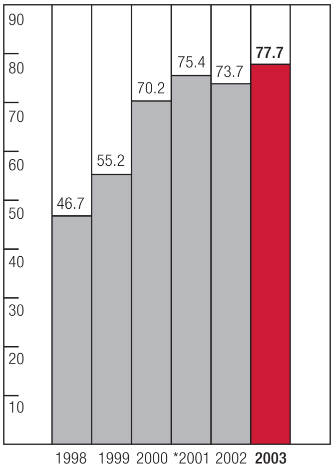
GOODRICH
PETROLEUM CORPORATION

ANNUAL REPORT 2003

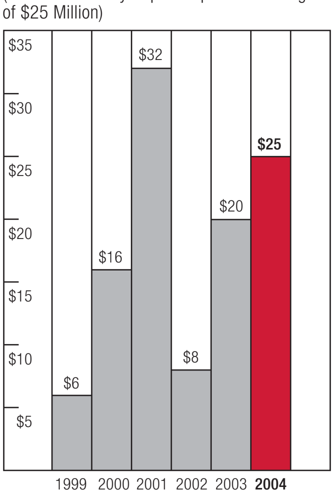
Proved Reserves
BCFE



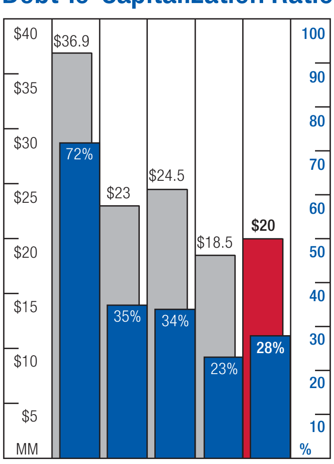
* Proforma includes 30% Burrwood/West Delta Sale March 12, 2002

Capital Expenditures
in millions

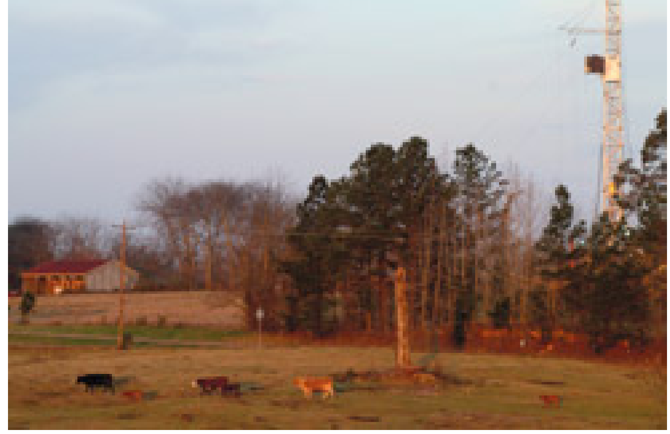
(2004 Preliminary Capital Expenditure Budget of $25 Million)



Outstanding Debt and Net Debt-To-Capitalization Ratio



We believe the results of 2003 have us well-positioned to achieve our goals for 2004.



Dear Fellow Shareholder,

Our singular focus and objective is to create and enhance the value of our company for the benefit of its shareholders. Our strategy for achieving this objective is to build the underlying value of our oil and natural gas reserves and to grow production volumes on a per share basis. We have and continue to do this by investing in quality projects designed to add net present value, at an attractive rate of return, for each dollar we invest.

At the core of our strategy is the expansion of our base of reserves and production, which we believe will result in increased cash flow and improving financial performance. In order to expand our base we have adopted a balanced approach, which includes oil and gas reserve acquisitions, exploitation, development and exploration activities. Through this balanced approach, we expect to further expand our oil and natural gas reserve base and thereby, allow us to pursue additional high-impact opportunities. In the current commodity price environment, the number of new opportunities to invest in production and reserve growth projects is even further enhanced.

Results

Significant results were achieved during 2003 on a number of fronts. During the year we drilled twelve wells, of which nine were successful, resulting in a seventy-five percent (75%) rate of success on wells drilled. Through our drilling activities, we added approximately 11.3 billion cubic feet equivalent ("BCFE") of reserves before revisions, which resulted in a 2003 net reserve replacement of approximately one hundred and eighty-nine percent (189%). These reserves were added from capital expenditures of approximately $20 million, which resulted in 2003 finding and development costs of $1.76 per Mcfe.

