F O R M 1 0 - K

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)

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

For the fiscal year ended December 31, 1994

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to

such filing requirements for the past 90 days. Yes X No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in PART III of this Form 10-K or any amendment to this Form 10-K. X

Aggregate Market Value of the Voting Stock Held By
Non-affiliates on March 15, 1995 - $44,446,596

Number of Shares of Common Stock
Outstanding on March 15, 1995 - 20,933,190

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 3, 1995 are incorporated by reference in Part III.

Exhibit Index - See Page 66

FORM 10-K

UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 1994

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, the development, acquisition and production of oil and natural gas properties and the marketing of natural gas. 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 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. 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 a major portion of the Company's operations as conducted through its wholly owned subsidiaries, Unit Petroleum Company and Roundup Resources, Inc.

As of December 31, 1994, the Company had 4,308 Mbbls and 93,360 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, 1994,

the Company had an interest in a total of 1,764 wells in the United States of which it served as the operator of 418. The Company also had an interest in 61 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:	1994 Gross	1994 Net	1993 Gross	1993 Net	1992 Gross	1992 Net
	Year Ended December 31,					
Exploratory:						
Oil..............	-	-	-	-	-	-
Natural gas......	1	.98	1	1.00	-	-
Dry..............	2	.80	1	0.10	-	-
Total	3	1.78	2	1.10	-	-
Development:						
Oil..............	5	5.00	12	11.98	2	2.00
Natural gas......	40	13.46	25	11.12	15	5.38
Dry..............	12	7.26	8	4.29	6	1.48
Total	57	25.72	45	27.39	23	8.86

Oil and natural gas wells producing or capable of producing:

	1994 Gross	1994 Net	1993 Gross	1993 Net	1992 Gross	1992 Net
Oil - USA........	675	177.68	337	162.09	329	130.70
Oil - Canada.....	-	-	-	-	-	-
Gas - USA........	1,089	179.99	709	141.76	715	132.03
Gas - Canada.....	61	1.53	61	1.53	56	1.40
Total	1,825	359.20	1,107	305.38	1,100	264.13

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

	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net
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
1992				
USA	228,363	86,144	36,169	18,736
Canada	31,360	784	-	-
Total	259,723	86,928	36,169	18,736

Price and Production Data. The average sales price, oil and natural gas production volumes and average production cost per equivalent barrel (6 thousand cubic feet (Mcf) of natural gas = 1 barrel (Bbl) of oil) of production, experienced by the Company, for the periods indicated were as follows:

	Year Ended December 31, 1994	1993	1992
Average sales price per barrel of oil produced:			
USA	$ 15.13	$ 16.73	$ 19.52
Canada	$ -	$ -	$ -
Average sales price per Mcf of natural gas produced:			
USA	$ 1.86	$ 2.07	$ 2.15
Canada	$ 1.27	$ 0.96	$ 0.93
Oil production (Mbbls):			
USA	406	397	375
Canada	-	-	-
Total	406	397	375
Natural gas production (MMcf):			
USA	9,606	7,435	6,730
Canada	53	70	80
Total	9,659	7,505	6,810
Average production expense per equivalent barrel:			
USA	$ 3.49	$ 3.93	$ 4.11
Canada	$ 2.19	$ 1.28	$ 0.76

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, 1994	1993	1992
Oil (Mbbls):			
USA	4,308	3,304	3,308
Canada	-	-	-
Total	4,308	3,304	3,308
Natural gas (Mmcf):			
USA	92,566	71,379	63,761
Canada	794	861	931
Total	93,360	72,240	64,692

Further information relating to oil and natural gas operations is presented in Notes 1, 2, 4, 9, 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.

The Company owns and operates 25 drilling rigs with drilling capabilities primarily in the 6,000 to 20,000 foot depth range. Historically, all of these drilling rigs were located in the Anadarko and Arkoma Basins of Oklahoma, Kansas, Arkansas and Texas. In 1994, the Company moved two 20,000 feet depth range rigs to the South Texas basin region thereby expanding the Company's market area for its contract drilling services. A third rig was moved under contract to the South Texas basin early in 1995. 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 drill pipe or other equipment. However, as certain grades of drill pipe start to reach the end of their useful life there is no assurance that sufficient supplies of such equipment will be readily available. In addition, given the general decline experienced in the land contract drilling industry over the past number of years, the Company's ability to utilize its full complement of drilling rigs, should economic conditions improve rapidly in the future, will be restricted due to a lack of equipment and qualified labor not only within the Company but in the industry as a whole.

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

	Year Ended December 31,				
	1994	1993	1992	1991	1990
Number of rigs owned at end of period	25	25	26	26	27
Average number of rigs utilized(1)	9.5	8.0	5.5	9.1	12.6
Number of wells drilled	95	84	56	92	106
Total footage drilled (feet in 1000's)	1027	788	527	736	991

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(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 15, 1995, 6 of the Company's 25 drilling rigs were operating under contract.

The following table sets forth, as of March 15, 1995, the type and approximate depth capability 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
U-15 Unit Rig	11,000
Gardner Denver 800	15,000
Brewster N-55	12,000
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
National 75	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

For the past several years, the Company's contract drilling services have encountered significant competition due to depressed levels of

activity in contract drilling as oil and natural gas prices remained below economic levels needed to encourage domestic exploration. While drilling operations of the Company showed continued improvement in 1994, this competition will, for the foreseeable future, continue to adversely affect the Company's drilling operations.

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. During the year ended December 31, 1994 turnkey revenue represented approximately 19% of the Company's contract drilling revenues. To date, the Company has not experienced significant losses in performing turnkey contracts.

Customers. During the last 3 years, approximately 8 customers have regularly used the Company for drilling operations. During the fiscal year ended December 31, 1994, 10 contract drilling customers accounted for approximately 10% of the Company's revenues. In addition, approximately 2% of the Company's revenues for the year ended December 31, 1994, were generated by drilling on oil and natural gas properties of which the Company was the operator (including properties owned by limited partner-

ships for which the Company acted as general partner). Such drilling was pursuant to contracts containing terms and conditions comparable to those contained in the Company's customary drilling contracts with non-affiliated operators.

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

NATURAL GAS MARKETING, GATHERING AND PROCESSING

The Company, through its wholly owned subsidiary, Mountain Front Pipeline Company ("Mountain Front"), is engaged in marketing natural gas from wells located primarily in Oklahoma and Texas and to a lesser extent in Arkansas, Kansas, Louisiana, Mississippi and New Mexico. Natural gas purchased from 5 customers during 1994 accounted for 32% of the Company's marketing activity. The Company owns 8 natural gas gathering systems. The Company also owns an interest in 2 natural gas processing plants located in Oklahoma and Mississippi and 44 natural gas compressors.

