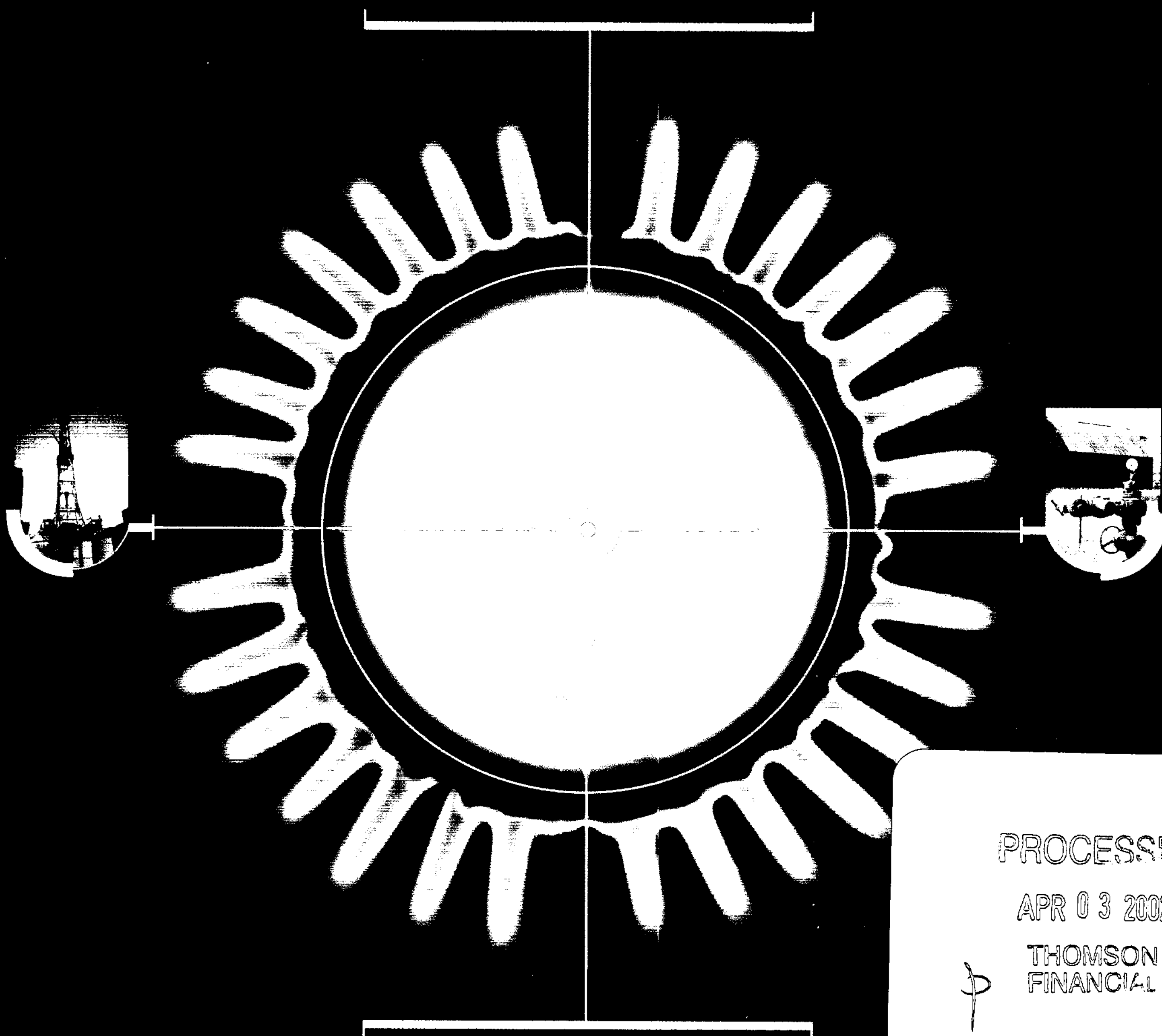
UNIT CORPORATION



2001 ANNUAL REPORT

CORPORATE PROFILE

Unit Corporation is a diversified energy company engaged, through its subsidiaries, in the exploration and production of oil and natural gas, the acquisition of producing oil and natural gas properties and the contract drilling of onshore oil and natural gas wells. Our operations are principally located in the Mid-Continent, Rocky Mountain and Gulf Coast Basins. Our corporate offices are located in Tulsa, Oklahoma, with regional offices in Oklahoma City, Oklahoma; Woodward, Oklahoma; Booker, Texas; Houston, Texas and Casper, Wyoming. Our common stock trades on the New York Stock Exchange under the symbol "UNT".

TABLE OF CONTENTS

THREE-YEAR FINANCIAL AND OPERATIONAL SUMMARY

Year Ended December 31,		1999(1)		2000			2001
SELECTED FINANCIAL DATA							
Revenues	$	102,352,000	$	201,264,000	29%	**$**	**259,179,000**
Net Income	$	3,048,000	$	34,344,000	83%	**$**	**62,766,000**
Net Income per Common Share (Diluted)	$	0.10	$	0.95	82%	**$**	**1.73**
Total Assets	$	295,567,000	$	346,288,000	20%	**$**	**417,253,000**
Long-Term Debt	$	67,239,000	$	54,000,000	-43%	**$**	**31,000,000**
Shareholders' Equity	$	179,505,000	$	214,540,000	30%	**$**	**279,162,000**
Cash Flows from Operations Before Changes in Working Capital	$	29,111,000	$	85,421,000	54%	**$**	**131,381,000**
Weighted Average Shares Outstanding (Diluted)		29,913,000		36,132,000	0%		**36,258,000**
SELECTED OPERATIONAL DATA							
Future Net Revenue from Proved Reserves (2):							
Unescalated and Undiscounted	$	344,944,000	$	1,779,618,000	-78%	**$**	**397,191,000**
Discounted at 10% Before Income Taxes	$	199,224,000	$	1,001,581,000	-77%	**$**	**231,193,000**
Net Estimated Proved Reserves:							
Natural Gas (Thousand Cubic Feet)		187,339,000		215,637,000	6%		**228,254,000**
Oil (Barrels)		4,527,000		4,183,000	4%		**4,343,000**
Equivalent Natural Gas (Thousand Cubic Feet)		214,501,000		240,737,000	6%		**254,309,000**
Net Production:							
Natural Gas (Thousand Cubic Feet)		17,437,000		19,285,000	-2%		**18,864,000**
Oil (Barrels)		424,000		488,000	1%		**492,000**
Equivalent Natural Gas (Thousand Cubic Feet)		19,981,000		22,215,000	-2%		**21,819,000**
Gross Wells Producing or Capable of Producing		2,797		2,951	3%		**3,038**
Net Wells Producing or Capable of Producing		629.2		710.8	4%		**738.0**
Average Price Received:							
Natural Gas (Per Thousand Cubic Feet)	$	2.05	$	3.91	2%	**$**	**4.00**
Oil (Per Barrel)	$	17.48	$	26.95	-12%	**$**	**23.62**
Number of Drilling Rigs at Year End		47 *(3)*		50 *(4)*	10%		**55 *(5)***
Average Number of Rigs Utilized		23.1		39.8	16%		**46.3**
SELECTED FUNDAMENTAL ANALYSIS							
Production Replacement *(6)*		171%		311%	-48%		**161%**
Production Expense per Mcfe	$	0.59	$	0.74	16%	**$**	**0.86**
DD&A Rate per Mcfe	$	0.85	$	0.82	11%	**$**	**0.91**

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

(2) Future net revenues on proved reserves at 12/31/2000 were higher than other years due to high year-end spot prices used to compute the value of the reserves.

(3) Thirteen rigs were acquired on September 30, 1999.

(4) Includes one rig that was acquired at the 2000 year end and two rigs that were completing construction.

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

(6) Excludes Questa in 1999.

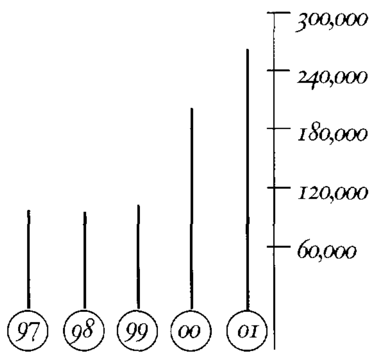
LETTER TO THE SHAREHOLDERS

Volatile oil and natural gas prices are a certainty in our industry and this was once again demonstrated during 2001. The average natural gas price we received peaked in January at $9.35 per Mcf then fell to a low $2.05 per Mcf during September. This volatility was compounded by the tragic terrorist attacks that occurred on September 11th. These events shocked our nation and created even more uncertainty about the world we live in and about the energy supplies we rely on. Given this uncertainty, it is important that we remain focused on the things we can control. For us, this includes three vital aspects of our business; the size, scope and quality of our drilling rig fleet; our oil and natural gas reserve base and our capital structure including debt levels.

