f or the year as a whole. 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 large drop in spot market natural gas prices will have a significant adverse effect on the value of the Company's reserves and 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 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.

22

The Company's ability to utilize its full complement of drilling rigs, should economic conditions improve in the future, will be limited 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 1996.

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, 115,100 shares have been repurchased at prices ranging from \$2 1/2 to \$3 3/8 per share. During the first quarter of 1995, 46,659 of the purchased shares were reissued as the Company's matching contribution to its 401(k) Employee Thrift Plan. At December 31, 1995, 68,441 treasury shares were held by the Company.

The Company's wholly owned natural gas marketing subsidiary, Mountain Front Pipeline Company, achieved substantial growth in revenues during previous years, but did not achieve the size necessary to reach desired levels of profitability. Consequently, 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 has been accounted for as a discontinued operation and accordingly, the 1995 and prior year financial information has been restated to reflect this treatment.

Effects of Inflation

- -----

The effects of inflation on the Company's current operations have been minimal due to low inflation rates. However, the impact of inflation on the Company in the future will depend on the relative increase, if any, the Company may realize in its rig rates and the selling price of its oil and natural gas. If industry activity increases substantially, shortages in support equipment such as drill pipe, third party services and qualified labor would occur resulting in 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

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 current economic conditions do 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. The disposition of the Company's involvement in third party natural gas marketing does not adversely affect the operation of the Company's drilling and oil and natural gas exploration operations or the profitability of the Company as a whole. 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 are higher than current 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.

In 1994, the Company moved two of its rigs under multi-well contracts to the South Texas Basin creating a new operating region for the Company's drilling

24

services and helping to further improve its rig utilization. In the fourth quarter of 1995, the contract drilling operations opened an office in Houston, Texas with plans to further develop this new market area. At December 31, 1995, four of the Company's 22 rigs were located in the South Texas Basin.

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. This increase is expected to continue in 1996 as the Company expands its 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 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 have been fully recognized for financial reporting purposes, resulting in a net deferred tax asset of \$530,000. Realization is dependent on generating sufficient taxable income prior to expiration of net operating loss carryforwards. Although realization is not assured, management believes it is more likely than not that all of 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.

25

1994 versus 1993
- -----

Net income for 1994 was \$4,794,000, compared with \$3,871,000 in 1993. The increase in net income was achieved through improved operating results in the Company's contract drilling segment and also from a net gain of \$742,000 recognized in conjunction with the sale of one of the Company's gas gathering systems. Total revenues from continuing operations were

\$43,895,000 in 1994 and \$38,682,000 in 1993.

Oil and natural gas revenues increased 8 percent due to a 29 percent increase in natural gas production and a 2 percent increase in oil production between 1994 and 1993. Average natural gas and oil prices received by the Company both decreased 10 percent partially offsetting the increases in production. Average natural gas prices received by the Company declined due to a 14 percent reduction in average spot market prices coupled with a 14 percent reduction in volumes produced from certain wells included under the Settlement Agreement which contains provisions for prices which are higher than current spot market prices. The impact of the higher price received under the Settlement Agreement increased pre-tax income by approximately \$1.8 and \$1.9 million in 1994 and 1993, respectively.

In 1994, revenues from contract drilling operations increased by 16 percent as average rig utilization increased from 8 rigs in 1993 to 9.5 rigs in 1994. Daywork revenues represented 58 percent of total drilling revenues in 1994 as opposed to 47 percent in 1993. 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) were either slightly improved or unchanged for all segments on the Company's operations when comparing 1994 with 1993. Operating margins for the Company's oil and natural gas operations were unchanged due primarily to increased production offset by the decrease in average prices received for oil and natural gas. Total operating costs from oil and natural gas operations increased 9 percent as the Company increased production from reserves added primarily through development drilling in 1993 and 1994.

Operating margins for contract drilling improved from 10 percent in 1993 to 12 percent in 1994. Increased rig utilization helped provide greater revenue in relation to fixed costs. Total operating costs for contract drilling were up 12 percent in 1994 versus 1993 due to the increased utilization.

Contract drilling depreciation increased 19 percent in response to increased rig utilization. Depreciation, depletion and amortization ("DD&A") of oil and natural gas properties increased 18 percent as the Company increased its equivalent barrels of production by 22 percent. The Company's average DD&A rate per equivalent barrel declined from \$4.13 in 1993 to \$4.08 in 1994.