Revenues and expenses from the Company's natural gas marketing, gathering and processing activities for the periods indicated were as follows:

	Year Ended December 31,		
	1994	1993	1992
	(In thousands)		
Natural gas marketing and gathering revenue	$43,725	$31,624	$21,341
Natural gas processing revenue	$ 82	$ 181	$ 514
Other revenue	$ 364	$ 299	$ 115
Natural gas marketing and processing expense	$43,897	$32,325	$22,627

Mountain Front, while achieving substantial growth in revenues in recent years, has not, in the opinion of management, achieved the size necessary to reach desired levels of profitability. Consequently, the Company is currently negotiating to effect a business combination between Mountain Front's marketing operations and a third party. The combination, if completed, would leave the Company with a minority interest in the resulting larger entity. Such a combination would not adversely affect the operations of the Company's drilling and oil and natural gas exploration segments or the profitability of the Company as a whole, although it would result in a significant reduction in the Company's total revenues and associated costs.

Further information related to natural gas marketing, gathering and processing is presented in Note 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

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 short-term 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 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 slightly increased 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 and other factors relating to the Middle East. In view of the many uncertainties affecting the supply and demand for oil and natural gas the Company is unable to predict future oil and natural gas prices or the overall effect, if any, that a decline in demand or oversupply of such products would have on the Company.

COMPETITION

All lines of business in which the Company engages are highly competitive. Competition in land contract drilling traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of the Company's competitors in the land contract drilling business are substantially larger than the Company and have appreciably greater financial and other resources. As a result of the decrease in demand for land contract drilling services, a surplus of drilling rigs currently exists. 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 and the Company's natural gas marketing operations, likewise encounter strong competition from major oil companies, independent operators, marketers, pipelines 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 and the marketing of natural gas than the Company.

OIL AND NATURAL GAS PROGRAMS

The Company currently serves as a general partner to 5 oil and gas limited partnerships and 6 employee oil and gas limited partnerships. The employee partnerships acquire an interest 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. Prior to December 31, 1993, the Company was the general partner of seven additional employee limited partnerships. However, pursuant to the terms of an agreement and plan of merger these seven limited partnerships were consolidated into one new employee limited partnership effective December 31, 1993.

Under the terms of the partnership agreements of each limited partnership, the general partner, which in each case is Unit Petroleum Company, has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions on such matters as the partnership's participation in a drilling location or a property acquisition, the partnership's expenditure of funds and the distribution of funds to partners. Because the business activities of the limited partners on the one hand, and the general partner on the other hand, are not the same, conflicts of interest will exist and it is not possible to eliminate entirely such conflicts. Additionally, conflicts of interest may arise where the Company is the operator of an oil and natural gas well and also provides contract drilling services. Although the Company has no formal procedures for resolving such conflicts, the Company believes it fulfills its responsibility to each contracting party and complies fully with the terms of the agreements which regulate such conflicts.

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

EMPLOYEES

As of February 28, 1995, the Company had approximately 205 employees in its land contract drilling operations, 46 employees in its oil and natural gas operations, 9 employees in natural gas marketing and processing 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, oil and natural gas operations and natural gas processing facilities are subject to a variety of oil field hazards such as fire, explosion, blowouts, cratering and oil spills or certain other types of possible surface and subsurface pollution, any of which can cause personal injury and loss of life and severely damage or destroy equipment, suspend drilling operations and cause substantial damage to surrounding areas or property of others. As protection against some, but not all, of these operating hazards, the Company maintains broad insurance coverage, including all-risk physical damage, employer's liability and comprehensive general liability. In all states in which the Company operates except Oklahoma, the Company maintains worker's compensation insurance for losses exceeding $50,000. In Oklahoma, starting in August 1991, the Company elected to become self insured. In consideration therewith, the Company purchased an excess liability reinsurance policy. The Company believes that to the extent reasonably practicable such insurance coverages are adequate. The Company's insurance policies do not, however, provide protection against revenue losses incurred by reason of business interruptions caused by the destruction or damage of major items of equipment nor certain types of hazards such as specific types of environmental pollution claims. In view of the difficulties which may be encountered in renewing such insurance at reasonable rates, no assurance can be given that the Company will be able to maintain the amount of insurance coverage which it considers adequate at reasonable rates. Moreover, loss of or serious damage to any of the Company's equipment, although adequately covered by insurance, could have an adverse effect upon the Company's earning capacity.

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

GOVERNMENTAL REGULATIONS

The production and sale of oil and natural gas is highly affected by various state and federal regulations. All states in which the Company conducts activities impose restrictions on the drilling, production and sale of oil and natural gas, which often include requirements relating to well spacing, waste prevention, production limitations, pollution prevention and clean-up, obtaining drilling permits and similar matters. The following discussion summarizes, in part, the regulations of the United

States oil and natural gas industry and is not intended to constitute a complete discussion of the many statutes, rules, regulations and governmental orders to which the Company's operations may be subject.

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

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

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

One of the initiatives FERC adopted was order 636. In brief, the primary requirements of Order 636 are as follows: pipelines must separate their sales and transportation services; pipelines must provide open access transportation services that are equal in quality for all natural gas suppliers and must provide access to storage on an open access contract basis; pipelines that provide firm sales service on May 18, 1992 must offer a "no-notice" firm transportation service under which firm shippers may receive delivery of natural gas on demand up to their firm entitlement without incurring daily balancing and scheduling penalties; pipelines must provide all shippers with equal and timely access to information relevant to the availability of their open access transportation services; open access pipelines must allow firm transportation customers to downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines; pipelines must implement a capacity releasing program so that

firm shippers can release unwanted capacity to those desiring capacity (which program replaces previous "capacity brokering" and "buy-sell" programs); existing bundled firm sales entitlement are converted to unbundled firm sales entitlement and to unbundled firm transportation rights on the effective date of a particular pipeline's blanket sales certificate; and pipeline transportation rights must be developed under the Straight Fixed Variable (SFV) method of cost classification, allocation and rate design unless the FERC permits the pipeline to use some other method. The FERC will not permit a pipeline to change the new resulting rates until the FERC accepts the pipeline's formal restructuring plans.

In essence, the goal of Order 636 is to make a pipeline's position as natural gas merchant indistinguishable from that of a non-pipeline supplier. It, therefore, pushes the point or sale of natural gas by pipelines upstream, perhaps all the way to the wellhead. Order 636 also requires pipelines to give firm transportation customers flexibility with respect to receipt and delivery points (except that a firm shipper's choice of delivery point cannot be downstream of the existing primary delivery point) and to allow "no-notice" service (which means that natural gas is available not only simultaneously but also without prior nomination, with the only limitation being the customer's daily contract demand) if the pipeline offered no-notice city-gate sales service on May 18, 1992. Thus, this separation of pipelines' sales and transportation allows non-pipeline sellers to acquire firm downstream transportation rights and thus to offer buyers what is effectively a bundled city-gate sales service and it permits each customer to assemble a package of services that serves its individual requirements. But it also makes more difficult the coordination of natural gas supply and transportation. A corollary to these changes is that all pipelines will be permitted to sell natural gas at market-based rates.

The results of these changes may be the increased availability of firm transportation and the reduction of interruptible transportation, with a corresponding reduction in the rates for off-peak and interruptible transportation. 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.

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.