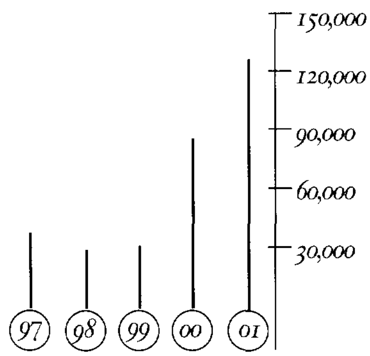
We have continued to focus on activities that enhance the value of our company since our inception in 1963. Our contract drilling subsidiary, Unit Drilling Company, achieved a milestone by increasing its drilling rig fleet from 50 to 55 rigs, the largest fleet in its history. Our fleet is capable of drilling wells as deep as 40,000 feet and has one of the deepest average depth capacities in the industry at 17,500 feet. The quality of our rigs and of our drilling crews is a significant factor that keeps our fleet busy and profitable. Of our 55 rigs, 54 are operational and for a brief time in August, all were drilling, a goal seldom achieved even under ideal circumstances.

Our exploration and production subsidiary, Unit Petroleum Company, attained record reserves of 4.3 million barrels of oil and 228.3 Bcf of natural gas, a 6 percent increase in equivalent Mcf over 2000. For the eighteenth consecutive year, we replaced more than 150 percent of our production with new reserves. We are proud of our record of consistent performance, which we believe, is unmatched in the industry.

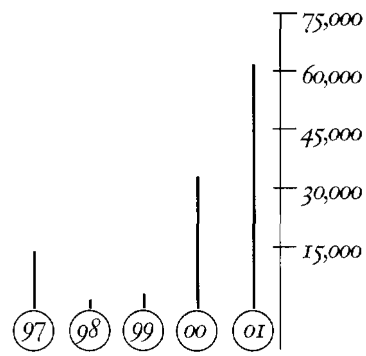
Unit is structured to be profitable even in times of very low commodity prices. Because of this, our financial results were outstanding in 2001, when the average price we received for natural gas was $4.00 per Mcf. Total revenues increased 29 percent over last year, while year-over-year earnings per share rose 82 percent to $1.73 per diluted share. Cash flow from operations before changes in working capital improved 54 percent compared to the prior year. We used our cash flow to improve our asset base as well as our capital structure. We repaid $23 million of our long-term debt, reducing our debt-to-capitalization ratio to 10 percent. With a



TOTAL REVENUES
thousands of dollars



CASH FLOW
(from operations before changes in working capital) thousands of dollars



NET INCOME
thousands of dollars

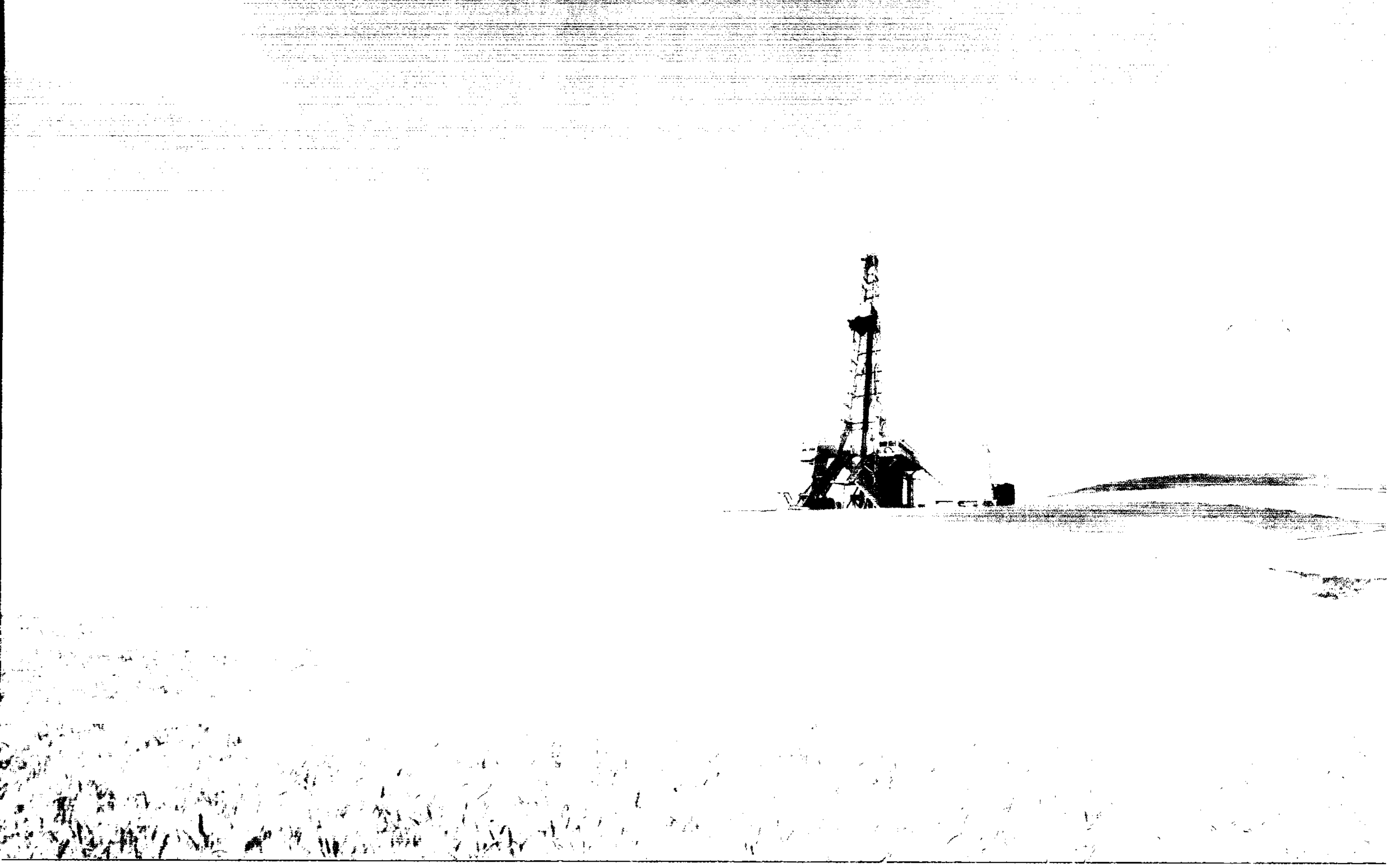
strong balance sheet and $30 million available on our line of credit, we are seeking growth opportunities for both of our primary business segments.

Most analysts believe that the North American natural gas market will be weak until mid-2002 when an improving economy begins to spur demand. The slow down of drilling activity that is currently underway is expected to reduce supply in the latter half of the year. That reduction of natural gas supply should improve future commodity prices thereby stimulating rig utilization rates and dayrates. We are highly leveraged to natural gas. Ninety percent of our oil and natural gas reserves are natural gas and nearly all of our contract drilling operations are natural gas projects. If conditions continue on the current course, we expect that dayrates will continue to decline early in the first quarter and then stablize along with utilization for the remainder of the first half of 2002 and improve thereafter. In anticipation of improved natural gas prices, we will maintain an aggressive corporate drilling program through the first half of 2002 and adjust our drilling efforts for the remainder of the year based on market conditions.

As we look forward to 2002, we will continue to focus on the things we can control. We will seek opportunities to expand our drilling rig fleet as appropriate. We will continue to grow our oil and natural gas operations by increasing our reserve base. And, we will continue to improve our balance sheet by controlling debt and increasing our borrowing capacity as we search for appropriate acquisition candidates. We have learned to adapt to the many fluctuations in our industry and as a result we have been able to grow and even flourish in times of decline. Our conservative approach works as our consistent performance proves. We eagerly anticipate the challenges and the opportunities ahead.

Sincerely,

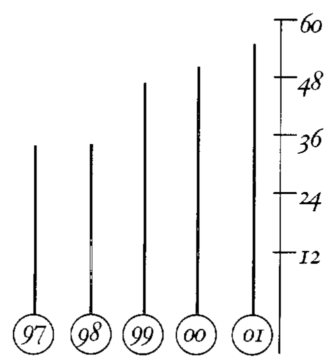
John G. Nikkel
President and Chief Executive Officer
February 20, 2002



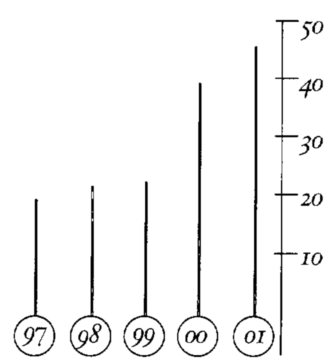
UNIT DRILLING COMPANY

Unit Drilling Company has a 39-year history of providing outstanding service to its customers, expanding from our originating areas within the Anadarko and Arkoma Basins to the Gulf Coast, East Texas and Rocky Mountain regions.

It has grown from a three-rig drilling company to its current drilling rig fleet of 55.



DRILLING RIGS OWNED
Number at year end



RIG UTILIZATION
Average number during the year

From our beginning in 1963, Unit Drilling Company has a 39-year history of providing outstanding service to its customers with experienced supervisors, rig personnel and quality equipment, all positioned to meet a wide range of drilling needs.

During 2001, Unit increased its rig fleet to 55 drilling rigs, an increase of 5 rigs during the year. These rigs range in depth capacities from 9,500 to 40,000 feet and can provide both vertical and horizontal services using both air and mud as a drilling medium. We also own four top-drive units to help support our customer's unique drilling requirements.