Our 2003 development program also allowed us to achieve a twenty-one percent (21%) growth in production when compared with 2002. The production volume growth achieved

In the current commodity price environment, the number of new opportunities to invest in production and reserve growth projects is even further enhanced.

during 2003 resulted in record annual revenue for Goodrich Petroleum of approximately $33 million. Our record revenue provided increased cash flow from operations during 2003 of approximately $18 million, which in turn contributed to our net income of $3.7 million and net income applicable to common stock, after preferred stock dividends, of approximately $3.1 million.

Our 2003 net income, and that of previous years, was negatively impacted by a systematic error discovered in the method used to calculate the per unit amounts of depreciation, depletion and amortization of production. The error was detected during the 2003 audit and has been corrected for past and future calculations. All of the required recalculations were non-cash items, which had no impact on our cash flow from operations or our working capital and resulted in a corresponding reduction in the amount of future costs required to be amortized and depreciated.

The revenue, reserve and cash flow growth was achieved with a very modest increase in long term debt of only $1.5 million, which ended the year at $20 million. Our year end reserves, prepared by a third party engineering firm, were approximately 78.0 BCFE. Our year end reserves resulted in a pre-tax net present value, discounted at ten percent (10%) and utilizing SEC reserve pricing of $6.42 per Mcf of natural gas and $31.75 per barrel of oil, of approximately $215 million. This enhanced reserve base and increased present value gives us a strengthened base upon which to further grow reserves and results in a current net asset value of proved reserves, after deducting liabilities, of approximately $9.00 per share on a fully diluted basis.

Our results in 2003 also included improved efficiencies from our on-going efforts to maintain

and reduce costs while expanding production volumes. Importantly, during 2003 and in early 2004, we expanded our inventory of development opportunities, including our expansion of acreage and opportunities in North Louisiana and East Texas. Our efforts in this area, the Cotton Valley Trend in particular, resulted in our acquiring working interests in approximately 33,000 gross acres during the past year. Today, our inventory is clearly the richest it has been in our corporate history.

Looking Forward

As we look forward, we are encouraged by the current market conditions and outlook for future oil and natural gas prices. At the same time, in order to enhance the economics of future projects and to mitigate future volatility of oil and gas commodity prices, our Hedging Committee is actively working to capture as much of the current prices for future production as is prudent. Our current hedge position has a significant portion of our current crude oil production hedged through calendar year 2004 and natural gas hedged through calendar year 2004, as well as the first quarter of 2005. The prices hedged are significantly above our internal threshold prices used in the economic analysis of our 2004 drilling and development projects. The increase in cash flow, depth of inventory and excellent commodity price expectations have resulted in our increasing our preliminary capital expenditure budget for 2004 by twenty-five percent (25%) to $25 million when compared to 2003.

The 2004 capital expenditure budget is designed to accelerate development of our expanded inventory, including the increased mix of opportunities from our acreage in the Cotton Valley Trend, where we have the potential for a large number of low risk locations which also gives us increased exposure to primarily natural gas reserves. Our 2004 plans call for at least six

Today, our inventory is clearly the richest it has been in our corporate history.

wells to be drilled in the Cotton Valley Trend, which should increase significantly with anticipated drilling and production results on our existing acreage. At the same time, we continue to focus on the transition zone of South Louisiana and further development of our core properties. In addition to the further development of these properties in 2004, we have entered into agreements and committed to shoot two (2) new 3-D seismic surveys in South Louisiana totaling approximately sixty (60) square miles over two (2) separate mature oil and natural gas fields. We currently expect both surveys will be completed, the 3-D to be processed and evaluation of the data and exploration opportunities to begin by the third quarter of 2004.

We are both excited and optimistic about our potential for further growth in 2004. During the year, we will again be aggressively pursuing opportunities to further expand our reserves, production, cash flow and project inventory on a cost effective basis. We believe the results of 2003 have us well-positioned to achieve our goals for 2004. The early results in 2004 are very encouraging, with two new discoveries made and announced on our Dempsey and Norton Prospects in the Burrwood and West Delta 83 area of Plaquemines Parish Louisiana.

As always, we want to thank all our employees for their hard work and dedication and appreciate their contribution to the success we have achieved. We also thank our fellow shareholders for their continued commitment, loyalty and support of our goals, efforts and objectives.