Item 3. Legal Proceeding

The Company is a party to a settlement agreement dated January 31, 1991 with a natural gas purchaser which superseded a settlement agreement entered into during March of 1988. Under the agreements the purchaser made certain prepayments to the Company for natural gas to be delivered to the purchaser in the future. As of December 31, 1994, this prepayment balance for natural gas yet to be delivered was $3.7 million. The Company has learned that the Oklahoma Tax Commission (the "Commission"), based on four assessments, one in 1988, one in 1992 and two in 1994, is seeking to hold the purchaser liable for certain taxes, interests and penalties that the Commission contends are due and owing with respect to the prepayment amounts made by the purchaser under the agreements on the grounds that the prepayments are solely attributable to the settlement of past claims for take-or-pay obligations. To date, the Company is not a party to the Commission's proceedings, but may in the future, seek to intervene in these proceedings. The purchaser has denied the claims made by the Commission and is contesting the assessments. The purchaser and the Commission have settled the 1988 assessment for approximately $51,000 and the remaining three assessments have been consolidated and set for a hearing before an administrative law judge on or before May 10, 1995. The purchaser has notified the Company of the proceedings and has indicated its intention to assert claims against the Company to recover the amount it paid in settlement of the 1988 assessment (including its attorney fees) as well as any amounts it might have to pay by virtue of the remaining assessments. The Company is aware that the purchaser has made such claims against other companies which also received prepayments from the purchaser, although the type of agreements and the facts involved in those cases are not known by the Company. At this time, the Company is unable to determine what the outcome of the remaining Commission's proceedings will be, the amount of taxes, if any, plus interest and penalties that may ultimately be assessed against the purchaser and the claims, if any, that the purchaser might seek to assert against the Company in the event an unfavorable result is incurred by the purchaser. The Company has advised the purchaser that it believes the responsibility for the payment of the taxes, interest and

penalty sought by the Commission, should it be ultimately determined that any such amounts are in fact owed, is the responsibility of the purchaser and not the Company.

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, 1994.

PART II

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

As of February 21, 1995, the Company had 3,512 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:

	1994		1993	
QUARTER	High	Low	High	Low
First	$3 1/2	$2 5/8	$3 1/4	$1 5/8
Second	$3 1/4	$2 3/4	$4 3/8	$2 3/4
Third	$3 1/2	$2 5/8	$4 3/4	$3 1/4
Fourth	$3 7/8	$2 5/8	$4 3/4	$2 5/8

Item 6. Selected Financial Data

	Year Ended December 31,				
	1994	1993	1992	1991	1990
	(In thousands except per share amounts)				
Revenues	$87,958	$70,941	$55,827	$69,652	$61,904
Income Before Income Taxes	$ 4,814	$ 3,892	$ 1,102(1)	$ 4,436	$ 830
Net Income	$ 4,794	$ 3,871	$ 1,087(1)	$ 4,341	$ 830
Net Income Per Common Share	$.23	$.19	$.05(1)	$.21	$.04
Total Assets	$112,421	$95,762	$88,710	$92,086	$86,286
Long-Term Debt	$ 37,824	$25,919	$22,298	$23,153	$19,929
Long-Term Portion of Natural Gas Purchaser Prepayments	$ 2,149	$ 4,417	$ 5,924	$ 7,626	$ 9,481
Cash Dividends Per Common Share	$ -	$ -	$ -	$ -	$ -

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(1) Includes a $1.5 million provision for litigation

See Management's Discussion of Financial Condition and Results of Operations for a review of 1994, 1993 and 1992 activity.

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

Financial Condition and Liquidity

On December 12, 1994, the Company amended its credit agreement (as amended the "Agreement"), in part to provide funds for the December 15, 1994 closing of a producing oil and natural gas property acquisition from two subsidiaries of Patrick Petroleum Company (collectively "Patrick"). The acquisition consisted of producing properties, located in Alabama, Louisiana, Mississippi, New Mexico, Oklahoma and Texas and related accounts receivable and certain related assumed liabilities for a net cost of $13.2 million. The Agreement provides for a total commitment of $50 million, consisting of a revolving credit facility through January 1, 1997 and a term loan thereafter, maturing on January 1, 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 $42 million of the commitment is available to the Company. Certain covenants of the Agreement were also amended. The Company must maintain consolidated net worth of at least $45 million, a modified current ratio of not less than 1 to 1, a ratio of long-term debt, as defined in the Agreement, to consolidated tangible net worth not greater than 1 to 1 and a ratio of total liabilities, as defined in the Agreement, to consolidated tangible net worth not greater than 1.25 to 1. In addition, working capital provided by operations, as defined in the Agreement, cannot be less than $13 million in any year. At December 31, 1994, borrowings under the Agreement totalled $37.3 million. At February 21, 1995, borrowings under the Agreement totalled $37.0 million with $2.7 million available for future borrowings. The interest rate on the bank debt was 8.5 and 9 percent at December 31, 1994 and February 21, 1995, respectively. A commitment fee of 1/2 of 1 percent is charged for any unused portion of the borrowing base.

Shareholders' equity at December 31, 1994 was $52.6 million, making the Company's ratio of long-term debt-to-equity .72 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 Agreement. Net cash provided by operating activities in 1994 was $13.2 million as compared to $9.9 million in 1993.

The Company's capital expenditures during 1994 were $27 million. The majority of the capital expenditures, $25.1 million, were made in the Company's oil and natural gas operations with $11.5 million and $13.1 million used for exploration and development drilling and producing property acquisitions, respectively. Capital expenditures made by the Company's contract drilling operations were approximately $1.1 million in 1994 and principally consisted of 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 may be required in 1995 for drill pipe as certain grades of the Company's drill pipe are reaching the end of their useful life.

Late in December 1994, Unit agreed to acquire producing oil and natural gas properties for a purchase price of $2,125,000. This acquisition has an effective date of January 1, 1995 and includes ten natural gas wells located in Lipscomb County, Texas.

During the first half of 1995, the Company plans to pay down a portion of its long-term debt while continuing its developmental drilling on a limited basis. 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 current 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 $16 million on its capital expenditure program in 1995.

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, 1994 prepayment balance of $3.7 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 $211,000 or a minimum of

$110,000 per month for the year 1995. 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 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 1995. 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 installments over a five year period. 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 1993, the Company, in accordance with the terms of the Settlement Agreement, elected to deliver natural gas at approximately 80 percent of the deliverability of the wells subject to the Settlement Agreement. During 1994 natural gas delivered was again reduced to approximately 75 percent of the deliverability of the wells subject to the Settlement Agreement. However, 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 by approximately $1.8, $1.9 and $2.8 million in 1994, 1993 and 1992, respectively.