26

General and administrative expense increased 8 percent as certain employee and reporting costs increased between the comparative years. Interest expense increased 25 percent as the average interest rate on the Company's outstanding bank debt increased from 6 percent in 1993 to 7.15 percent in 1994. Outstanding bank debt was \$12.4 million higher at December 31, 1994 when compared with December 31, 1993 due to the financing of the December 15, 1994 Patrick acquisition.

IMPACT OF FINANCIAL ACCOUNTING PRONOUNCEMENTS

In March 1995, Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of" was issued. The statement establishes accounting standards for the impairment of long-lived assets, such as the Company's drilling, transportation and other equipment and will be effective for the Company beginning with the year ending December 31, 1996. The Company does not believe the new standard will have a material effect on the Company's financial position or results of operations.

In October 1995, Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" was issued. The statement requires the computation of compensation for grants of stock, stock options and other equity instruments issued to employees based on fair value. The compensation calculated is to be either recorded as an expense in the financial statements or, alternatively, disclosed. The Company anticipates it will elect the disclosure method of complying with the new standard. Under existing accounting rules, the Company's stock option grants have not resulted in compensation expense. Accordingly, under the provisions of the new statement, pro forma net income to be disclosed will be lower than net income reported in the financial statements.

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	As of December 31,	
	1995	1994
	-----	-----
	(In thousands)	
Current Assets:		
Cash and cash equivalents	\$ 534	\$ 2,641
Accounts receivable (less allowance for doubtful accounts of \$116 and \$289)	10,398	8,173
Materials and supplies	2,048	1,498
Prepaid expenses and other	1,046	952
	-----	-----
Total current assets	14,026	13,264
	-----	-----
Net Assets of Discontinued Operations	-	124
	-----	-----
Property and Equipment:		
Drilling equipment	75,751	75,746
Oil and natural gas properties, on the full cost method	175,225	157,393
Transportation equipment	3,695	3,341
Other	6,100	7,858
	-----	-----
	260,771	244,338
Less accumulated depreciation, depletion, amortization and impairment	164,752	153,833
	-----	-----
Net property and equipment	96,019	90,505
	-----	-----
Other Assets	877	40
	-----	-----
Total Assets	\$110,922	\$103,933
	=====	=====

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

LIABILITIES AND SHAREHOLDERS' EQUITY	As of December 31,	
	1995	1994
	-----	-----
	(In thousands)	
Current Liabilities:		
Current portion of long-term debt	\$ 20	\$ 496
Current portion of natural gas purchaser prepayments (Note 4)	-	1,580
Accounts payable	6,701	6,068
Accrued liabilities	3,976	3,051
Contract advances	410	158
	-----	-----
Total current liabilities	11,107	11,353
	-----	-----
Natural Gas Purchaser Prepayments (Note 4)	2,109	2,149
	-----	-----
Long-Term Debt	41,100	37,824
	-----	-----
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, \$1.00 par value, 5,000,000 shares authorized, none issued	-	-
Common stock, \$.20 par value, 40,000,000 shares authorized, 20,976,090 and 20,910,190 shares issued, respectively	4,195	4,182
Capital in excess of par value	50,181	50,086
Retained earnings (deficit)	2,418	(1,581)
Treasury stock, at cost (68,441 and 25,100 shares, respectively)	(188)	(80)
	-----	-----
Total shareholders' equity	56,606	52,607
	-----	-----
Total Liabilities and Shareholders' Equity	\$ 110,922	\$ 103,933
	=====	=====

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	1995	1994	1993
	-----	-----	-----
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	\$20,211	\$16,952	\$14,676
Oil and natural gas	31,187	26,001	24,073
Other	1,676	942	(67)
	-----	-----	-----
Total revenues	53,074	43,895	38,682
Expenses:	-----	-----	-----
Contract drilling:			
Operating costs	18,041	14,909	13,269
Depreciation and impairment	2,596	2,030	1,713
Oil and natural gas:			
Operating costs	12,003	8,799	8,098
Depreciation, depletion and amortization	10,223	8,281	7,018
General and administrative	3,893	3,574	3,302
Interest	3,235	1,654	1,324
	-----	-----	-----
Total expenses	49,991	39,247	34,724
	-----	-----	-----
Income From Continuing Operations			
Before Income Taxes	3,083	4,648	3,958
Income Tax Expense (Benefit)	(668)	20	21
	-----	-----	-----
Income From Continuing Operations	3,751	4,628	3,937