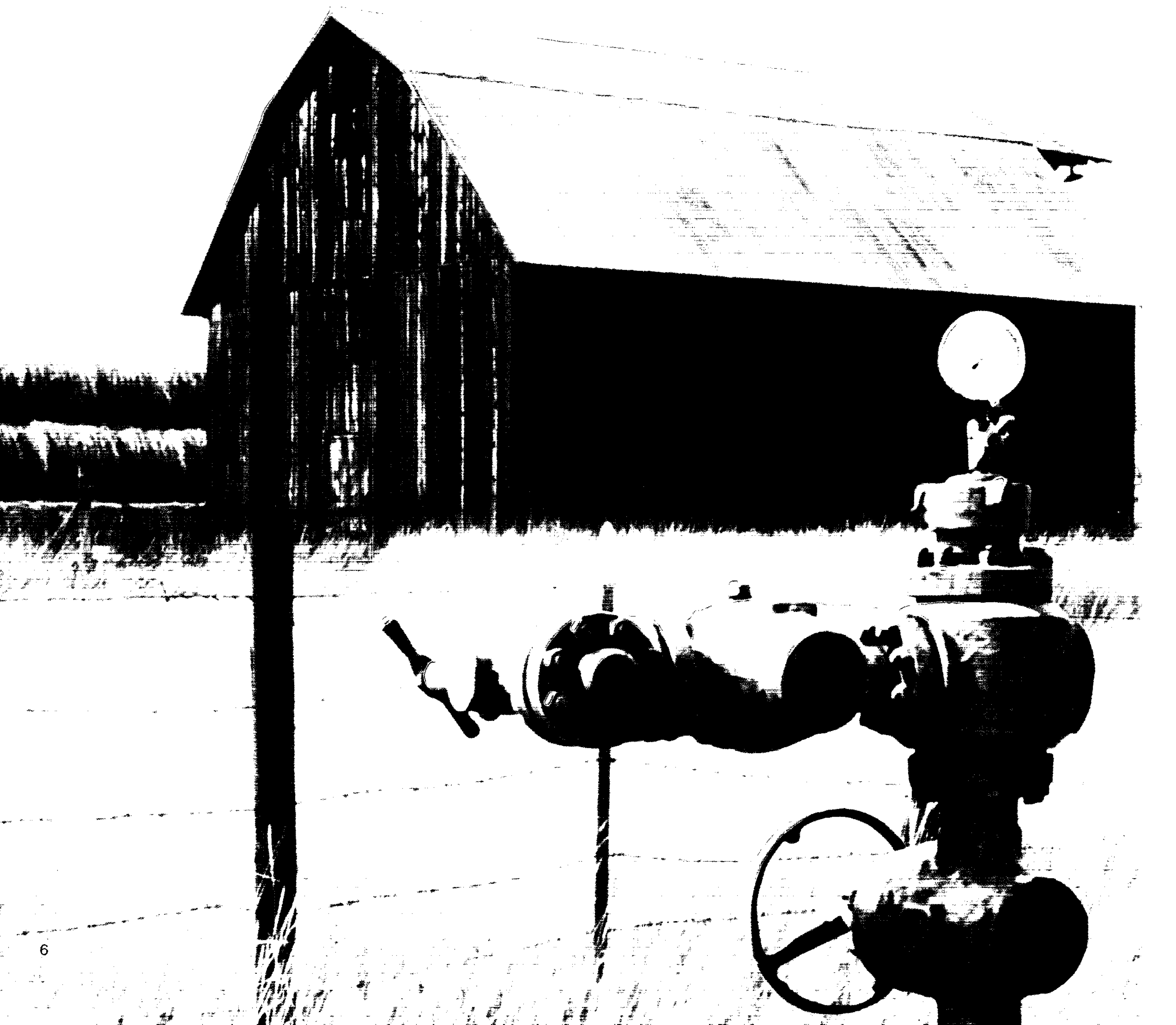
Currently, the fleet is located within four areas within the Mid-Continent region of the United States. Twenty-nine rigs are located in the Anadarko Basin, 6 rigs in the Arkoma Basin, 12 rigs located within our Gulf Coast operations and 8 rigs in our Rocky Mountain region. Drilling field offices are located in Oklahoma City and Woodward, Oklahoma; Houston, Texas and Casper, Wyoming.

Our average rig utilization for the year was 46.3 rigs, a 16 percent improvement over 2000. Drilling revenues for the year increased 55 percent to $167.0 million, while average dayrates for the year on our daywork contracts rose 44 percent to an average dayrate for the year of $10,044. Correspondingly, contract drilling operating margins increased to 46 percent, compared to 22 percent during 2000. This sharp increase was due to the elevated commodity prices during the first quarter of 2001.

As industry conditions cycled down from an over-heated first half, our rig utilization followed. During the fourth quarter of 2001, we averaged 38.8 rigs operating, an 11 percent decrease from the fourth quarter of 2000. We exited the year with 32 rigs operating. Currently, 34 of our rigs are operating under contract. It appears that utilization is stabilizing as we await natural gas demand improvement.

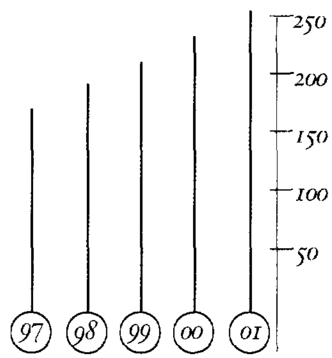
We look forward to 2002 with the anticipation of continuing to expand our operations and responding with confidence to any conditions this industry throws our way.

UNIT PETROLEUM COMPANY

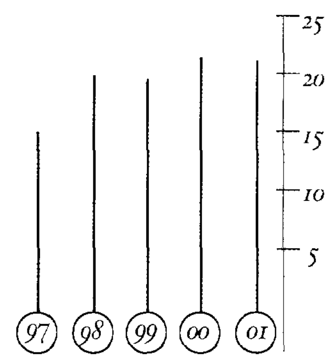


We focus on drilling low-risk development and exploitation wells and we drive our oil and natural gas reserve growth through drilling internally generated prospects along with opportunistic acquisitions.

With this strategy, we have consistently been able to expand our operations and grow our asset base.



TOTAL RESERVES
Bcfe of natural gas (1997-1999 does not include Questa)



ANNUAL PRODUCTION
Bcfe of natural gas (1997-1999 does not include Questa)

Unit Petroleum Company continues to grow and demonstrate its ability to expand its asset base regardless of volatile industry conditions. We have a proven success record of drilling prospects generated by our geological and engineering staff that are low risk field extension or development wells that meet our risk-weighted economic objectives. Our low cost development drilling success has resulted in an average annual growth rate of 20 percent to our reserve base over the past 18 years.

As of December 31, 2001, total reserves were 254.3 Bcfe, consisting of 4.3 million barrels of oil and 228.3 Bcf of natural gas, a 6 percent equivalent increase over year-end 2000 reserves. We added a net 35.4 Bcfe of new reserves during the year, marking 18 consecutive years that we have met our goal of replacing at least 150 percent of the year's production with new reserves. Our three-year average finding cost was $0.93 per Mcfe. We are proud of our ability to economically grow our reserves.

During 2001, we completed 125 wells, a 24 percent increase from 2000. Eighty-two percent of the 125 wells were completed as producing wells. We are pleased with these results in the face of limited rig availability, tight supply of completion rigs, and substantially delayed well connections.

Oil and natural gas revenues decreased 2 percent to $90.2 million due to the depressed commodity prices and modestly lower production during the latter part of the year. Our natural gas prices averaged $4.00 per Mcf, a 2 percent increase from 2000, while oil prices averaged $23.62 per barrel, a 12 percent decrease from the previous year. Total production decreased approximately 2 percent as we experienced steeper than normal production declines in recently drilled wells.

We produced 18,864,000 Mcf of natural gas, a 2 percent decrease. Oil production increased 1 percent to 492,000 barrels.

Our acreage inventory, the bulk of which is held by production, has grown to 725,000 gross acres. We have identified a possible 381 drillable wells with potential net reserves to us of some 210 Bcfe.

For the year 2002, we intend to continue an aggressive drilling effort with a budget 14 percent higher than what we expended in 2001. We are hopeful that lower natural gas prices early in the year will bring us some acquisition opportunities. In either case, we will closely monitor natural gas prices and adjust our plans accordingly.