Oil prices received by the Company in 1994 ranged from an average of $12.53 in February to $17.78 in July and averaged $15.73 in December. The Company's average price for oil received in 1994 was $15.13. Average natural gas prices received by the Company have gradually declined since the first quarter of 1994, and December's average price of $1.52 per Mcf was 32 percent less than the average natural gas price of $2.24 received by the Company in March 1994. Oil prices received early in the first quarter of 1995 were 3 percent higher than average prices received by the Company at December 31, 1994 while spot prices for natural gas dropped 17 percent from the December 31, 1994 price. Oil prices within the industry remain largely dependent upon world market developments for crude oil. Prices for natural gas are influenced by weather conditions and supply imbalances, particularly in the domestic market, and by world wide oil price levels. The large drop in spot market natural gas prices had a significant adverse effect on the value of the Company's reserves at year end 1994 and could cause the Company to reduce the carrying value of its oil and natural gas properties in 1995 (see Note 12 of Notes to Consolidated Financial Statements). Likewise, declines in natural gas or oil prices could adversely effect the semi-annual borrowing base determination under the Company's current credit agreement since this determination is, for the most part, calculated on the value of the Company's oil and natural gas reserves.

The Company's ability to utilize its full complement of drilling rigs, should economic conditions improve in the future, will be restricted due to the lack of qualified labor and certain supporting equipment not only within the Company but in the industry as a whole. The Company's ability to utilize its drilling rigs at any given time is dependent on a number of factors, including but not limited to, the price of both oil and natural gas, the availability of labor and the Company's ability to supply the type of equipment required. The Company's management expects that these factors will continue to influence the Company's rig utilization during 1995.

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. At December 31, 1994 25,100 shares had been repurchased at prices ranging from $2 5/8 to $3 3/8 per share.

The Company's wholly owned natural gas marketing subsidiary, Mountain Front Pipeline Company, while achieving substantial growth in revenues in recent years, has not achieved the size necessary to reach desired levels of profitability. Consequently, the Company is currently negotiating to effect a business combination between Mountain Front Pipeline Company's marketing operations and a third party. The combination, if completed, would leave the Company with a minority interest in the resulting larger

entity. Such a combination would not adversely affect the operations of the Company's drilling and oil and natural gas exploration segments or the profitability of the Company as a whole, although it would result in a significant reduction in the Company's total revenues and associated costs.

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

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 and natural gas marketing operations 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 were $87,958,000 in 1994 and $70,941,000 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 and partially offset the increases in production. Average natural gas prices received by the Company declined due to a 14 percent reduction in average spot market prices received by the Company coupled with a 14 percent reduction in volumes produced from certain wells included under a settlement agreement which contains provisions for prices which are higher than current spot market prices. Approximately 92 percent of the Company's natural gas production was sold under spot market prices in 1994 as compared with 88 percent in 1993.

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.

In July 1994, the Company moved one of its rigs under a multi-well contract to the South Texas Basin creating a new operating region for the Company to market its drilling services. In November, the Company moved a

second rig under contract into the region and a third rig was moved under contract in February 1995.

The Company's marketing and natural gas processing revenues increased 38 percent as the marketing operation moved 53 percent higher volumes in 1994 while experiencing a 15 percent decrease in prices.

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 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.

Natural gas marketing and processing operating margins improved from a negative 1 percent in 1993 to a positive 1 percent in 1994. Increased volumes marketed in 1994 helped to improve the Company's ability to cover its fixed overhead. Total natural gas marketing and processing expense increased 36 percent due to increased volumes marketed between the comparative periods.

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 dropped from $4.13 in 1993 to $4.08 in 1994.

General and administrative expense increased 8 percent as certain employee and reporting costs increased between the comparative years. This increase is expected to continue in 1995 as the Company continues to expand its area of operation. 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 previously discussed.

1993 versus 1992
- ----------------

Net income for 1993 was $3,871,000, compared with $1,087,000 in 1992. The increase in 1993 resulted primarily from improved operating results associated with the contract drilling segment. Additionally net income for

1992 was negatively impacted by a $1.5 million provision for certain litigation.

Total revenues were $70,941,000 in 1993 and $55,827,000 in 1992. Oil and natural gas revenues increased 3 percent due to a 10 percent increase in natural gas production and a 6 percent increase in oil production between 1993 and 1992. Average natural gas and oil prices received by the Company decreased 4 and 14 percent, respectively, and partially offset the increases in production. Although spot market natural gas prices increased, the Company's natural gas price was negatively impacted by a 26 percent reduction in volumes produced from certain wells included under a settlement agreement which contains provisions for prices which are higher than current spot market prices. Approximately 88 percent of the Company's natural gas production was sold under spot market prices in 1993 as compared with 83 percent in 1992.

Higher spot market natural gas prices had a positive effect on the Company's contract drilling operations. Revenues from contract drilling operations increased 51 percent as utilization went from 21 percent in 1992 to 31 percent in 1993. Rising spot market natural gas prices encouraged domestic operators to increase their focus on drilling new wells as opposed to acquiring producing properties as in previous years. To a lesser extent, the increase in drilling revenues resulted from higher rates per day for daywork drilling and a greater portion of the Company's contract drilling being performed under turnkey and footage contracts. 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. Daywork revenues represented 47 percent of total drilling revenues in 1993 as opposed to 51 percent in 1992.

The Company's marketing and natural gas processing revenues increased 46 percent as the marketing operations began moving higher volumes in 1993 after experiencing reduced volumes in 1992 which were associated with the change in focus of its marketing activity toward an end user market. The Company had previously marketed its natural gas primarily to broker and commodity markets.

Increased revenues were complemented by improved operating margins (revenues less operating costs) in 1993 versus 1992 from both contract drilling and natural gas marketing and processing. Operating margins for the Company's oil and natural gas operations declined from 68 percent to 66 percent due primarily to the decrease in average prices received for oil and natural gas. Total operating costs from oil and natural gas operations increased 7 percent as the Company increased production from reserves added primarily through developmental drilling in 1993 and from producing property acquisitions in 1992.

Operating margins for contract drilling showed significant improvement as they moved from a negative 2 percent in 1992 to a positive 10 percent in 1993. This increase was a result of a reduction in fixed overhead expense made by the Company during the last six months of 1992, reduced worker's compensation expense and increased rig utilization and dayrates which provided greater revenue to cover fixed costs. Total operating costs for

contract drilling were up 34 percent in 1993 versus 1992 due to the increased utilization.

Natural gas marketing and processing operating margins improved from a negative 3 percent in 1992 to a negative 1 percent in 1993. Increased volumes marketed in 1993 helped to improve the Company's ability to cover its fixed overhead. Total natural gas marketing and processing expense increased 43 percent due to the increased volumes marketed between the comparative periods.

Contract drilling depreciation increased 33 percent in response to increased rig utilization and a $160,000 write down in value of components previously utilized on one of the Company's rigs which was retired at December 31, 1993. Depreciation, depletion and amortization ("DD&A") of oil and natural gas properties decreased 2 percent as the Company's average DD&A rate per equivalent barrel dropped from $4.67 per equivalent barrel in 1992 to $4.13 per equivalent barrel in 1993. The effect of the decreased rate was partially offset by increased production volumes between the comparative periods.

General and administrative expense increased 6 percent, primarily due to increased payroll, employee benefits and office related expenses. Interest expense decreased 19 percent as interest rates remained stable and the Company's average debt outstanding for the year of 1993 remained below the average debt outstanding in 1992.