Discontinued Operations:			
Income (loss) from operations of discontinued operations (net of income taxes of \$69 in 1995)	(112)	166	(66)
Gain from sale of discontinued operations (net of income taxes of \$221 in 1995)	360	-	-
Income(loss) from discontinued operations	248	166	(66)
Net Income	\$ 3,999	\$ 4,794	\$ 3,871
Net Earnings Per Common Share:			
Continuing operations	\$.18	\$.22	\$.19
Net income	\$.19	\$.23	\$.19
Weighted Average Shares Outstanding (Both Primary and Fully Diluted)	21,210	20,900	20,860

The accompanying notes are an integral part of the consolidated financial statements
30

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 1993, 1994 and 1995

	Common Stock	Capital In Excess Of Par Value	Retained Earnings (Deficit)	Treasury Stock	Total
	-----	-----	-----	-----	-----
(In thousands)					
Balances, January 1, 1993	\$ 4,157	\$49,841	\$(10,246)	\$ -	\$43,752
Net income	-	-	3,871	-	3,871
Activity in employee compensation plans (78,706 shares)	15	136	-	-	151
	-----	-----	-----	-----	-----
Balances, December 31, 1993	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

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,		
	1995	1994	1993
	-----	-----	-----
	(In thousands)		
Cash Flows From Operating Activities:			
Income from continuing operations	\$ 3,751	\$ 4,628	\$ 3,937
Adjustments to reconcile income from continuing operations to net cash provided (used) by continuing operating activities:			
Depreciation, depletion, amortization and impairment	13,120	10,760	9,243
Gain on disposition of assets	(723)	(813)	(49)
Employee stock compensation plans	231	119	151
Bad debt expense	55	-	-
Deferred tax benefit	(682)	-	-
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(2,280)	94	428
Materials and supplies	(550)	(74)	(99)
Prepaid expenses and other	(94)	(396)	318
Accounts payable	(1,151)	(871)	(1,632)
Accrued liabilities	925	824	(877)
Contract advances	252	148	8
Natural gas purchaser prepayments	(1,620)	(1,858)	(1,743)
	-----	-----	-----
Net cash provided by continuing operating activities	11,234	12,561	9,685
	-----	-----	-----
Net cash flows provided by discontinued operations including changes in working capital	(259)	532	182
	-----	-----	-----
Net cash provided by operating activities	10,975	13,093	9,867
	-----	-----	-----

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,		
	1995	1994	1993
	-----	-----	-----
	(In thousands)		
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions)	\$ (20,634)	\$ (28,227)	\$ (11,946)
Proceeds from disposition of assets	4,613	2,038	709
Decrease in short-term investments	-	41	664
(Acquisition) disposition of other assets	-	141	(45)
Proceeds of sale of discontinued operations	369	-	-
	-----	-----	-----
Net cash used in investing activities	(15,652)	(26,007)	(10,618)
	-----	-----	-----
Cash Flows From Financing Activities:			
Borrowings under line of credit	39,700	63,700	43,400
Payments under line of credit	(35,900)	(51,300)	(40,600)
Proceeds from notes payable and other long-term debt	-	-	911

Payments on notes payable and other long-term debt	(1,000)	(480)	(367)
Acquisition of treasury stock	(230)	(80)	-
	-----	-----	-----
Net cash provided by financing activities	2,570	11,840	3,344
	-----	-----	-----
Net Increase (Decrease) in Cash and Cash Equivalents	(2,107)	(1,074)	2,593
Cash and Cash Equivalents, Beginning of Year	2,641	3,715	1,122
	-----	-----	-----
Cash and Cash Equivalents, End of Year	<u>\$ 534</u>	<u>\$ 2,641</u>	<u>\$ 3,715</u>

Supplemental Disclosure of Cash Flow Information:

Cash paid during the year for:

Interest	\$ 3,214	\$ 1,548	\$ 1,326
Income taxes	\$ -	\$ 2	\$ 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 2,635 wells and serves as operator of 482 of those wells. Land contract drilling of oil and natural gas wells is performed for a wide range of customers with the 22 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

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, which 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 drilling rigs is evaluated utilizing estimated future net cash flows from utilization of the Company rigs. Changes in these estimates could cause the Company to reduce the carrying value of its rigs.