DIRECTORS AND OFFICERS

BOARD OF DIRECTORS

King P. Kirchner
Chairman of the Board

John G. Nikkel
President and Chief Executive Officer

Earle Lamborn
Senior Vice President, Drilling

John H. Williams
Investments
Tulsa, Oklahoma

Don Cook
Retired Partner, Finley & Cook
Certified Public Accountants
Shawnee, Oklahoma

William B. Morgan
Executive Vice President and
General Counsel of
St. John Health Systems, Inc.
Tulsa, Oklahoma

John S. (Jack) Zink
Founder, Zeeco, Inc.
Tulsa, Oklahoma

J. Michael Adcock
Chairman of the Board of Arvest Bank
Shawnee, Oklahoma

OFFICERS

King P. Kirchner
Chairman of the Board

John G. Nikkel
President and Chief Executive Officer

Earle Lamborn
Senior Vice President, Drilling

Philip M. Keeley
Senior Vice President, Exploration and Production

Larry D. Pinkston
Vice President, Treasurer and
Chief Financial Officer

Mark E. Schell
General Counsel and Secretary

INDEPENDENT ACCOUNTANTS

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

INDEPENDENT RESERVIOR ENGINEERS

Ryder Scott Company
Houston, Texas

AUDIT COMMITTEE

Don Cook
William B. Morgan
John S. (Jack) Zink
J. Michael Adcock

NOMINATING COMMITTEE

(formed effective January 1, 2002)
William B. Morgan
John H. Williams
John S. (Jack) Zink

COMPENSATION COMMITTEE

Don Cook
John H. Williams
J. Michael Adcock
John S. (Jack) Zink

FINANCIAL INFORMATION

UNIT CORPORATION AND SUBSIDIARIES

SELECTED FINANCIAL AND OPERATIONS DATA

Year Ended December 31, (Dollars in thousands except per share amounts)	1997(1)	1998(1)	1999(1)	2000	2001
Statement of Operations Data:					
Revenues:					
Contract drilling	$ 46,199	$ 53,528	$ 55,479	$ 108,075	$ 167,042
Oil and natural gas	$ 49,939	$ 43,346	$ 46,225	$ 92,016	$ 90,237
Net income	$ 12,330	$ 1,428	$ 3,048	$ 34,344	$ 62,766
Net income per common share:					
Basic	$ .47	$ .05	$ .10	$ .96	$ 1.75
Diluted	$ .46	$ .05	$ .10	$ .95	$ 1.73
Balance Sheet Data:					
Total assets	$ 213,416	$ 233,096	$ 295,567	$ 346,288	$ 417,253
Other long-term liabilities	$ 2,363	$ 2,368	$ 2,325	$ 3,597	$ 4,110
Long-term debt	$ 55,480	$ 75,048	$ 67,239	$ 54,000	$ 31,000
Shareholders' equity	$ 115,843	$ 117,384	$ 179,505	$ 214,540	$ 279,162
Statement of Cash Flows Data:					
Net cash provided by operating activities	$ 36,993	$ 35,231	$ 24,713	$ 67,360	$ 133,021
Capital expenditures (cash basis)	$ 47,915*(2)*	$ 56,290	$ 69,503*(3)*	$ 60,447	$ 108,339
Contract Drilling Operations Data:					
Number of rigs at year end	34*(4)*	34	47*(5)*	50*(6)*	55*(7)*
Wells drilled	167	198	197	316	361
Total footage drilled (feet in 1,000's)	1,736	2,203	2,211	3,650	4,008
Average number of rigs utilized	20.0	22.9	23.1	39.8	46.3
Oil and Natural Gas Operations Data:					
Unescalated proved oil and natural gas reserves discounted at 10% (before income taxes)	$ 178,186	$ 144,327	$ 199,224	$ 1,001,581*(8)*	$ 231,193
Total estimated proved reserves:					
Natural gas (MMcf)	159,735	176,407	187,339	215,637	228,254
Oil (MBbl)	4,596	3,629	4,527	4,183	4,343
Production:					
Natural gas (MMcf)	14,995	17,732	17,437	19,285	18,864
Oil (MBbl)	535	486	424	488	492
Average price:					
Natural gas (per Mcf)	$ 2.40	$ 1.91	$ 2.05	$ 3.91	$ 4.00
Oil (per Bbl)	$ 19.18	$ 12.77	$ 17.48	$ 26.95	$ 23.62
Oil and natural gas wells producing or capable of producing at end of year:					

	1997 Gross	1997 Net	1998 Gross	1998 Net	1999 Gross	1999 Net	2000 Gross	2000 Net	2001 Gross	2001 Net
Natural gas	1,779	328.3	2,024	372.3	2,014	405.1	2,152	432.7	2,252	459.0
Oil	801	215.3	841	214.7	783	224.1	799	278.1	786	279.0
Total	2,580	543.6	2,865	587.0	2,797	629.2	2,951	710.8	3,038	738.0

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

(2) Through our acquisition of Hickman Drilling Company for stock and notes payable, Unit also had non-cash capital additions of $23,187,000.

(3) Through our acquisition of the thirteen Parker rigs, Unit had non-cash capital additions of $8,138,000 for the 1,000,000 shares given as a portion of the consideration for the rigs.

(4) Ten rigs were acquired in the fourth quarter of 1997.

(5) Thirteen rigs were acquired on September 30, 1999.

(6) Includes one rig that was acquired at the 2000 year end and two rigs that were completing construction.

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

(8) Future net revenues on proved reserves at 12/31/2000 were higher than other years due to high year-end spot prices used to compute the value of the reserves.

MARKET FOR UNIT CORPORATION'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

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

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

On February 20, 2002 there were 1,985 record holders of our common stock.

We have never paid cash dividends on our common stock and currently intend to continue our policy of retaining earnings from our operations. Our loan agreement prohibits us from declaring and paying dividends (other than stock dividends) in any fiscal year in an amount greater than 25 percent of our preceding year's consolidated net income and then only if our working capital provided from operations for the previous year was equal to or greater than 175 percent of the current maturities of our long-term debt at the end of the previous year.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

With the exception of historical information, the matters discussed below may include forward-looking statements regarding our operations, financial and otherwise. We caution you that a number of important factors could cause the actual results of our future operations to differ materially from those in any forward-looking statements. Further information regarding these factors are discussed at "Safe Harbor Statement Under the Private Securities Litigation Reform Act" on page 17.

FINANCIAL CONDITION AND LIQUIDITY

Our financial condition and liquidity, for current operations, depends on our cash flow from operating activities and borrowings under our bank loan agreement. Our cash flow is influenced mainly by the prices we receive for our natural gas production, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production. Our loan agreement provides for a revolving credit facility, which terminates on May 1, 2005 followed by a three-year term loan. At December 31, 2001, we had borrowed $30 million, which was 50 percent of the amount available, as elected by us on October 1, 2001, and represented 30 percent of the loan value of our assets as determined by our banks on October 1, 2001. Most of our capital expenditures are discretionary and directed toward future growth.

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

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

Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

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

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

We entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 natural gas production at a floor price of $4.50 and a ceiling price of $5.95. We also entered into two natural gas collar contracts for approximately 38 percent of our September through November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. For the year our natural gas collar contracts added $2,030,000 to our natural gas revenues. We did not have any hedging transactions outstanding at December 31, 2001 nor on February 20, 2002.

Contract Drilling Operations. Our drilling operations are subject to many factors that influence the number of rigs we have working at any one time as well as the costs and revenues associated with such work. These factors include competition from other drilling contractors, the prevailing prices for natural gas and oil, the availability of labor to operate our rigs and our ability to supply the type of equipment required. We have not encountered major difficulty in hiring and retaining rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs was to increase rapidly in the future, shortages of experienced personnel would limit our ability to increase the number of rigs we could operate.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	2 - 3 Years	4 - 5 Years	After 5 Years
(In thousands)					
Bank Debt *(1)*	$ 30,000	$ —	$ —	$ 15,833	$ 14,167
Hickman Note *(2)*	2,000	1,000	1,000	—	—
Retirement Agreement *(3)*	1,330	20	470	600	240
Gas Purchaser Prepayment (4)	437	437	—	—	—
Operating Leases *(5)*	2,306	654	1,296	344	12
Total Contractual Obligations	$ 36,073	$ 2,111	$ 2,766	$ 16,777	$ 14,419

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

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

(3) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, will be paid in $25,000 monthly payments starting in July 2003 and continuing through June 2009 (See Note 4 of our Consolidated Financial Statements).

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

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

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

		Amount of Commitment Expiration Per Period			
Other Commitments	Total Amount Committed or Accrued	Less Than 1 Year	2 - 3 Years	4 - 5 Years	After 5 Years
(In thousands)					
Deferred Compensation Agreement *(1)*	$ 1,277	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement *(2)*	$ 1,959	$ 436	Unknown	Unknown	Unknown
Repurchase Obligations *(3)*	Unknown	Unknown	Unknown	Unknown	Unknown

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities on our Consolidated Balance Sheet, at the time of deferral (See Note 6 of our Consolidated Financial Statements).

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan (See Note 6 of our Consolidated Financial Statements).

(3) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2002, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of each year. These partnership agreements require, upon the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20 percent of the units outstanding. We made repurchases of $10,000 and $14,000 in 1999 and 2000, respectively, for such limited partners' interests. No repurchases were made in 2001 (See Note 9 of our Consolidated Financial Statements).

Oil and Natural Gas Limited Partnerships. We are the general partner for eighteen oil and natural gas partnerships which were formed privately and publicly. The partnership's revenues and costs are shared in accordance with formulas prescribed in each limited partnership agreement. The partnerships reimburse us for contract drilling, well supervision and general and administrative expense reimbursements. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable. During 1999, 2000 and 2001, the total paid to us for all of these fees was $694,000, $966,000 and $1,107,000, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

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

At December 31, 2001, one of our subsidiaries owned 4,949,500 shares of common stock and 1,800,000 warrants of Shenandoah Resources Ltd., a Canadian oil and natural gas exploration and production company. The investment of $346,000 is part of other assets in our consolidated balance sheet and was written down by $2.1 million during 2001.

Critical Accounting Policies. *We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized.* At the end of each quarter, the net capitalized costs of our oil and natural gas properties is limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (10 percent discount rate) of estimated future net revenues from proved reserves, based on period-ending oil and natural gas prices, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized less related income tax. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a non-cash charge to earnings. If required, it reduces earnings and impacts stockholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the probability of a ceiling test writedown. Based on oil and natural gas prices in effect on December 31, 2001 ($2.51 per Mcf for natural gas and $17.71 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas pricing has been erratic since year-end and any significant declines below year-end prices used in the reserve evaluation would likely result in a ceiling test write-down in subsequent quarterly reporting periods.