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	As of December 31, 1994	1993
	(In thousands)	
Current Assets:		
Cash and cash equivalents	$ 2,749	$ 3,756
Short-term investments	-	41
Accounts receivable (less allowance for doubtful accounts of $289 and $411)	16,369	14,099
Materials and supplies	1,498	1,424
Prepaid expenses and other	1,222	736
Total current assets	21,838	20,056
Property and Equipment:		
Drilling equipment	75,746	75,528
Oil and natural gas properties, on the full cost method	157,393	132,704
Transportation equipment	3,341	2,851
Other	7,925	8,541
	244,405	219,624
Less accumulated depreciation, depletion, amortization and impairment	153,862	144,099
Net property and equipment	90,543	75,525
Other Assets	40	181
Total Assets	$112,421	$ 95,762

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

LIABILITIES AND SHAREHOLDERS' EQUITY	As of December 31, 1994	1993
	(In thousands)	
Current Liabilities:		
Current portion of long-term debt	$ 496	$ 481
Current portion of natural gas purchaser prepayments (Note 4)	1,580	1,170
Accounts payable	14,593	14,008
Accrued liabilities	3,014	1,983
Contract advances	158	10
Total current liabilities	19,841	17,652
Natural Gas Purchaser Prepayments (Note 4)	2,149	4,417
Long-Term Debt	37,824	25,919
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, 20,910,190 and 20,861,505 shares issued, respectively	4,182	4,172
Capital in excess of par value	50,086	49,977
Accumulated deficit	(1,581)	(6,375)
Treasury stock, at cost (25,100 shares)	(80)	-
Total shareholders' equity	52,607	47,774
Total Liabilities and Shareholders' Equity	$ 112,421	$ 95,762

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 1994	1993	1992
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$16,952	$14,676	$ 9,732
Oil and natural gas	26,001	24,073	23,464
Natural gas marketing and processing	44,171	32,104	21,970
Other	834	88	661
Total revenues	87,958	70,941	55,827

Expenses:			
Contract drilling:			
Operating costs	14,909	13,269	9,901
Depreciation and impairment	2,030	1,713	1,284
Oil and natural gas:			
Operating costs	8,799	8,098	7,538
Depreciation, depletion and amortization	8,281	7,018	7,128
Natural gas marketing and processing	43,897	32,325	22,627
General and administrative	3,574	3,302	3,114
Interest	1,654	1,324	1,633
Provision for litigation	-	-	1,500
Total expenses	83,144	67,049	54,725
Income Before Income Taxes	4,814	3,892	1,102
Income Tax Expense	20	21	15
Net Income	$ 4,794	$ 3,871	$ 1,087
Net Income Per Common Share	$ .23	$ .19	$ .05
Weighted Average Shares Outstanding (Both Primary and Fully Diluted)	20,900	20,860	20,781

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 1992, 1993 and 1994

	Common Stock	Capital In Excess Of Par Value	Accumulated Deficit	Treasury Stock	Total
			(In thousands)		
Balances, January 1, 1992	$ 4,143	$49,733	$(11,333)	$ -	$42,543
Net income	-	-	1,087	-	1,087
Activity in employee compensation plans (67,755 shares)	14	108	-	-	122
Balances, December 31, 1992	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

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, 1994	1993	1992
	(In thousands)		
Cash Flows From Operating Activities:			
Net income	$ 4,794	$ 3,871	$ 1,087
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	10,774	9,256	8,772
Gain on disposition of assets	(813)	(49)	(463)
Employee stock compensation plans	119	151	122
Bad debt expense	-	-	200
Provision for litigation	-	-	1,500
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(939)	(1,257)	2,493
Materials and supplies	(74)	(99)	121
Prepaid expenses and other	(486)	83	191
Accounts payable	735	634	(747)
Accrued liabilities	760	(947)	(151)
Contract advances	148	8	(876)
Natural gas purchaser prepayments	(1,858)	(1,743)	(2,319)
Net cash provided by operating activities	13,160	9,908	9,930

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, 1994	1993	1992
		(In thousands)	
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions)	$(28,227)	$(11,946)	$(10,768)
Proceeds from disposition of assets	2,038	709	1,146
Decrease in short-term investments	41	664	170
(Acquisition) disposition of other assets	141	(45)	60
Net cash used in investing activities	(26,007)	(10,618)	(9,392)
Cash Flows From Financing Activities:			
Borrowings under line of credit	63,700	43,400	23,900
Payments under line of credit	(51,300)	(40,600)	(24,700)
Proceeds from notes payable and other long-term debt	-	911	710
Payments on notes payable and other long-term debt	(480)	(367)	(80)
Acquisition of treasury stock	(80)	-	-
Net cash provided by (used in) financing activities	11,840	3,344	(170)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,007)	2,634	368
Cash and Cash Equivalents, Beginning of Year	3,756	1,122	754
Cash and Cash Equivalents, End of Year	$ 2,749	$ 3,756	$ 1,122
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest	$ 1,548	$ 1,326	$ 1,673
Income taxes	$ 2	$ 2	$ 63

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.

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 original maturities at date of purchase of three months or less which are readily convertible into known amounts of cash.

Property and Equipment

Drilling equipment, transportation equipment and other property and equipment are carried at cost. The Company provides for depreciation of drilling equipment on the units-of-production method based on estimated useful lives, including a minimum provision of 20 percent of the active rate when the equipment is idle. At December 31, 1993, one of the Company's rigs was retired and certain components of the rig were written down by $160,000 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.

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 dispo-

sitions 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 $4.08, $4.13 and $4.67 per equivalent barrel in 1994, 1993 and 1992, 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.

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 1993 and 1992.

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. Prior to December 31, 1993, the Company also was general partner of seven additional employee limited partnerships. However, pursuant to the terms of an agreement and plan of merger, these seven limited partnerships were consolidated into one new employee limited partnership effective December 31, 1993.

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

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes". SFAS No. 109 requires the measurement of deferred tax assets for deductible temporary differences and operating loss carryforwards, and of deferred tax liabilities for taxable temporary differences. Measurement of current and deferred 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. Deferred tax assets primarily result from net operating loss carryforwards, and deferred tax liabilities result from the recognition of depreciation, depletion and amortization in different periods for financial reporting and tax purposes. 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 1994 average spot market natural gas price of $1.65 per Mcf, the Company estimates its balancing position to be approximately $5.5 million on under-produced properties and approximately $3.1 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

At December 31, 1994, the Company had natural gas price swaps, related to its marketing of natural gas, which qualify as hedges of the Company's future purchase and sales commitments. Gains or losses on these swaps are recognized in the consolidated statement of operations and included in operating cash flows in the same period as the associated sale of natural gas occurs. At December 31, 1994, the Company had price swap agreements for 380,000 Mcf totaling $525,000 related to purchase commitments and 358,000 Mcf totaling $694,000 related to sales commitments for the period of January through March of 1995.