Sincerely,

Patrick E. Malloy III
Chairman of the Board

Walter G. Goodrich
Vice-Chairman & CEO

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 (*Fee Required*)

For Fiscal Year Ended December 31, 2003
Commission file number 1-7940

GOODRICH PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State of incorporation)	**(I.R.S. Employer Identification No.)**
808 Travis St., Suite 1320	
Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code is (713) 780-9494

Title of each class	Name of each exchange on which registered
Securities registered pursuant to Section 12(b) of the Act:	
Common Stock, $0.20 par value	New York Stock Exchange
Securities registered pursuant to Section 12(g) of the Act:	
Series A Preferred Stock, $1.00 par value	NASDAQ Small Cap

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

At April 9, 2004, there were 18,506,354 shares of Goodrich Petroleum Corporation common stock outstanding. The aggregate market value of shares of common stock held by non-affiliates of the registrant as of April 9, 2004, was approximately $45,337,000 based on a closing price of $6.75 per share on the New York Stock Exchange on such date.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

At June 30, 2003, the aggregate market value of Goodrich Petroleum Corporation common stock held by non-affiliates was $25,490,100.

Documents Incorporated By Reference

Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 2003, are incorporated by reference into Part III of this Form 10-K.

GOODRICH PETROLEUM CORPORATION

FORM 10-K

December 31, 2003

INDEX

PART I

Items 1 and 2. *Business and Properties*.

General

Goodrich Petroleum Corporation and subsidiaries ("Goodrich" or the "Company") is an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the transition zone of south Louisiana and in East Texas, north Louisiana and the Gulf Coast of Texas. The Company owns working interests in 85 active oil and gas wells located in 22 fields in four states. At December 31, 2003, Goodrich had estimated proved reserves of approximately 7.8 million barrels of oil and condensate and 30.9 billion cubic feet ("Bcf") of natural gas, or an aggregate of 77.7 Bcf equivalent ("Bcfe") with a pre-tax present value of future net revenues, discounted at 10%, of $214.6 million and an after-tax present value of future net revenues of $163.97 million.

The Company's principal executive offices are located at 808 Travis Street, Suite 1320, Houston, Texas 77002. The Company also has an office in Shreveport, Louisiana. At April 9, 2004, the Company had 37 employees.

Company Background and Business Strategy

Goodrich resulted from a business combination on August 15, 1995 between La/Cal Energy Partners ("La/Cal") and Patrick Petroleum Company and subsidiaries ("Patrick").

The Company's business strategy is to provide long term growth in net asset value per share, through the growth and expansion of its oil and gas reserves and production. The Company focuses on adding reserve value through the careful evaluation and aggressive pursuit of oil and gas drilling and acquisition opportunities. Economic analyses are prepared on each drilling and acquisition opportunity with criteria of adding net present value for every dollar invested. In addition, the Company implements an active hedging program designed to partially reduce commodity price risks in an effort to realize the desired economic returns.

Several of the key elements of Goodrich's business strategy are the following:

- *Exploit and Develop Existing Property Base*. The Company seeks to maximize the value of its existing assets by developing and exploiting its properties with the highest production and reserve growth potential. Goodrich performs continuous field studies of its existing properties using advanced technologies. The Company seeks to minimize costs by controlling operations to the extent possible.
- *Pursue Strategic Acquisitions*. To leverage its extensive regional knowledge base, the Company seeks to acquire leasehold acreage and producing or non-producing properties in areas, such as south Louisiana and East Texas, which are in mature fields with complex geology that have multiple reservoirs and existing infrastructure.
- *Selectively Grow Through Exploration*. The Company conducts an active exploration program that is designed to complement its lower risk exploitation and development efforts with moderate risk exploration projects offering greater reserve potential. Goodrich utilizes 3-D seismic data and other technical applications, as appropriate, to manage its exploration risks. The Company also attempts to reduce its risks through the judicious use of cost sharing arrangements with outside drilling partners.
- *Rationalize Property Portfolio*. The Company continually strives to rationalize its portfolio of properties by selling marginal properties in an effort to redeploy capital to exploitation, development and exploration projects which offer a potentially higher overall return.

Oil and Gas Operations and Properties

The following is a summary description of the Company's oil and gas properties.

Louisiana

The majority of the Company's proved oil and natural gas reserves are in the transition zone of the south Louisiana producing region. This region refers to the geographic area that covers the onshore and in-land waters of south Louisiana lying in the southern half of Louisiana, which is one of the most prolific oil and natural gas producing sedimentary basins. The region generally contains sedimentary sandstones, which are of high qualities of porosity and permeabilities. There is a myriad of types of reservoir traps found in the region. These traps are generally formed by faulting, folding and subsurface salt movement, or a combination of one or more of these.