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 \$3.93, \$4.08 and \$4.13 per equivalent barrel in 1995, 1994 and 1993, 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 12, 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 1995 and 1993.

Limited Partnerships

The Company, through its wholly owned subsidiary, Unit Petroleum Company, is a general partner in eleven 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 1995 average spot market natural gas price of \$1.47 per Mcf, the Company estimates its balancing position to be approximately \$4.5 million on under-produced properties and approximately \$2.7 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.

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

36

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, 1995 and 1994, the Company had a concentration of cash of \$1.2 and \$2.3 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.

Impact of Financial Accounting Pronouncements

In March 1995, Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of" was issued. The statement establishes accounting standards for the impairment of long-lived assets, such as the Company's drilling, transportation and other equipment and will be effective for the Company beginning with the year ending December 31, 1996. The Company does not believe the new standard will have a material effect on the Company's financial position or results of operations.

In October 1995, Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" was issued. The statement requires the computation of compensation for grants of stock, stock options and other equity instruments issued to employees based on fair value. The compensation calculated is to be either recorded as an expense in the financial statements or, alternatively, disclosed. The Company anticipates it will elect the disclosure method of complying with the new standard. Under existing accounting rules, the Company's stock option grants have not resulted in compensation expense. Accordingly, under the provisions of the new statement, pro forma net income to be disclosed will be lower than net income reported in the financial statements.

Reclassifications

Certain reclassifications have been made in the 1993 and 1994 consolidated financial statements to conform them to classifications used in 1995.

On April 1, 1995, the Company's natural gas marketing operations were combined with a third party also involved in natural gas marketing activities into a business combination forming GED Gas Services L.L.C. ("GED"). The combination was made to attain the increased volumes deemed necessary to

37

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. Prior years have been restated to present the Company's former natural gas marketing activity as a discontinued operation.

Summary results of operations and financial position data of the discontinued operations were as follows:

	For the Year Ended December 31,		
	1995	1994	1993
	-----	-----	-----
	(In Thousands)		
Results of Operations:			
Revenues attributable to discontinued operations	\$13,548	\$43,725	\$31,636
Expenses attributable to discontinued operations	13,729	43,559	31,702
	-----	-----	-----
Income (loss) attributable to discontinued operations before income taxes	(181)	166	(66)
Income tax benefit	69	-	-
	-----	-----	-----
Income (loss) attributable to discontinued operations	\$ (112)	\$ 166	\$ (66)
	=====	=====	=====
	December 31,		
	1995	1994	
	-----	-----	
	(In Thousands)		
Financial Position:			
Current assets	\$ -	\$ 8,574	
Net property plant and equipment	-	38	
Current liabilities	-	(8,488)	
	-----	-----	
Net assets of discontinued operations	\$ -	\$ 124	
	=====	=====	

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 entitles the holder to purchase one share of the Company's

38

common stock at a price of \$4.375 anytime prior to the warrant's expiration on August 30, 1996. The warrants, subject to certain restrictions, are callable by the Company, in whole or in part, at \$.50 per warrant. As of December 31, 1995 no warrants have been exercised.

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 \$2.1 million at December 31, 1995 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, 1995 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"). Additionally, 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 \$180,000 or a minimum of \$90,000 per month for the year 1996. Both the maximum and minimum monthly payments decline annually through the Recoupment Period. 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 portion of the prepayments that are estimated to be recouped in the next twelve months has been included in current liabilities. The Company anticipates the maximum balance of \$3 million will be unrecouped at December 31, 1997. 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, 1995 and 1994:

	1995	1994
	-----	-----
Revolving credit and term loan, with interest at December 31, 1995 and 1994 of 8.2 percent and 8.5 percent, respectively	\$ 41,100	\$ 37,300
Other	20	1,020
	-----	-----
	41,120	38,320
Less current portion	20	496
	-----	-----
Total long-term debt	<u>\$ 41,100</u>	<u>\$ 37,824</u>