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

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

Under "footage" and "turnkey" contracts, we bear the risk of completion of the well, so revenues and expenses are recognized using the completed contract method. The entire amount of a loss, if any, is recorded when the loss can be determined. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

EFFECTS OF INFLATION

In the 18 years prior to the last half of 1999, the effects of inflation on our operations was minimal due to low inflation rates and moderate demand for contract drilling services. However, starting in the last half of 1999 and throughout 2000 and the first three quarters of 2001, as drilling rig dayrates and utilization increased, the impact of inflation increased as the availability of used equipment and third party services decreased. Due to industry-wide demand for qualified labor, contract drilling labor costs increased substantially in the summer of 2000 and once again in the summer of 2001. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates and the prices we receive for our oil and natural gas. If industry activity recovers and returns to levels achieved in early 2001, shortages in support equipment such as drill pipe, third party services and qualified labor could occur resulting in additional corresponding increases in our material and labor costs. These conditions may limit our ability to realize improvements in operating profits.

NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2001, we adopted Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No.'s 137 and 138), "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This statement requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we are required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change. We periodically enter into derivative commodity instruments to hedge our exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists. At December 31, 2001, we were not holding any natural gas or oil derivative contracts.

On July 20, 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142). For goodwill and intangible assets already recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. We expensed $243,000 annually for the amortization of goodwill, and the unamortized balance of goodwill is $5,088,000 at December 31, 2001. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for us). We do not believe the future impact from the adoption of FAS 142 on our financial position or results of operation will be material.

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

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

RESULTS OF OPERATIONS

2001 versus 2000

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

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

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

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

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

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

General and administrative expenses increased 29 percent. In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense plus accrued interest will be paid in $25,000 monthly payments starting in July 2003 and continuing through June 2009. Interest expense decreased 45 percent as our average outstanding debt decreased 28 percent during 2001. The average interest rate decreased from 7.9 percent in 2000 to 5.7 percent in 2001.

2000 versus 1999

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

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

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

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

Our contract drilling operating margins increased from 14 percent in 1999 to 22 percent in 2000. The additional operating margin was generally due to additional revenue received per day and an increase in the number of rigs utilized. Our contract drilling operating cost per rig day increased $109 in 2000 as total contract drilling operating costs were up 76 percent in 2000 versus 1999 primarily due to increased utilization.

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

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

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

SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT

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

These forward-looking statements include, among others, such things as the amount and nature of future capital expenditures, the number of wells to be drilled or reworked, oil and natural gas prices and demand, exploration prospects, estimates of proved oil and natural gas reserves, reserve potential, development and infill drilling potential, drilling prospects, expansion and other development trends of the oil and natural gas industry, business strategy, production of oil and natural gas reserves, expansion and growth of our business and operations, and drilling rig utilization, revenues and costs.

These statments are based on certain assumptions and analysis made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including the risk factors discussed in this document, general economic, market or business conditions, the nature or lack of business opportunities that may be presented to and pursued by us, demand for land drilling services, changes in laws or regulations, and other factors, most of which are beyond our control. We disclaim any obligation to update or revise any forward-looking statement to reflect events or circumstances occurring hereafter or to reflect the occurence of anticipated or unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the Securities and Exchange Commission. We encourage you to obtain and read that document.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, prices we have received for our oil and natural gas production have been volatile and such volatility is expected to continue. The price of natural gas also effects the demand for our rigs and the amount we can charge for the use of the rigs. Based on our 2001 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $146,000 per month ($1,752,000 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $33,000 per month ($396,000 annualized) change in our pre-tax cash flow.

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

We entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 natural gas production at a floor price of $4.50 and a ceiling price of $5.95. We also entered into two natural gas collar contracts for approximately 38 percent of our September through November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. For the year our natural gas collar contracts added $2,030,000 to our natural gas revenues. We did not have any hedging transactions outstanding at December 31, 2001 nor on February 20, 2002.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the prime rate or the London Interbank Offered Rate ("Libor rate"). At our election, borrowings under our revolving credit and term loan may be fixed at the Libor rate for periods up to 180 days. Historically, we have not utilized any financial instruments, such as interest rate swaps, to manage our exposure to increases in interest rates. However, we may use such financial instruments in the future should our assessment of future interest rates warrant such use. Based on our average outstanding long-term debt in 2001, a one percent change in the floating rate would change our annual cash flow before income taxes by approximately $450,000.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2000	2001
(In thousands)		
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 726	$ 391
Accounts receivable (less allowance for doubtful accounts of $919 and $604)	40,220	33,886
Materials and supplies	3,802	5,358
Income tax receivable	—	3,198
Prepaid expenses and other	1,269	3,761
Total current assets	46,017	46,594
Property and Equipment:		
Drilling equipment	196,736	244,698
Oil and natural gas properties, on the full cost method	349,707	406,491
Transportation equipment	5,803	6,441
Other	8,801	9,231
	561,047	666,861
Less accumulated depreciation, depletion, amortization and impairment	270,690	304,643
Net property and equipment	290,357	362,218
Other Assets	9,914	8,441
Total Assets	$ 346,288	$ 417,253
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities	$ 1,627	$ 1,893
Accounts payable	21,012	16,292
Accrued liabilities	9,854	10,616
Contract advances	179	240
Total current liabilities	32,672	29,041
Long-Term Debt	54,000	31,000
Other Long-Term Liabilities (Note 4)	3,597	4,110
Deferred Income Taxes	41,479	73,940
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 75,000,000 shares authorized, 35,768,344 and 36,006,267 shares issued, respectively	7,154	7,201
Capital in excess of par value	139,872	141,977
Retained earnings	67,514	130,280
Treasury stock at cost (30,000 shares)	—	(296)
Total shareholders' equity	214,540	279,162
Total Liabilities and Shareholders' Equity	$ 346,288	$ 417,253

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

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

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

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

Year Ended December 31, 1999, 2000 and 2001 (In thousands) (1999 Restated, See Note 2)	COMMON STOCK	CAPITAL IN EXCESS OF PAR VALUE	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME	TREASURY STOCK	TOTAL
BALANCES, JANUARY 1, 1999	$ 5,478	$ 81,915	$ 30,122	$ —	$ (131)	$ 117,384
Net income	—	—	3,048	—	—	3,048
Activity in employee compensation plans (252,511 shares)	50	680	—	—	131	861
Sale of common stock (7,000,000 shares)	1,400	48,682	—	—	—	50,082
Issuance of stock for acquisition (1,000,000 shares)	200	7,938	—	—	—	8,138
Questa purchase of treasury shares	—	(8)	—	—	—	(8)
BALANCES, DECEMBER 31, 1999	7,128	139,207	33,170	—	—	179,505
Net income	—	—	34,344	—	—	34,344
Activity in employee compensation plans (135,419 shares)	26	665	—	—	—	691
BALANCES, DECEMBER 31, 2000	7,154	139,872	67,514	—	—	214,540
Net income	—	—	62,766	—	—	62,766
Activity in employee compensation plans (237,923 shares)	47	2,105	—	—	—	2,152
Purchase of treasury shares (30,000 shares)	—	—	—	—	(296)	(296)
Other comprehensive income (net of tax):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	—	1,258	—	1,258
Adjustment reclassification- derivative settlements	—	—	—	(1,258)	—	(1,258)
BALANCES, DECEMBER 31, 2001	$ 7,201	$ 141,977	$ 130,280	$ —	$ (296)	$ 279,162

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, (In thousands)	1999 (Restated, See Note 2)	2000	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 3,048	$ 34,344	$ 62,766
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization, and impairment	24,285	30,946	36,642
Equity in net earnings of unconsolidated subsidiary	—	—	(1,148)
Loss (gain) on disposition of assets	(400)	(969)	(56)
Employee stock compensation plans	436	443	2,873
Bad debt expense	255	350	—
Deferred tax expense	1,487	20,307	30,304
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(8,450)	(18,500)	6,334
Materials and supplies	49	(543)	(1,556)
Prepaid expenses and other	140	(96)	(3,533)
Accounts payable	2,667	(1,370)	(155)
Accrued liabilities	1,590	3,067	929
Contract advances	48	(179)	61
Other liabilities	(442)	(440)	(440)
Net cash provided by operating activities	24,713	67,360	133,021
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures (including producing property acquisitions)	(69,503)	(60,447)	(108,339)
Proceeds from disposition of property and equipment	1,438	4,259	2,631
(Acquisition) disposition of other assets	91	(2,656)	17
Net cash used in investing activities	(67,974)	(58,844)	(105,691)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under line of credit	61,600	31,200	57,200
Payments under line of credit	(68,400)	(44,439)	(79,200)
Net payments on notes payable and other long-term debt	(1,090)	(556)	(1,000)
Proceeds from sale of common stock	50,136	250	609
Book overdrafts (Note 1)	2,974	3,108	(4,978)
Acquisition of treasury stock	—	—	(296)
Net cash provided by (used in) financing activities	45,220	(10,437)	(27,665)
Net Increase (Decrease) in Cash and Cash Equivalents	1,959	(1,921)	(335)
Cash and Cash Equivalents, Beginning of Year	688	2,647	726
Cash and Cash Equivalents, End of Year	$ 2,647	$ 726	$ 391
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the year for:			
Interest	$ 5,850	$ 5,135	$ 2,807
Income taxes	$ 30	$ 519	$ 7,779

See Note 2 for non-cash investing activities.