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trade receivables with a variety of national and international oil and natural gas companies. The Company does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large

number of customers comprising the Company's customer base. The Company had one customer in its natural gas marketing operation at December 31, 1993, with an accounts receivable balance of $4.1 million which was subsequently paid in January 1994. In addition, at December 31, 1994 and 1993, the Company had a concentration of cash of $2.3 and $3.4 million, respectively, with one bank.

RECLASSIFICATIONS

Certain reclassifications have been made in the 1992 and 1993 consolidated financial statements to conform them to classifications used in 1994.

NOTE 2 - PRODUCING PROPERTY ACQUISITION

On December 15, 1994, Unit Petroleum Company, a wholly owned subsidiary of Unit Corporation, acquired interests in approximately 700 oil and natural gas wells located primarily in Oklahoma, Texas, New Mexico and Louisiana. Financing for the transaction was provided under the Company's bank credit agreement. The acquisition is summarized as follows:

Current assets net of current liabilities	$ 976,000
Producing oil and natural gas properties	12,261,000
Net assets acquired	$13,237,000

Unaudited summary pro forma results of operations for the Company, reflecting the above described acquisition as if it had occurred at the beginning of the years ended December 31, 1994 and December 31, 1993, are as follows, respectively; revenues, $94,373,000 and $79,807,000; net income, $5,068,000 and $7,259,000; and net income per common share, $.24 and $.35. The pro forma results of operations are not necessarily indicative of the actual results of operations that would have occurred had the purchase actually been made at the beginning of the respective periods nor of the results which may occur in the future.

NOTE 3 - 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 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, 1994 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, the Company has a prepayment balance of $3.7 million at December 31, 1994 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, 1994 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 $211,000 or a minimum of $110,000 per month for the year 1995. 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 payments over a five year period. 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. 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, 1994 and 1993:

	1994	1993
	(In thousands)	
Revolving credit and term loan, with interest at December 31, 1994 and 1993 of 8.5% and 6%, respectively	$ 37,300	$ 24,900
Other	1,020	1,500
	38,320	26,400
Less current portion	496	481
Total long-term debt	$ 37,824	$ 25,919

At December 31, 1994, the Company's credit agreement ("Agreement") provided for a total loan commitment of $50 million consisting of a revolving credit facility through January 1, 1997 and a term loan thereafter, maturing on January 1, 2001. Borrowings under the Agreement are limited to a semi-annual borrowing base computation which as of December 31, 1994 is $42 million.

The principal of the revolving credit facility is due in 48 equal monthly payments commencing February 1, 1997 and continuing on the first day of each month thereafter through maturity. The outstanding principal amount of the revolving credit facility which is less than or equal to the loan value of the mineral interest then in effect shall bear interest at the Chase Manhattan Bank, N.A. prime rate ("Prime Rate") and that portion of the outstanding balance exceeding such loan value shall bear interest at the Prime Rate plus 1 and 1/2 percent through January 1, 1997. Subsequent to January 1, 1997 and continuing through January 1, 2001, the portion of the outstanding amount under the Agreement which is less than or equal to the loan value of the mineral interests then in effect shall bear interest at the Prime Rate plus 1/4 of 1 percent and any portion of the outstanding principal balance exceeding such loan value shall bear interest equal to the Prime Rate plus 1 and 1/2 percent. The Agreement also provides for a commitment fee of 1/2 of 1 percent of the 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 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, (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 Agreement also requires that the Company maintain consolidated net worth of at least $45 million, a modified current ratio of not less than 1 to 1, a ratio of long-term debt, as defined in the Agreement, to consolidated tangible net worth not greater than 1 to 1 and a ratio of total liabilities, as defined in the Agreement, to consolidated tangible net worth not greater than 1.25 to 1. In addition, working capital provided by operations, as defined in the Agreement, cannot be less than $13 million in any year.

Estimated annual principal payments under the terms of all long-term debt from 1995 through 1999 are $496,000, $200,000, $200,000, $8,671,000 and $9,325,000.

NOTE 6 - INCOME TAXES

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

	1994	1993	1992
		(In thousands)	
Income tax expense computed by applying the statutory rate	$ 1,637	$ 1,323	$ 375
Tax benefit of net operating loss carryforward	(1,652)	(1,308)	(396)
Alternative minimum tax	-	-	2
State income tax	6	1	7
Other	29	5	27
Income tax expense	$ 20	$ 21	$ 15

Deferred tax assets and liabilities are comprised of the following at December 31, 1994 and 1993:

	1994	1993
Deferred tax assets:	(In thousands)	
Allowance for losses	$ 521	$ 580
Gas purchaser prepayments	-	149
Net operating loss carryforwards	18,190	18,118
Statutory depletion carryforward	2,500	2,500
Investment tax credit carryforward	3,530	3,530
Gross deferred tax assets	24,741	24,877
Deferred tax liabilities:		
Depreciation, depletion and amortization	18,318	16,659
Gross deferred tax liabilities	18,318	16,659
Net deferred tax asset	6,423	8,218
Valuation allowance	6,423	8,218
	$ -	$ -

The net deferred tax asset valuation allowance reflects that the tax 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.

At December 31, 1994, the Company has net operating loss carryforwards for regular tax purposes of approximately $47,868,000 and net operating loss carryforwards for alternative minimum tax purposes of approximately

$38,260,000 which expire in various amounts from 1999 to 2007. The Company has investment tax credit carryforwards of approximately $3,530,000 which expire from 1995 to 2000. In addition, a statutory depletion carryforward of approximately $6,579,000 is available to reduce future taxable income, subject to statutory limitations. Statutory depletion may be carried forward indefinitely.

In 1987, the Company completed an equity offering which constituted an ownership change as that term is used in the Internal Revenue Code. As a result of the ownership change, the amount of taxable income in future years which may be offset by the Company's net operating loss carryovers prior to the ownership change is limited. Tax losses of $45,950,000 at December 31, 1994 are not subject to these limitations. The remaining tax net operating loss carryforward will become available for utilization by the Company at a rate of $3,500,000 per year. Similar limitations apply to investment tax credits.

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. 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 and 50,788 shares under the Plan in 1993 and 1992, respectively. No shares were issued under the Plan in 1994.

The Company has a Stock Option Plan which provides for the granting of options for up to 1,000,000 shares of common stock to officers and employees. The plan permits the issuance of qualified or nonqualified stock options. Stock options granted in 1986 became exercisable at the rate of 20 percent per year through 1990. Options granted subsequent to 1986 become exercisable at the rate of 20 percent per year one year after being granted.

Activity pertaining to the Stock Option Plan is as follows:

	NUMBER OF SHARES	OPTION PRICE PER SHARE	OPTION PRICE AGGREGATE
Outstanding at January 1, 1992	752,000	$1.50 to 3.375	$1,476,995

Granted	10,000	1.875	18,750
Cancelled	(10,000)	2.37 to 2.875	(26,225)
Outstanding at December 31, 1992	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

Options for 676,400, 610,500 and 556,400 shares were exercisable at prices ranging from $1.50 to $3.375 at December 31, 1994, 1993 and 1992, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). An aggregate of 100,000 shares of the Company's common stock may be issued or delivered 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	OPTION PRICE AGGREGATE
1992:			
Granted	10,000	$ 1.75	$ 17,500
Outstanding at December 31, 1992	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)	$1.75 to 3.75	$ 83,750

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(1) All 30,000 options were exercisable at December 31, 1994.