The formations found in the southern Louisiana producing region range in depth from 1,000 feet to 20,000 feet below the surface. These formations range from the Sparta and Frio formations in the northern part of the region to Miocene and Pleistocene in the southern part of the region. The Company's production comes predominately from Miocene and Frio age formations.

Burrwood and West Delta 83 Fields. The Burrwood and West Delta 83 fields, located in Plaquemines Parish, Louisiana, were discovered in 1955 by Chevron. The fields lie upthrown to a large down-to-the southeast growth fault system with the structure striking northeast-southwest and dipping northwestward in a counter-regional direction. The fields have collectively produced over 49 million barrels of oil and 144 Bcf of natural gas. The productive sands are Miocene and Pliocene age sands ranging in depth from 6,300 feet to approximately 11,700 feet. There are currently 21 active producing wells in the fields.

Goodrich acquired a 95% working interest in approximately 8,600 acres of the Burrwood and West Delta 83 fields through an acquisition that closed on March 2, 2000 with an effective date of January 1, 2000. On March 12, 2002, the Company monetized a portion of the value created in the two fields by selling a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, in such fields for $12 million to Malloy Energy Company, LLC ("MEC") led by Patrick E. Malloy, III and participated in by Sheldon Appel, who was a member of the Company's Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of the Company's Board of Directors (Mr. Malloy is currently Chairman of the Company's Board of Directors and Mr. Appel retired from the Board of Directors in February 2004). For a further discussion of this transaction, see Note C of the Company's consolidated financial statements in Item 8.

Lafitte Field. The Lafitte field is located in Jefferson Parish, Louisiana and was discovered in 1935 by Texaco. The Lafitte field is a large, north-south elongated salt dome anticline feature. There are currently more than thirty (30) defined productive sands, which have collectively produced in excess of 264 million barrels of oil and 319 Bcf of natural gas. The productive sands are Miocene and Pliocene age sands ranging in depth from 3,000 feet to approximately 12,000 feet. There are currently 26 active producing wells in the field. In September 1999, the Company acquired a non-operated working interest of approximately 49% in the Lafitte field with respect to the field's leases, surface facilities and equipment and a non-operated working interest of approximately 45% in the active producing wells. In November 1999, the Company acquired additional interests, resulting in a field-wide non-operated working interest of approximately 49%.

Second Bayou Field. The Second Bayou field is located in Cameron Parish, Louisiana and was discovered in 1955 by the Sun Texas Company. Goodrich is the operator of eight producing wells, five of which are dually completed, and has an average working interest of approximately 31% in 1,395 gross acres. To date, the field has produced over 425 Bcf of natural gas and 3.6 million barrels of oil from multiple Miocene aged sands ranging from 4,000 to 15,200 feet.

Pecan Lake Field. The Pecan Lake field was discovered in 1944 by the Superior Oil Company. Geologically, the field is comprised of a relatively low relief, four-way closure and multiple stacked pay sands. The Pecan Lake field comprises approximately 870 gross leased acres in Cameron Parish, Louisiana. The field has produced from over 15 Miocene aged sands ranging in depths from 7,500 to 11,800 feet, which have been predominately gas and gas condensate reservoirs. These sand reservoirs are characterized by generally widespread development and strong waterdrive production mechanisms. The field has produced in excess of 354 Bcf of gas and 798,000 barrels of condensate. All of the field production to date has come from normal pressured reservoirs. The Company is the operator of two producing wells with working interests ranging from approximately 43% to 47%.

Isle St. Jean Charles Field. Isle St. Jean Charles field is located in Terrebonne Parish, Louisiana. The field is a northwest extension of the Bayou Jean LaCroix field located in the southeastern area of the Parish. These fields are trapped on a four-way closure, downthrown on a major east-west trending down to the south fault.

Production is from multiple Miocene-aged sands, which are normally pressured and range in depth from 9,000 feet to 13,000 feet. The field was developed primarily in the 1950's by Exxon and reservoirs have exhibited both depletion and water drive mechanisms. To date, this field has produced in excess of 57 Bcf of gas and 6.61 million barrels of oil and condensate. Goodrich owns an approximate 34% working interest in its leasehold of approximately 425 acres.