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

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

Drilling Contracts. Unit recognizes revenues generated from "daywork" drilling contracts as the services are performed, which is similar to the percentage of completion method. Under "footage" and "turnkey" contracts, Unit bears the risk of completion of the well therefore, revenues and expenses are recognized using the completed contract method. The duration of all three types of contracts range typically from 20 to 90 days, but some of our daywork contracts in the Rocky Mountains can range up to one year. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

Cash Equivalents and Book Overdrafts. Unit includes as cash equivalents, certificates of deposits and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued prior to the end of the period, but not presented to Unit's bank for payment prior to the end of the period. At December 31, 2000 and 2001, book overdrafts of $6.1 million and $1.1 million have been included in accounts payable.

Property and Equipment. Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives, including a minimum provision of 20 percent of the active rate when the equipment is idle. Unit uses the composite method of depreciation for drill pipe and collars and calculates the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

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

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

Goodwill. Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company over the fair value of the net assets acquired and is being amortized on the straight-line method using a 25 year life through December 31, 2001. On July 20, 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142). For goodwill and intangible assets recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). We do not believe the future impact from the adoption of FAS 142 on our financial position or results of operation will be material. Net goodwill reported in other assets at December 31, 2000 and 2001 was $5,331,000 and $5,088,000, respectively with accumulated amortization at December 31, 2000 and 2001 of $750,000 and $993,000, respectively.

Oil and Natural Gas Operations. Unit accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Unit capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities. Independent petroleum engineers annually review Unit's determination of its oil and natural gas reserves. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $0.85, $0.82 and $0.91 per Mcfe in 1999, 2000 and 2001, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Unit's unproved properties totaling $14.4 million are excluded from the DD&A calculation. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. The full cost ceiling is based principally on the estimated future discounted net cash flows from Unit's oil and natural gas properties. As discussed in Note 12, such estimates are imprecise. As part of the merger with Questa, the oil and gas properties of Questa were restated from the successful effort method of accounting to the full cost method of accounting used by Unit Corporation.

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

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

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in eighteen oil and natural gas limited partnerships sold privately and publicly. Some of Unit's officers, directors and employees own the interests in most of these partnerships. Unit shares partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse Unit for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

Natural Gas Balancing. Unit uses the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Based upon the 2001 average natural gas price received of $3.89 per Mcf, which excludes the effects of hedging, Unit estimates its balancing position to be approximately $6.4 million on under-produced properties and approximately $6.1 million on over-produced properties. Unit's policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which Unit has imbalances are not material.

Employee and Director Stock Based Compensation. Unit applies APB Opinion 25 in accounting for its stock option plans for its employees and directors. Under this standard, no compensation expense is recognized for grants of options, which include an exercise price equal to or greater than the market price of the stock on the date of grant. Accordingly, based on Unit's grants in 1999, 2000 and 2001 no compensation expense has been recognized. As provided by Financial Accounting Standard No. 123 "Accounting for Stock-Based Compensation," Unit has disclosed the pro forma effects of recording compensation for such option grants based on fair value in Note 6 to the financial statements.

Self Insurance. Unit utilizes self insurance programs for employee group health and worker's compensation. Self insurance costs are accrued based upon the aggregate of estimated liabilities for reported claims and claims incurred but not yet reported. Accrued liabilities include $4,462,000 and $4,583,000 for employer group health insurance and worker's compensation at December 31, 2000 and 2001, respectively. Due to high premium cost, Unit has decided to increase its deductible for general liability claims from $25,000 to $200,000.

Treasury Stock. On August 30, 2001 Unit's Board of Directors authorized the purchase of up to one million shares of Unit's common stock. The timing of stock purchases are made at the discretion of management. At December 31, 2001, 30,000 shares had been repurchased for $296,000.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject Unit to concentrations of credit risk, consist primarily of trade receivables with a variety of national and international oil and natural gas companies. Unit does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large number of customers comprising Unit's customer base. During 2001, one purchaser of Unit's oil and natural gas production accounted for approximately 15 percent of consolidated revenues. At December 31, 2001 accounts receivable from one oil and natural gas purchaser was approximately $2.1 million. In addition, at December 31, 2000 and 2001, Unit had a concentration of cash of $1.7 million and $2.0 million, respectively, with one bank.

Hedging Activities. On January 1, 2001, Unit adopted Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No.'s 137 and 138), "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This statement required all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, Unit is required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change. Unit periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists. Initial adoption of this standard was not material. In the first quarter of 2000, Unit entered into swap transactions in an effort to lock in a portion of its daily production at the higher oil prices which currently existed. These transactions applied to approximately 50 percent of Unit's daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our oil production for August and September of 2000, at prices ranging from $24.42 to $27.01. Unit entered into a collar contract for approximately 25 percent of its daily oil production for the period covering November 1, 2000 to February 28, 2001. The collar had a floor of $26.00 and a ceiling of $33.00 and Unit received $0.86 per barrel for entering into the collar transaction. During 2000, the net effect of these hedging transactions yielded a reduction in Unit's oil revenues of $465,000. During the first quarter of 2001, the net effect of this hedging transaction yielded an increase in oil revenues of $17,200. During the second quarter of 2001, Unit entered into a natural gas collar contract for approximately 36 percent of its June and July 2001 natural gas production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, Unit entered into two natural gas collar contracts for approximately 38 percent of its September thru November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. During 2001 natural gas collar contracts added $2,030,000 to Unit's natural gas revenues. At December 31, 2001, Unit was not holding any natural gas or oil derivative contracts.

Accounting Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Impact of Financial Accounting Pronouncements. On July 20, 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142). For goodwill and intangible assets already in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. Unit expensed $243,000 annually for the amortization of goodwill, and the unamortized balance of goodwill is $5,088,000 at December 31, 2001. FAS 142 is effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Unit does not believe the future impact from the adoption of FAS 142 on our financial position or results of operations will be material.

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

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

NOTE 2 - ACQUISITIONS

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

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

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

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

NOTE 3 - EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share.

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

The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of common shares for the years ended December 31,:

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

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

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

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

At December 31, 2001, Unit has a $100 million bank loan agreement consisting of a revolving credit facility through May 1, 2005 and a term loan thereafter, maturing on May 1, 2008. Borrowings under the loan agreement are limited to a commitment amount. Although, the current value of Unit's assets under the latest loan value computation supported a full $100 million, Unit elected to set the loan commitment at $60 million in order to reduce costs. The loan value under the revolving credit facility is subject to a semi-annual re-determination calculated primarily as the sum of a percentage of the discounted future value of Unit's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of Unit's drilling rig fleet, limited to $20 million, is added to the loan value. Any declines in commodity prices would adversely impact the determination of the loan value.

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

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

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

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

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

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

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

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

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

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

NOTE 5 - INCOME TAXES

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

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

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

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

Realization of the deferred tax asset is dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced.

At December 31, 2001, Unit has an excess statutory depletion carryforward of approximately $7,562,000, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations.

NOTE 6 - EMPLOYEE BENEFIT AND COMPENSATION PLANS

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan ("the Plan") whereby 330,950 shares of common stock were authorized for issuance under the Plan. On May 3, 1995, Unit's shareholders approved and amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the Plan. Under the terms of the Plan, bonuses may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in annual installments subject to certain restrictions. On January 4, 1999, 87,376 shares of common stock were issued for payment of Unit's 1998 year-end bonuses. No shares were issued under the Plan in 2000 and 2001.

Unit also has a Stock Option Plan (the "Option Plan"), which provides for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The Option Plan permits the issuance of qualified or nonqualified stock options. Options granted become exercisable at the rate of 20 percent per year one year after being granted and expire after ten years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant.

Activity pertaining to the Stock Option Plan is as follows:

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at January 1, 1999	769,360	$ 4.19
Exercised	(109,760)	2.76
Cancelled	(2,000)	10.00
Outstanding at December 31, 1999	657,600	4.41
Granted	146,000	16.59
Exercised	(79,700)	4.19
Cancelled	(4,200)	4.94
Outstanding at December 31, 2000	719,700	6.87
Exercised	(177,200)	3.13
Cancelled	(10,400)	10.26
Outstanding at December 31, 2001	532,100	$ 8.09

OUTSTANDING OPTIONS AT DECEMBER 31, 2001

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

EXERCISABLE OPTIONS AT DECEMBER 31, 2001

EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
$2.75 - $ 3.75	189,500	$ 3.27
$7.25 - $16.69	139,800	$ 10.28

Options for 414,200, 407,900 and 329,300 shares were exercisable with weighted average exercise prices of $3.96, $4.24 and $6.25 at December 31, 1999, 2000 and 2001, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Old Plan") and in February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Director's Stock Option Plan (the "Directors' Plan"). Under the Directors' Plan, which replaced the Old Plan, an aggregate of 300,000 shares of Unit's common stock may be issued upon exercise of the stock options. Under the Old Plan, on the first business day following each annual meeting of stockholders of Unit, each person who was then a member of the Board of Directors of Unit and who was not then an employee of Unit or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. Under the Directors' Plan, commencing with the year 2000 annual meeting, the amount granted has been increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. No stock options may be exercised during the first six months of its term except in case of death and no stock options are exercisable after ten years from the date of grant.