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 32,685, 28,352 and 16,967 shares of common stock and recognized expense of $130,000, $162,000 and $33,000 in 1994, 1993 and 1992, 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 defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy the Company's obligation under the Deferral Plan at December 31, 1994 and 1993 totaled $108,000 and $41,000, respectively. The Company recognizes payroll expense and records a deferred 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 1994, 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:

	1994	1993	1992
		(In thousands)	
Contract drilling	$ 53	$ 60	$ 38
Well supervision and other fees	$ 226	$ 278	$ 277
General and administrative expense reimbursement	$ 209	$ 231	$ 294

A subsidiary of the Company paid the Partnerships, for which the Company or a subsidiary is the general partner, $38,000, $65,000 and $58,000 during the years ended December 31, 1994, 1993 and 1992, respectively, for purchases of natural gas production.

During 1993 and 1992, the Company received legal services from a law firm of which one of the Company's directors was a partner. Total payments to the law firm during 1993 and 1992 were $164,000 and $130,000, respectively. The Company did not receive such services from the law firm in 1994.

During 1994, a bank owned by one of the Company's Directors became a participant in the Company's loan agreement. The bank's total pro rata share of the Company's line of credit is not to exceed $1.5 million.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

The Company is currently negotiating a new operating lease agreement to remain in its current office space until February 1, 2000. Future minimum rental payments under the proposed terms of the lease would be approximately $205,000, $224,000, $244,000, $246,000 and $246,000 in 1995, 1996, 1997, 1998 and 1999, respectively. Total rent expense incurred by the Company was $210,000, $208,000 and $205,000 in 1994, 1993 and 1992, respectively.

The Company had letters of credit totaling $835,600 outstanding at December 31, 1994.

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 $38,000, $56,000 and $70,000 in 1994, 1993 and 1992, respectively, for such limited partner's interest.

The Company is a party to a settlement agreement dated January 31, 1991 with a natural gas purchaser which superseded a settlement agreement entered into during March of 1988. Under the agreements the purchaser made certain prepayments to the Company for natural gas to be delivered to the purchaser in the future. As of December 31, 1994, this prepayment balance for natural gas yet to be delivered was $3.7 million. The Company has learned that the Oklahoma Tax Commission (the "Commission"), based on four assessments, one in 1988, one in 1992 and two in 1994, is seeking to hold the purchaser liable for certain taxes, interests and penalties that the Commission contends are due and owing with respect to the prepayment amounts made by the purchaser under the agreements on the grounds that the prepayments are solely attributable to the settlement of past claims for take-or-pay obligations. To date, the Company is not a party to the Commission's proceedings, but may in the future, seek to intervene in these proceedings. The purchaser has denied the claims made by the Commission and is contesting the assessments. The purchaser and the Commission have settled the 1988 assessment for approximately $51,000 and the remaining three assessments have been consolidated and set for a hearing before an administrative law judge on or before May 10, 1995. The purchaser has notified the Company of the proceedings and has indicated its intention to assert claims against the Company to recover the amount it paid in settlement of the 1988 assessment (including its attorney fees) as well as any amounts it might have to pay by virtue of the remaining assessments. The Company is aware that the purchaser has made such claims against other companies which also received prepayments from the purchaser, although the type of agreements and the facts involved in those cases are not known by the Company. At this time, the Company is unable to determine what the outcome of the remaining Commission's proceedings will be, the amount of taxes, if any, plus interest and penalties that may ultimately be assessed against the purchaser and the claims, if any, that the purchaser might seek to assert against the Company in the event an unfavorable result is incurred by the purchaser. The Company has advised the purchaser that it believes the responsibility for the payment of the taxes, interest and penalty sought by the Commission, should it be ultimately determined that any such amounts are in fact owed, is the responsibility of the purchaser and not the Company.

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 judgements which would have a material adverse effect on the Company.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

The Company operates in the United States in three industry segments which are contract drilling, oil and natural gas exploration and production and natural gas marketing and processing. 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, 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
Natural gas marketing and processing	44,171	274	10,619	56	331
	87,124	$ 9,208	108,472	26,281	10,642
Other	834		3,949	708	132
Total	$ 87,958		$112,421	$ 26,989	$ 10,774
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
Natural gas marketing and processing	32,104	(221)	10,099	1,049	418
	70,853	$ 8,430	90,682	13,407	9,149
Other	88		5,080	323	107
Total	$ 70,941		$ 95,762	$ 13,730	$ 9,256
Year ended December 31, 1992:					
Drilling	$ 9,732	$(1,453)	$ 16,382	$ 266	$ 1,284
Oil and natural gas	23,464	8,798	61,694	7,951	7,128
Natural gas marketing and processing	21,970	(657)	7,628	541	250
	55,166	$ 6,688	85,704	8,758	8,662
Other	661		3,006	137	110
Total	$ 55,827		$ 88,710	$ 8,895	$ 8,772

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

(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 and furniture and equipment.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 1994 and 1993 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year ended December 31, 1994:				
Revenues	$ 23,005	$ 19,926	$ 21,166 (2)	$ 23,861
Gross Profit(1)	$ 2,396	$ 2,726	$ 2,090	$ 1,996
Income before income taxes	$ 1,215	$ 1,430	$ 1,595 (2)	$ 574
Net income	$ 1,211	$ 1,425	$ 1,590 (2)	$ 568
Net income per common share	$ .06	$ .07	$ .07 (2)	$ .03
Year ended December 31, 1993:				
Revenues	$ 15,574	$ 17,881	$ 16,935	$ 20,551
Gross Profit(1)	$ 2,357	$ 1,982	$ 1,920	$ 2,171
Income before income taxes	$ 1,163	$ 884	$ 890	$ 955
Net income	$ 1,156	$ 878	$ 886	$ 951
Net income per common share	$ 0.06	$ 0.04	$ 0.04	$ 0.05

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

(2) 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)		
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	$ 75,422
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
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

USA	Canada	Total

1992:	(In thousands)		
Capitalized costs:			
Proved properties	$ 117,721	$ 448	$ 118,169
Unproved properties	3,680	-	3,680
	121,401	448	121,849
Less accumulated depreciation, depletion, amortization and impairment	66,544	233	66,777
Net capitalized costs	$ 54,857	$ 215	$ 55,072
Cost incurred:			
Unproved properties	$ 504	$ -	$ 504
Producing properties	3,629	-	3,629
Exploration	900	-	900
Development	2,918	-	2,918
Total costs incurred	$ 7,951	$ -	$ 7,951

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)		
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

	USA	Canada	Total
	(In thousands)		
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
1992:			
Revenues	$21,816	$ 75	$21,891
Production costs	6,159	10	6,169
Depreciation, depletion and amortization	6,961	94	7,055

Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	$ 8,696	$ (29)	$ 8,667

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

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
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						
End of year						
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