At December 31, 1995, the Company's loan agreement ("Loan Agreement") provided for a total loan commitment of \$75 million consisting of a revolving credit facility through August 31, 1997 and a term loan thereafter, maturing on August 31, 2001. Borrowings under the Loan Agreement are limited to a semi-annual borrowing base computation which as of December 31, 1995 is \$50 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 1.75 to 2.25 percent depending on the level of debt as a percentage of the total borrowing base. Subsequent to August 1, 1997, borrowings under the Loan Agreement bear interest at the Prime Rate plus .25 percent or the Libor rate plus 2.00 to 2.50 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 1/2 of 1 percent facility fee 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

40

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 1996 through 2000 are \$20,000, \$3,425,000, \$10,275,000, \$10,275,000 and \$10,275,000. Based on the borrowing rates currently available to the Company for debt with similar terms and maturities, long-term debt at December 31, 1995 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:

	1995	1994	1993
	-----	-----	-----
	(In thousands)		
Income tax expense computed by applying the statutory rate	\$ 1,048	\$ 1,580	\$ 1,346
Tax benefit of net operating loss carryforward	(1,730)	(1,595)	(1,331)
State income tax	-	6	1
Other	14	29	5
	-----	-----	-----
Income tax expense (benefit)	\$ (668)	\$ 20	\$ 21
	=====	=====	=====

41

Deferred tax assets and liabilities are comprised of the following at December 31, 1995 and 1994:

	1995	1994
	-----	-----
Deferred tax assets:	(In thousands)	
Allowance for losses	\$ 670	\$ 521
Net operating loss carryforwards	17,058	18,190
Statutory depletion carryforward	2,260	2,500
Investment tax credit carryforward	3,530	3,530
	-----	-----
Gross deferred tax assets	23,518	24,741
Valuation allowance	(3,530)	(6,423)

Deferred tax liability-		
Depreciation, depletion and amortization	(19,458)	(18,318)
	-----	-----
Net deferred tax asset	\$ 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. Due to the full utilization of such carryforwards, the Company's effective tax rate in future years will approximate the statutory tax rate (both federal and state).

At December 31, 1995, the Company has net operating loss carryforwards for regular tax purposes of approximately \$44,891,000 and net operating loss carryforwards for alternative minimum tax purposes of approximately \$37,109,000 which expire in various amounts from 1999 to 2007. The Company has investment tax credit carryforwards of approximately \$3,530,000 which expire from 1996 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. Based on revised calculations, the estimated statutory depletion carryforward was reduced and the estimated deferred tax liability relating to DD&A was increased in the current year.

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. The Company issued 38,354 shares under the Plan in 1993. No shares were issued under the Plan in 1995 or 1994.

At December 31, 1995, 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 is based on market value on the date of the grant.

Activity pertaining to the Stock Option Plan is as follows:

	NUMBER OF SHARES	OPTION PRICE	
	-----	PER SHARE	AGGREGATE
		-----	-----
Outstanding at			
January 1, 1993	752,000	\$ 1.50 to 3.375	1,469,520
Granted	89,000	2.75	244,750
Exercised	(12,000)	1.50 to 2.37	(19,740)
	-----	-----	-----
Outstanding at			
December 31, 1993	829,000	1.50 to 3.375	1,694,530
Granted	102,500	3.00	307,500
Exercised	(16,000)	1.50 to 2.37	(24,870)
	-----	-----	-----

Outstanding at			
December 31, 1994	915,500	1.50 to 3.375	1,977,160
Granted	26,000	2.75 to 4.00	83,750
Exercised	(65,900)	1.50 to 2.75	(108,900)
Canceled	(10,000)	1.875	(18,750)
	-----	-----	-----
Outstanding at			
December 31, 1995	865,600	\$ 1.50 to 4.00	\$1,933,260
	=====	=====	=====

Options for 675,000, 676,400 and 610,500 shares were exercisable at prices ranging from \$1.50 to \$3.375 at December 31, 1995, 1994 and 1993, respectively.