Activity pertaining to the Directors' Plan is as follows:

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at January 1, 1999	72,500	$ 5.74
Granted	12,500	6.90
Exercised	(5,000)	5.13
Cancelled	(2,500)	8.94
Outstanding at December 31, 1999	77,500	5.86
Granted	17,500	12.19
Outstanding at December 31, 2000	95,000	7.03
Granted	17,500	17.54
Exercised	(37,000)	6.80
Outstanding at December 31, 2001	75,500	$ 9.58

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

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

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

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 1999, 2000 and 2001 was 0.55, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 6.70, 5.26 and 5.41 percent in 1999, 2000 and 2001, respectively. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees. The aggregate fair value of options granted during 2000 under the Stock Option Plan were $1,470,000. No options were issued under the Stock Option Plan in 1999 and 2001. Under the Non-Employee Director's Stock Option Plan the aggregate fair value of options granted during 1999, 2000 and 2001 were $58,000, $99,000 and $201,000, respectively.

Under Unit's 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. Unit may match each employee's contribution, up to a specified maximum, in full or on a partial basis. The Company made discretionary contributions under the plan of 105,819, 58,353 and 35,016 shares of common stock and recognized expense of $464,000, $595,000 and $1,082,000 in 1999, 2000 and 2001, respectively.

Unit provides a salary deferral plan ("Deferral Plan") which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy Unit's obligation under the Deferral Plan at December 31, 1999, 2000 and 2001 totaled $1,165,000, $1,536,000 and $1,277,000, respectively. Unit recognizes payroll expense and records a liability at the time of deferral.

Effective January 1, 1997, Unit adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with Unit is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 week's salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against Unit in exchange for receiving the separation benefits. On October 28, 1997, Unit adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Unit recognized expense of $502,000, $558,000 and $589,000 in 1999, 2000 and 2001, respectively, for benefits associated with anticipated payments from both separation plans.

We have entered into key employee change of control contracts with five of our executive officers. These severance contracts have an initial three-year term that is automatically extended for one year upon each anniversary, unless a notice not to extend is given by us. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated by the company (other than for cause, death or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and upon certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 7 - TRANSACTIONS WITH RELATED PARTIES

Unit formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2001, with a subsidiary of Unit serving as General Partner. Questa Oil and Gas Co. formed five private limited partnerships from 1981 to 1993. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with Unit in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with Unit and Questa, respectively, in most drilling operations and most producing property acquisitions commenced by Unit or Questa for their own account during the period from the formation of the Partnerships through December 31 of each year. Unit repurchased the limited partner's interest in three of five Questa partnerships in the fourth quarter of 2000 and one of the Questa partnerships in the first quarter of 2001 and the four partnerships were dissolved.

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

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

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

A subsidiary of Unit paid the Partnerships, for which Unit or a subsidiary is the general partner, $9,000, $6,000 and $3,000 during the years ended December 31, 1999, 2000 and 2001, respectively, for purchases of natural gas production.

NOTE 8 - SHAREHOLDER RIGHTS PLAN

Unit maintains a Shareholder Rights Plan (the "Plan") designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Unit without offering fair value to all shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from Unit one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by Unit or to purchase from an acquiring Company certain shares of its common stock or the surviving company's common stock at 50 percent of its value.

The rights become exercisable 10 days after Unit learns that an acquiring person (as defined in the Plan) has acquired 15 percent or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15 percent or more of such shares. Unit can redeem the rights for $0.01 per right at any date prior to the earlier of (i) the close of business on the tenth day following the time Unit learns that a person has become an acquiring person or (ii) May 19, 2005 (the "Expiration Date"). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Unit leases office space under the terms of operating leases expiring through January 31, 2007. Future minimum rental payments under the terms of the leases are approximately $654,000, $648,000, $648,000, $193,000 and $151,000 in 2002, 2003, 2004, 2005 and 2006, respectively. Total rent expense incurred by the Company was $422,000, $535,000 and $582,000 in 1999, 2000 and 2001, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, upon the election of a limited partner, that Unit repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20 percent of the units outstanding. Unit made repurchases of $10,000 and $14,000 in 1999 and 2000, respectively, for such limited partners' interests. No repurchases were made in 2001. Subsequent to the merger, in 2000, Unit also paid $17,000 for additional interest in two of the Questa limited partnerships and $1,980,000 for all the remaining interest in three other Questa partnerships. In 2001, Unit paid $15,000 for interests in two of the Questa limited partnerships and subsequently dissolved one of the Questa partnerships.

Unit is a party to various legal proceedings arising in the ordinary course of its business none of which, in management's opinion, will result in judgments which would have a material adverse effect on Unit's financial position, operating results or cash flows.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

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

The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 1). Management evaluates the performance of Unit's operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Unit has natural gas production in Canada, which is not significant.

		1999		2000		2001
(In thousands)						
Revenues:						
Contract drilling	$	55,479	$	108,075	$	167,042
Oil and natural gas		46,225		92,016		90,237
Other		648		1,173		1,900
Total revenues	$	102,352	$	201,264	$	259,179
Operating Income *(1)*:						
Contract drilling	$	907	$	12,025	$	62,148
Oil and natural gas		14,027		53,770		45,925
Total operating income		14,934		65,795		108,073
General and administrative expense		(5,750)		(6,560)		(8,476)
Interest expense		(5,268)		(5,136)		(2,818)
Other income (expense) - net		648		1,173		1,900
Income before income taxes	$	4,564	$	55,272	$	98,679
Identifiable Assets *(2)*:						
Contract drilling	$	125,853	$	141,324	$	183,471
Oil and natural gas		164,252		198,251		220,476
Total identifiable assets		290,105		339,575		403,947
Corporate assets		5,462		6,713		13,306
Total assets	$	295,567	$	346,288	$	417,253
Capital Expenditures:						
Contract drilling	$	55,656	$	22,045	$	51,280
Oil and natural gas		21,532		39,884		56,933
Other		744		3,324		539
Total capital expenditures	$	77,932	$	65,253	$	108,752
Depreciation, Depletion, Amortization and Impairment:						
Contract drilling	$	6,851	$	11,999	$	13,888
Oil and natural gas		17,114		18,492		22,116
Other		320		455		638
Total depreciation, depletion, amortization and impairment	$	24,285	$	30,946	$	36,642

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

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

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

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

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

(2) Due to the effect of price changes of Unit's stock, diluted earnings per share for the year's four quarters, which includes the effect of potential dilutive common shares calculated during each quarter, does not equal the annual diluted earnings per share, which includes the effect of such potential dilutive common shares calculated for the entire year.

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

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

NOTE 12 - OIL AND NATURAL GAS INFORMATION

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

(In thousands)	USA	CANADA	TOTAL
1999:			
Capitalized costs:			
Proved properties	$ 301,725	$ 508	$ 302,233
Unproved properties	9,654	382	10,036
	311,379	890	312,269
Accumulated depreciation, depletion, amortization and impairment	(158,147)	(420)	(158,567)
Net capitalized costs	$ 153,232	$ 470	$ 153,702
Cost incurred:			
Unproved properties	$ 1,724	$ 101	$ 1,825
Producing properties	3,733	28	3,761
Exploration	2,037	—	2,037
Development	13,909	—	13,909
Total costs incurred	$ 21,403	$ 129	$ 21,532
2000:			
Capitalized costs:			
Proved properties	$ 338,159	$ 553	$ 338,712
Unproved properties	10,795	200	10,995
	348,954	753	349,707
Accumulated depreciation, depletion, amortization and impairment	(176,515)	(435)	(176,950)
Net capitalized costs	$ 172,439	$ 318	$ 172,757
Cost incurred:			
Unproved properties	$ 5,522	$ 16	$ 5,538
Producing properties	3,752	45	3,797
Exploration	2,409	—	2,409
Development	28,140	—	28,140
Total costs incurred	$ 39,823	$ 61	$ 39,884
2001:			
Capitalized costs:			
Proved properties	$ 391,216	$ 888	$ 392,104
Unproved properties	14,207	180	14,387
	405,423	1,068	406,491
Accumulated depreciation, depletion, amortization and impairment	(196,270)	(475)	(196,745)
Net capitalized costs	$ 209,153	$ 593	$ 209,746
Cost incurred:			
Unproved properties	$ 7,503	$ 21	$ 7,524
Producing properties	1,419	—	1,419
Exploration	9,336	—	9,336
Development	38,359	295	38,654
Total costs incurred	$ 56,617	$ 316	$ 56,933

The results of operations for producing activites are provided below.