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
1992:						
Proved developed and undeveloped reserves:						
Beginning of year	2,943	52,853	-	964	2,943	53,817
Revision of previous estimates	235	7,679	-	47	235	7,726
Extensions, discoveries and other additions	190	1,655	-	-	190	1,655
Purchases of minerals in place	316	8,327	-	-	316	8,327
Sales of minerals in place	(1)	(23)	-	-	(1)	(23)
Production	(375)	(6,730)	-	(80)	(375)	(6,810)
End of Year	3,308	63,761	-	931	3,308	64,692
Proved developed reserves:						
Beginning of year	2,778	44,936	-	499	2,278	45,435
End of year	3,245	58,809	-	468	3,245	59,277

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)		
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
1992			
Future cash flows	$208,964	$ 931	$209,895
Future production and development costs	86,417	361	86,778
Future income tax expenses	19,634	194	19,828
Future net cash flows	102,913	376	103,289
10% annual discount for estimated timing of cash flows	32,653	120	32,773
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 70,260	$ 256	$ 70,516

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

	USA	Canada	Total
	(In thousands)		
1994:			
Sales and transfers of oil and natural gas produced, net of production costs	$(16,953)	$ (48)	$(17,001)
Net changes in prices and production costs	(14,941)	206	(14,735)
Revisions in quantity estimates and changes in production timing	(482)	(5)	(487)
Extensions, discoveries and improved recovery, less related costs	17,050	-	17,050
Purchases of minerals in place	13,426	-	13,426
Sales of minerals in place	(138)	-	(138)
Accretion of discount	7,915	35	7,950

Net change in income taxes	(457)	(177)	(634)
Other - net	(554)	8	(546)
Net change	4,866	19	4,885
Beginning of year	73,152	231	73,383
End of year	$ 78,018	$ 250	$ 78,268
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

	USA	Canada	Total
		(In Thousands)	
1992:			
Sales and transfers of oil and natural gas produced, net of production costs	$(14,693)	$ (65)	$(14,758)
Net changes in prices and production costs	(1,081)	(117)	(1,198)
Revisions in quantity estimates and changes in production timing	4,113	2	4,115
Extensions, discoveries and improved recovery, less related costs	3,677	-	3,677
Purchases of minerals in place	9,488	-	9,488
Sales of minerals in place	(47)	-	(47)
Accretion of discount	6,602	49	6,651
Net change in income taxes	(2,870)	95	(2,775)
Other - net	2,104	5	2,109
Net change	7,293	(31)	7,262
Beginning of year	62,967	287	63,254
End of year	$ 70,260	$ 256	$ 70,516

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

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

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

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

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

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

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

Subsequent to December 31, 1994, the natural gas industry experienced a significant downturn in natural gas prices. The Company's reserves were determined at December 31, 1994 using a natural gas price of approximately $1.70 per Mcf for natural gas not subject to long-term contracts. At February 21, 1995, the natural gas prices received by the Company fell to approximately $1.41 per Mcf for natural gas not subject to long-term contracts. This decrease in natural gas prices would have had a significant effect on the SMOG value of the Company's reserves at December 31, 1994 and would have resulted in a provision to reduce the carrying value of oil and natural gas properties of approximately $3.5 million.

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, 1994 and 1993 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, 1994. 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, 1994 and 1993, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1994 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 22, 1995

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	67	Chairman of the Board, Chief Executive Officer and Director
John G. Nikkel	60	President, Chief Operating Officer and Director
Earle Lamborn	60	Senior Vice President, Drilling and Director
Philip M. Keeley	53	Senior Vice President, Exploration and Production
Larry D. Pinkston	40	Vice President, Treasurer and Chief Financial Officer
Mark E. Schell	37	General Counsel and Secretary

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

Mr. Nikkel joined the Company in 1983 as its President and a director. From 1976 until January 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of that Company from 1979 until his departure. Prior to joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike

Exploration Company. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Lamborn has been actively involved in the oil field for over 40 years, joining the Company's predecessor in 1952 prior to it becoming a publicly-held corporation. He was elected Vice President, Drilling in 1973 and to his current position as Senior Vice President and Director in 1979.

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

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

Mr. Schell joined the Company in January of 1987, as its Secretary and General Counsel. From 1979 until joining the Company, Mr. Schell was Counsel, Vice President and a member of the Board of Directors of C & S Exploration, Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa Law School.

The balance of the information required in this Item 10 is incorporated by reference to the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1995 annual meeting of stockholders.

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

Information required by this item is incorporated by reference to the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1995 annual meeting of stockholders.

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

Information required by this item is incorporated by reference to the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1995 annual meeting of stockholders.

Item 13. Certain Relationships and Related Transactions
- --

Information required by this item is incorporated by reference to the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 1995 annual meeting of stockholders.

PART IV

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

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:
- Consolidated Balance Sheets as of December 31, 1994 and 1993
- Consolidated Statements of Operations for the years ended December 31, 1994, 1993 and 1992
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 1994, 1993 and 1992
- Consolidated Statements of Cash Flows for the years ended December 31, 1994, 1993 and 1992
- 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, 1994, 1993 and 1992:
- Schedule VIII - Valuation and Qualifying Accounts and Reserves

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

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

3. Exhibits:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10.2.22* The Company's Stock Option Plan (filed 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 herewith).

10.3.4 Director and Officers Insurance and Company Reimbursement Policy (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).

10.5 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).

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:

On December 28, 1994 (as amended by Form 8-K/A filed February 24, 1995), the Company filed a report on Form 8-K under Item 2 and Item 5 reporting the purchase of certain oil and natural gas wells located in Oklahoma, Texas, New Mexico and Louisiana from Patrick Petroleum Corp of Michigan and American National Petroleum Company and the amending of the Company's credit agreement.

Schedule VIII

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, 1994	$ 411	$ -	$ 122	$ 289
Year ended December 31, 1993	$ 376	$ -	$ (35)	$ 411
Year ended December 31, 1992	$ 170	$ 200	$ (6)	$ 376

Deferred Tax Asset Valuation Allowance:

Balance at Balance at

Description	beginning of period	Additions	Deductions	end of period
		(In thousands)		
Year ended December 31, 1994	$ 8,218	$ -	$ 1,795	$ 6,423
Year ended December 31, 1993	$ 12,245	$ -	$ 4,027	$ 8,218
Year ended December 31, 1992	$ 12,905(1)	$ -	$ 660	$ 12,245

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(1) Represents initial valuation allowance recorded at the date of adoption of Statement of Financial Accounting Standard No. 109.

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 21, 1995 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 21st day of March, 1995.

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 STANLEY W. BELITZ	Controller
/s/ Don Bodard DON BODARD	Director
/s/ Don Cook DON COOK	Director
/s/ William B. Morgan WILLIAM B. MORGAN	Director

/s/ John S. Zink JOHN S. ZINK	Director
/s/ John H. Williams JOHN H. WILLIAMS	Director

EXHIBIT INDEX

Exhibit No.	Description	Page
10.2.28	Unit 1995 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	