43

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	OPTION PRICE	
	-----	PER SHARE	AGGREGATE
		-----	-----
Outstanding at			
January 1, 1993	10,000	\$ 1.75	\$ 17,500
Granted 10,000		3.75	37,500
	-----	-----	-----
Outstanding at			
December 31, 1993	20,000	1.75 to 3.75	55,000
Granted	10,000	2.875	28,750
	-----	-----	-----
Outstanding at			
December 31, 1994	30,000	1.75 to 3.75	83,750
Granted	12,500	3.375	42,188
	-----	-----	-----
Outstanding at			
December 31, 1995	42,500 (1)	\$1.75 to 3.75	\$ 125,938
	=====	=====	=====

(1) All 42,500 options were exercisable at December 31, 1995.

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 46,659, 32,685 and 28,352 shares of common stock and recognized expense of \$174,000, \$130,000 and \$162,000 in 1995, 1994 and 1993, respectively.

Effective March 1, 1993, the Company adopted a salary deferral plan ("Deferral Plan"). The Deferral Plan 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

44

defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy the Company's obligation under the Deferral Plan at December 31, 1995, 1994 and 1993 totaled \$271,000, \$108,000 and \$41,000, respectively. The Company recognizes payroll expense and records a liability at the time of deferral.

NOTE 8 - TRANSACTIONS WITH RELATED PARTIES

The Company formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 1995, 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. Pursuant to the terms of an agreement and plan of merger, seven limited partnerships, in which the Company was general partner, were consolidated into one new employee limited partnership effective December 31, 1993.

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:

	1995	1994	1993
	-----	-----	-----
	(In thousands)		
Contract drilling	\$ 34	\$ 53	\$ 60
Well supervision and other fees	\$ 119	\$ 226	\$ 278
General and administrative expense reimbursement	\$ 235	\$ 209	\$ 231

A subsidiary of the Company paid the Partnerships, for which the Company or a subsidiary is the general partner, \$18,000, \$38,000 and \$65,000 during the years ended December 31, 1995, 1994 and 1993, respectively, for purchases of natural gas production.

During 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 not exceed \$1.5 million.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

The Company leases office space under the terms of operating leases expiring through January 31, 2000. Future minimum rental payments under the terms of the leases are approximately \$264,000, \$244,000, \$246,000, \$246,000 and \$21,000 in 1996, 1997, 1998, 1999 and 2000, respectively. Total rent expense incurred by the Company was \$307,000, \$210,000 and \$208,000 in 1995, 1994 and 1993, respectively.

The Company had letters of credit supported by its Loan Agreement totaling \$935,000 at December 31, 1995.

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 \$34,000, \$38,000 and \$56,000 in 1995, 1994 and 1993, 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 10 - 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
	-----	-----	-----	-----	-----
(In thousands)					
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
	=====		=====	=====	=====
Year ended December 31, 1993:					
Drilling	\$ 14,676	\$ (306)	\$ 15,738	\$ 936	\$ 1,713
Oil and natural gas	24,073	8,957	64,845	11,422	7,018
	-----	-----	-----	-----	-----
	\$ 38,749	\$ 8,651	80,583	12,358	8,731
		=====			
Other	(67)		7,743	1,372	512
Discontinued operations	-		490	-	-
	-----		-----	-----	-----
Total	\$ 38,682		\$ 88,816	\$ 13,730	\$ 9,243
	=====		=====	=====	=====

(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, provision for litigation 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 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 1995 and 1994 is as follows:

	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	\$ 102	\$ 916	\$ 1,876
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:				
Continuing operations	\$.05	\$ -	\$.04	\$.09
Discontinued operations	-	-	-	(.01)
Gain on sale of discontinued operations	-	-	-	.02
Net income	\$.05 (2)	\$ -	\$.04 (3)	\$.10 (4)

48

	Three Months Ended			
	March 31	June 30	September 30	December 31
(In thousands except per share amounts)				
Year ended December 31, 1994:				
Revenues	\$ 10,587	\$ 11,064	\$ 11,939	\$ 10,305
Gross profit(1)	\$ 2,361	\$ 2,754	\$ 1,895	\$ 1,924
Income from continuing operations	\$ 1,135	\$ 1,407	\$ 1,542	\$ 544
Income from discontinued operations	76	18	48	24
Net income	\$ 1,211	\$ 1,425	\$ 1,590 (5)	\$ 568
Earnings Per Common Share:				
Continuing operations	\$.06	\$.07	\$.07	\$.03
Discontinued operations	-	-	-	-
Net income	\$.06	\$.07	\$.07 (5)	\$.03

(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.
- (5) Includes \$742,000 net gain on sale of natural gas gathering system.