(In thousands)	USA	CANADA	TOTAL
1999:			
Revenues	$ 42,999	$ 63	$ 43,062
Production costs	(11,739)	(20)	(11,759)
Depreciation, depletion, amortization and impairment	(16,848)	(8)	(16,856)
	14,412	35	14,447
Income tax expense	(4,387)	(14)	(4,401)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 10,025	$ 21	$ 10,046
2000:			
Revenues	$ 88,461	$ 110	$ 88,571
Production costs	(16,457)	(19)	(16,476)
Depreciation, depletion and amortization	(18,258)	(15)	(18,273)
	53,746	76	53,822
Income tax expense	(20,350)	(30)	(20,380)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 33,396	$ 46	$ 33,442
2001:			
Revenues	**$ 86,810**	**$ 190**	**$ 87,000**
Production costs	**(18,636)**	**(23)**	**(18,659)**
Depreciation, depletion and amortization	**(19,756)**	**(40)**	**(19,796)**
	48,418	**127**	**48,545**
Income tax expense	**(17,621)**	**(40)**	**(17,661)**
Results of operations for producing activities (excluding corporate overhead and financing costs)	**$ 30,797**	**$ 87**	**$ 30,884**

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

	USA		CANADA		TOTAL	
	OIL BBLS	NATURAL GAS MCF	OIL BBLS	NATURAL GAS MCF	OIL BBLS	NATURAL GAS MCF
(In thousands)						
1999:						
Proved developed and undeveloped reserves:						
Beginning of year	3,629	175,884	—	523	3,629	176,407
Revision of previous estimates	1,046	1,308	—	81	1,046	1,389
Extensions, discoveries and other additions	157	19,398	—	—	157	19,398
Purchases of minerals in place	139	7,922	—	—	139	7,922
Sales of minerals in place	(20)	(340)	—	—	(20)	(340)
Production	(424)	(17,402)	—	(35)	(424)	(17,437)
End of year	4,527	186,770	—	569	4,527	187,339
Proved developed reserves:						
Beginning of year	2,749	134,504	—	421	2,749	134,925
End of year	3,583	144,992	—	467	3,583	145,459
2000:						
Proved developed and undeveloped reserves:						
Beginning of year	4,527	186,770	—	569	4,527	187,339
Revision of previous estimates	(45)	6,385	—	(82)	(45)	6,303
Extensions, discoveries and other additions	286	37,896	—	—	286	37,896
Purchases of minerals in place	229	4,893	—	—	229	4,893
Sales of minerals in place	(326)	(1,509)	—	—	(326)	(1,509)
Production	(488)	(19,239)	—	(46)	(488)	(19,285)
End of year	4,183	215,196	—	441	4,183	215,637
Proved developed reserves:						
Beginning of year	3,583	144,992	—	467	3,583	145,459
End of year	3,222	162,718	—	389	3,222	163,107
2001:						
Proved developed and undeveloped reserves:						
Beginning of year	4,183	215,196	—	441	4,183	215,637
Revision of previous estimates	(214)	(24,253)	—	(7)	(214)	(24,260)
Extensions, discoveries and other additions	861	54,521	—	—	861	54,521
Purchases of minerals in place	8	1,246	—	—	8	1,246
Sales of minerals in place	(3)	(26)	—	—	(3)	(26)
Production	(492)	(18,819)	—	(45)	(492)	(18,864)
End of year	4,343	227,865	—	389	4,343	228,254
Proved developed reserves:						
Beginning of year	3,222	162,718	—	389	3,222	163,107
End of year	2,753	150,419	—	338	2,753	150,757

Oil and natural gas reserves cannot be measured exactly. Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures. Unit utilizes Ryder Scott Company, independent petroleum consultants, to review our reserves as prepared by our reservoir engineers.

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

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

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

(In thousands)	USA	CANADA	TOTAL
1999:			
Future cash flows	$ 557,915	$ 1,281	$ 559,196
Future production and development costs	(213,929)	(344)	(214,273)
Future income tax expenses	(81,039)	(175)	(81,214)
Future net cash flows	262,947	762	263,709
10% annual discount for estimated timing of cash flows	(95,722)	(285)	(96,007)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 167,225	$ 477	$ 167,702
2000:			
Future cash flows	$ 2,260,796	$ 4,155	$ 2,264,951
Future production and development costs	(484,900)	(433)	(485,333)
Future income tax expenses	(574,099)	(1,099)	(575,198)
Future net cash flows	1,201,797	2,623	1,204,420
10% annual discount for estimated timing of cash flows	(527,210)	(1,184)	(528,394)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 674,587	$ 1,439	$ 676,026
2001:			
Future cash flows	$ 676,051	$ 975	$ 677,026
Future production and development costs	(279,499)	(341)	(279,840)
Future income tax expenses	(94,037)	(134)	(94,171)
Future net cash flows	302,515	500	303,015
10% annual discount for estimated timing of cash flows	(125,238)	(194)	(125,432)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 177,277	$ 306	$ 177,583

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

(In thousands)	USA	CANADA	TOTAL
1999:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (31,260)	$ (44)	$ (31,304)
Net changes in prices and production costs	42,319	23	42,342
Revisions in quantity estimates and changes in production timing	987	44	1,031
Extensions, discoveries and improved recovery, less related costs	24,035	—	24,035
Purchases of minerals in place	8,612	—	8,612
Sales of minerals in place	(320)	—	(320)
Accretion of discount	8,096	44	8,140
Net change in income taxes	(18,355)	7	(18,348)
Other - net	1,888	4	1,892
Net change	36,002	78	36,080
Beginning of year	131,223	399	131,622
End of year	$ 167,225	$ 477	$ 167,702
2000:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (72,005)	$ (91)	$ (72,096)
Net changes in prices and production costs	647,313	1,854	649,167
Revisions in quantity estimates and changes in production timing	44,991	(324)	44,667
Extensions, discoveries and improved recovery, less related costs	184,624	—	184,624
Purchases of minerals in place	23,144	—	23,144
Sales of minerals in place	(3,469)	—	(3,469)
Accretion of discount	19,881	51	19,932
Net change in income taxes	(293,357)	(581)	(293,938)
Other - net	(43,760)	53	(43,707)
Net change	507,362	962	508,324
Beginning of year	167,225	477	167,702
End of year	$ 674,587	$ 1,439	$ 676,026
2001:			
Sales and transfers of oil and natural gas produced, net of production costs	**$ (68,174)**	**$ (167)**	**$ (68,341)**
Net changes in prices and production costs	**(768,295)**	**(1,600)**	**(769,895)**
Revisions in quantity estimates and changes in production timing	**(32,705)**	**13**	**(32,692)**
Extensions, discoveries and improved recovery, less related costs	**54,127**	—	**54,127**
Purchases of minerals in place	**1,217**	—	**1,217**
Sales of minerals in place	**(220)**	—	**(220)**
Accretion of discount	**99,953**	**205**	**100,158**
Net change in income taxes	**271,421**	**524**	**271,945**
Other - net	**(54,634)**	**(108)**	**(54,742)**
Net change	**(497,310)**	**(1,133)**	**(498,443)**
Beginning of year	**674,587**	**1,439**	**676,026**
End of year	**$ 177,277**	**$ 306**	**$ 177,583**

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

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

Future cash flows are computed by applying year-end spot prices of oil ($17.71) and natural gas ($2.51) relating to proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

REPORT OF INDEPENDENT ACCOUNTANTS

THE SHAREHOLDERS AND BOARD OF DIRECTORS
Unit Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in shareholders' equity and cash flows present fairly in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2000 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these financial statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 20, 2002

Corporate Headquarters

Unit Corporation
1000 Kensington Tower
7130 South Lewis
Tulsa, Oklahoma 74136
918-493-7700

World Wide Web Adress

http://www.unitcorp.com

Transfer Agent and Registrar

Communications concerning the transfer of shares, lost certificates, and changes of address should be directed to:
Transfer Agent/Registrar
Mellon Investor Services, LLC
85 Challenger Road
Ridgefield, NJ 07660

You may reach them by telephone at 800-851-9677 or via the Internet at http://www.melloninvestor.com.

Stock Listing

Our common stock trades on the New York Stock Exchange under the symbol: "UNT." During 2001, 43.8 million shares of our stock were traded on the NYSE, compared with 34.9 million shares in 2000. Approximately 36.0 million shares were outstanding at the end of 2001.

Shareholder Profile

We had 2,001 shareholders of record at year-end 2001.

Annual Meeting

Our annual meeting of stockholders will be held at 11:00 a.m. on May 1, 2002 in the Tulsa Room, formerly known as the Green Room, at the Bank of Oklahoma Tower, 9th floor, in Tulsa Oklahoma.

Investor Relations

The Form 10-K report is available in April. The Form 10-Q reports are available in May, August and November. Copies of the Forms 10-K, 10-Q and Annual Report, filed with the Securities and Exchange Commission, are available without charge upon written request to Linda Swanson, Investor Relations Department, 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136.
Telephone: 918-493-7700

Independent Accountants

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

Forward Looking Statements

This report contains forward-looking statements within the meaning of the Securities Litigation Reform Act that involve risks and uncertainties, including price volatility, development, operational, implementation and opportunity risks and other factors described from time to time in our publicly available SEC reports which could cause actual results to differ materially from those expected. We urge you to read these documents, including our 10-K, all of which can be obtained from the SEC's website at www.sec.gov.

The terms Corporation, Company, Unit, our, we and its, as used in this report, sometimes refer not only to Unit Corporation but also to one or more of its subsidiaries or predecessor companies. The shorter terms are used merely for convenience and simplicity.

Definitions and Abbreviations

Mcf	Thousand cubic feet of natural gas
MMcf	Million cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent of natural gas
MMcfe	Million cubic feet equivalent of natural gas
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet equivalent of natural gas
Bbls	Barrels of oil
MBbls	Thousand barrels of oil

UNIT CORPORATION

1000 Kensington Tower
7130 South Lewis Avenue
Tulsa, Oklahoma 74136
918-493-7700
www.unitcorp.com