Bethany-Longstreet. The Bethany-Longstreet field is located in Caddo and DeSoto Parishes in northwestern Louisiana and was discovered by several independent oil and gas companies in the late 1940's and early 1950's. The majority of the production in the field has come from the "Crane" zone of the Pettit formation which was developed primarily in the 1950's and 1960's. In July 2003, the Company obtained, via farmout, the right to drill and earn all rights, excluding exploration rights to the Crane zone of the Pettit formation, in approximately 18,000 acres in the field. The Company, will retain continuous drilling rights to the entire block so long as it drills at least one well every 120 days. For each productive well drilled under the agreement, the Company will earn an assignment of 160 acres. The Company has begun exploration and development drilling activities in the field and completed three successful wells as of December 31, 2003. The Company anticipates drilling additional wells on the block in 2004 and expects that its working interests in the wells will range between 50% and 70%.

Plumb Bob. The Plumb Bob field is located in St. Martin Parish in southern Louisiana and was originally discovered by Texaco in 1939. Apache acquired the field from Texaco in a large divesture package in 1995 and did not drill any additional wells in the field prior to the time it was abandoned in 1997. In September 2003, the Company reached an agreement with a subsequent owner to obtain certain rights in the field. The rights include oil and gas leases covering approximately 450 acres, 3-D seismic permits with oil and gas lease options covering approximately 17,000 acres, seven existing shut-in wellbores, where the Company has identified recompletion projects, and the rights to acquire related production facilities and pipelines upon establishment of production. The Company's plans include a workover and well reactivation program, the shooting of a 32 square mile 3-D seismic survey and post 3-D exploitation and development drilling activities. The Company has begun workover drilling activities in the field and had restored production capability in three wells as of December 31, 2003. The 3-D seismic shoot began during the fourth quarter of 2003 and is expected to be completed in the second quarter of 2004. Based on its expected 70% working interest, the Company has budgeted net capital expenditures in the Plumb Bob field of up to $3.7 million in the full year 2004.

Other. In July 2003, the Company acquired an 18% working interest in two non-operated exploratory prospects encompassing a total of approximately 1,100 acres adjacent to the Bayou Choupique field in Calcasieu Parish, Louisiana. Exploratory wells were drilled on each of the prospects in the third quarter of 2003 with one such well being successful and the other well being unsuccessful. Oil and gas production from the successful well commenced in November 2003. The Company anticipates that the operator will propose the drilling of an offset well to the successful well in the second quarter of 2004, at which time the Company will decide whether to make an election to participate.

The Company maintains ownership interests in acreage and wells in several additional fields in Louisiana, including the (i) City of Lake Charles field, located in Calcasieu Parish, (ii) Mosquito Bay field, located in Terrebonne Parish, (iii) Ada field, located in Bienville Parish, and (iv) Lake Raccourci field, located in Terrebonne Parish.

Texas

Goodrich presently has production operations in the eastern, western and southern regions of Texas, as more fully described in the three succeeding paragraphs. Additionally as indicated below under "East Texas Drilling Program", the Company is currently undertaking a major new drilling initiative in several additional counties in the eastern portion of Texas.

Sean Andrew Field. The Sean Andrew field in Dawson County, Texas was discovered by the Company in 1994 utilizing the Company's 375 square mile 3-D seismic database in West Texas. The Company is the operator of two wells in the field and holds an approximate 37.5% working interest.

Marholl Field. The Marholl field is a Siluro-Devonian (Fussellman) field in Dawson County, Texas, discovered in 1995 through the use of 3-D seismic. The Company operates two wells in the field with an approximate 23% working interest.

Mary Blevins Field. The Mary Blevins field is located in Smith County, Texas. It was a new discovery that is fault separated from Hitts Lake field, which was discovered in 1953 by Sun Oil. Currently, there are four producing wells in the field in which Goodrich serves as operator, having an approximate 48% working interest in 782 gross acres. To date, Hitts Lake has produced over 14 million barrels of oil and Mary Blevins has produced over 551,000 barrels of oil from the Paluxy, which occurs at a depth of approximately 7,300 feet. In the fourth quarter of 2003, the Company commenced a waterflood project in the Mary Blevins field. As a result of the waterflood project, the Company anticipates enhanced production from the Mary Blevins field beginning in the second half of 2004.

East Texas Drilling Program. In the first quarter of 2004, the Company commenced a new drilling initiative which is focused on the Cotton Valley trend in the East Texas Basin in Rusk, Panola and Smith Counties. As of April 9, 2004, the Company had acquired leases totaling approximately 15,000 gross acres and is attempting to acquire additional acreage in the area. The Company presently owns varying working interests ranging from 40% to 100% in the acquired leases and expects to commence a low risk drilling program which will target objectives primarily in the Cotton Valley formation. The Company has preliminarily budgeted total 2004 capital expenditures of approximately $6.5 million under this new drilling initiative. Depending on early results of the drilling program, the Company may elect to increase its level of lease acquisitions and drilling activities in the East Texas Basin.