NOTE 12 - 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)		
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
	=====	=====	=====
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
	=====	=====	=====

	-----	-----	-----
	(In thousands)		
1993:			
Capitalized costs:			
Proved properties	\$ 129,612	\$ 454	\$ 130,066
Unproved properties	2,638	-	2,638
	-----	-----	-----
	132,250	454	132,704
Less accumulated depreciation, depletion, amortization and impairment	73,419	314	73,733
	-----	-----	-----
Net capitalized costs	\$ 58,831	\$ 140	\$ 58,971
	=====	=====	=====
Cost incurred:			
Unproved properties	\$ 732	\$ -	\$ 732
Producing properties	1,241	-	1,241
Exploration	1,359	-	1,359
Development	8,084	6	8,090
	-----	-----	-----
Total costs incurred	\$ 11,416	\$ 6	\$ 11,422
	=====	=====	=====

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

	USA	Canada	Total
	-----	-----	-----
	(In thousands)		
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
	=====	=====	=====
1993:			
Revenues	\$ 22,040	\$ 67	\$ 22,107
Production costs	6,439	15	6,454
Depreciation, depletion and amortization	6,875	81	6,956
	-----	-----	-----
Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	\$ 8,726	\$ (29)	\$ 8,697
	=====	=====	=====

52

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	Natural	Oil	Natural	Oil	Natural
	Bbls	Gas	Bbls	Gas	Bbls	Gas
	-----	-----	-----	-----	-----	-----
		Mcf		Mcf		Mcf
	-----	-----	-----	-----	-----	-----
	(In thousands)					
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
	-----	-----	-----	-----	-----	-----
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

USA		Canada		Total	
Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf

(In thousands)

1993:

Proved developed and undeveloped reserves:

Beginning of year	3,308	63,761	-	931	3,308	64,692
Revision of previous estimates	(132)	4,662	-	-	(132)	4,662
Extensions, discoveries and other additions	549	9,169	-	-	549	9,169
Purchases of minerals in place	18	1,369	-	-	18	1,369
Sales of minerals in place	(42)	(147)	-	-	(42)	(147)
Production	(397)	(7,435)	-	(70)	(397)	(7,505)
End of Year	3,304	71,379	-	861	3,304	72,240

Proved developed reserves:

Beginning of year	3,245	58,809	-	468	3,245	59,277
End of year	3,187	65,395	-	426	3,187	65,821

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 explained above. 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)		
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
	=====	=====	=====
1993:			
Future cash flows	\$214,800	\$ 861	\$215,661
Future production and development costs	90,177	229	90,406
Future income tax expenses	17,097	244	17,341
	-----	-----	-----
Future net cash flows	107,526	388	107,914
10% annual discount for estimated timing of cash flows	34,374	157	34,531
	-----	-----	-----

Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	\$ 73,152	\$ 231	\$ 73,383
	<u>=====</u>	<u>=====</u>	<u>=====</u>

56

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

	USA	Canada	Total
	-----	-----	-----
	(In thousands)		
1995:			
Sales and transfers of oil and natural gas produced, 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	<u>\$102,823</u>	<u>\$ 315</u>	<u>\$103,138</u>
	<u>=====</u>	<u>=====</u>	<u>=====</u>
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	<u>\$ 78,018</u>	<u>\$ 250</u>	<u>\$ 78,268</u>
	<u>=====</u>	<u>=====</u>	<u>=====</u>

57

	USA	Canada	Total
	-----	-----	-----
1993:			
Sales and transfers of oil and natural gas produced, net of production costs	\$ (15,359)	\$ (52)	\$ (15,411)
Net changes in prices and production costs	(4,997)	73	(4,924)
Revisions in quantity estimates and changes in production timing	483	(70)	413
Extensions, discoveries and improved recovery, less related costs	12,886	-	12,886
Purchases of minerals in place	1,440	-	1,440
Sales of minerals in place	(284)	-	(284)
Accretion of discount	7,619	36	7,655
Net change in income taxes	(74)	(8)	(82)
Other - net	1,178	(4)	1,174
	-----	-----	-----

Net change	2,892	(25)	2,867
Beginning of year	70,260	256	70,516
	-----	-----	-----
End of year	\$ 73,152	\$ 231	\$ 73,383
	=====	=====	=====

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.

58

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.

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, 1995 and 1994 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, 1995. 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, 1995 and 1994, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 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 20, 1996

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 and Director	68	Chairman of the Board, Chief Executive Officer
John G. Nikkel	61	President, Chief Operating Officer and Director
Earle Lamborn	61	Senior Vice President, Drilling and Director
Philip M. Keeley Production	54	Senior Vice President, Exploration and
Larry D. Pinkston Officer	41	Vice President, Treasurer and Chief Financial
Mark E. Schell	38	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.

61

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.

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 1996 annual meeting of stockholders.

Item 11. Executive Compensation

Information required by this item is incorporated by reference from the

62

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 1996 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 1996 annual meeting of stockholders.
PART IV

63

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, 1995 and 1994
Consolidated Statements of Operations for the years ended

December 31, 1995, 1994 and 1993
Consolidated Statements of Changes in Shareholders' Equity for the
years ended December 31, 1995, 1994 and 1993
Consolidated Statements of Cash Flows for the years ended
December 31, 1995, 1994 and 1993
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, 1995, 1994 and 1993:
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).
- 64
- 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).

65

- 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).
- 10.2.2 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).

66

- 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).

67

- 10.2.22* The Company's Stock Option Plan (filed on the Company's Registration Statement of Form S-8 as S.E.C. File No. 33-44103, which is incorporated herein by reference)
- 10.2.23* Unit Corporation Non-Employee Directors' Stock Option Plan (filed on 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 on 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 herewith).

- 10.5 Acquisition and Development Agreement, dated September 26, 1991, between Registrant and Municipal Energy Agency of Nebraska (filed on 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 on 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 in Form 8-K dated December 15, 1994, which is incorporated herein by reference).
- 22.1 Subsidiaries of the Registrant (filed herewith).

68

- 24.1 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 under Form 8-K were filed during the quarter ended December 31, 1995.

69

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, 1995	\$ 289	\$ 55	\$ 228	\$ 116
	=====	=====	=====	=====
Year ended December 31, 1994	\$ 411	\$ -	\$ 122	\$ 289
	=====	=====	=====	=====
Year ended December 31, 1993	\$ 376	\$ -	\$ (35)	\$ 411
	=====	=====	=====	=====

Deferred Tax Asset Valuation Allowance:

Description	Balance at beginning of period	Additions	Deductions	Balance at end of period
-----	-----	-----	-----	-----
(In thousands)				
Year ended December 31, 1995	\$ 6,423	\$ -	\$ 2,893	\$ 3,530
	=====	=====	=====	=====
Year ended December 31, 1994	\$ 8,218	\$ -	\$ 1,795	\$ 6,423
	=====	=====	=====	=====
Year ended December 31, 1993	\$ 12,245	\$ -	\$ 4,027	\$ 8,218
	=====	=====	=====	=====

70

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 19, 1996 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 19th day of March, 1996.

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 LAMBORN	Senior Vice President, Drilling, Director
/s/ Larry D. Pinkston	

- -----	LARRY D. PINKSTON	Vice President, Chief Financial Officer and Treasurer
- -----	/s/ Stanley W. Belitz	Controller
- -----	STANLEY W. BELITZ	
- -----	/s/ Don Bodard	Director
- -----	DON BODARD	
- -----	/s/ Don Cook	Director
- -----	DON COOK	
- -----	/s/ William B. Morgan	Director
- -----	WILLIAM B. MORGAN	
- -----	/s/ John S. Zink	Director
- -----	JOHN S. ZINK	
- -----	/s/ John H. Williams	Director
- -----	JOHN H. WILLIAMS	

71

EXHIBIT INDEX

Exhibit No.	Description	Page
10.2.29	Unit 1996 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.	----
22.1	Subsidiaries of the Registrant.	
24.1	Consent of Independent Accountants.	
27	Financial Data Schedule.	