Other. The Company maintains ownership interests in acreage and wells in several additional fields in Texas including the (i) Ackerly field, located in Dawson and Howard Counties, (ii) Lamesa Farms field, located in Dawson County, and (iii) Midway field, located in San Patricio County.

Australia

In the early 1990's, the Company acquired non-operating interests in two offshore exploration permits in the Carnarvon Basin of Western Australia. In the first quarter of 2003, the Company participated in the drilling of an unsuccessful exploratory well on one of the permits. The Company subsequently relinquished its interests in both exploration permits and has no further plans with respect to any exploration and development operations in Australia.

Oil and Natural Gas Reserves

The following tables set forth summary information with respect to the Company's proved reserves as of December 31, 2003 and 2002, as estimated by the Company by compiling reserve information, substantially all of which was prepared by the engineering firm of Coutret and Associates, Inc.

Category	Net Reserves Oil (Bbls)	Net Reserves Gas (Mcf)	Net Reserves Bcfe(1)	Pre-Tax Present Value of Future Net Revenues (in millions)	After-Tax Present Value of Future Net Revenues (in millions)
December 31, 2003					
Proved Developed	3,600,980	23,429,440	45.04	$131.02	
Proved Undeveloped	4,204,430	7,473,950	32.70	83.60	
Total Proved	7,805,410	30,903,390	77.74	$214.62	$163.97
December 31, 2002					
Proved Developed	2,556,670	15,203,255	30.50	$ 68.06	
Proved Undeveloped	4,884,670	13,866,295	43.20	83.30	
Total Proved	7,441,340	29,069,550	73.70	$151.36	$124.30

(1) Estimated by the Company using a conversion ratio of 1.0 Bbl/6.0 Mcf.

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the pre-tax Present Value of Future Net Revenues amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to the Company's properties.

In accordance with the guidelines of the Securities and Exchange Commission (SEC), the engineers' estimates of future net revenues from the Company's properties and the pre-tax Present Value of Future Net Revenues thereof are made using oil and natural gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The prices as of December 31, 2003, and 2002 used in such estimates averaged $6.42 and $4.35 per Mcf, respectively, of natural gas and $31.75 and $28.80 per Bbl, respectively, of crude oil/condensate.

Productive Wells

The following table sets forth the number of active well bores in which the Company maintains ownership interests as of December 31, 2003:

	Oil		Gas		Net	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Arkansas	—	—	1.00	0.01	1.00	0.01
Louisiana	43.00	22.95	23.00	9.74	66.00	32.69
Michigan	—	—	1.00	0.09	1.00	0.09
Texas	14.00	7.79	3.00	2.33	17.00	10.12
Total Productive Wells	57.00	30.74	28.00	12.17	85.00	42.91

(1) Does not include royalty or overriding royalty interests.
(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. A gross well is a well in which the Company maintains an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by the Company equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, eight had multiple completions.

Acreage

The following table summarizes the Company's gross and net developed and undeveloped natural gas and oil acreage under lease as of December 31, 2003. Acreage in which the Company's interest is limited to a royalty or overriding royalty interest is excluded from the table and does not include acreage acquired in the East Texas Basin (see "Texas – East Texas Drilling Program") acquired subsequent to December 31, 2003.

	Gross	Net
Developed acreage		
Louisiana	12,503	7,316
Michigan	1,920	19
Texas	1,181	440
New Mexico	640	19
Undeveloped acreage		
Louisiana	24,851	15,897
Texas	499	263
Total	41,594	23,954

Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and gas industry, the Company can retain its interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The natural gas and oil leases in which the Company has an interest are for varying primary terms; however, most of the Company's developed lease acreage is beyond the primary term and is held so long as natural gas or oil is produced.

Operator Activities

The Company operates a majority in value of its producing properties, and will generally seek to become the operator of record on properties it drills or acquires in the future.

Drilling Activities

The following table sets forth the drilling activities of the Company for the last three years. (As denoted in the following table, "Gross" wells refers to wells in which a working interest is owned, while a "net" well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.)

	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	8.00	4.68	—	—	4.00	3.39
Non-Productive	1.00	1.00	—	—	—	—
Total	9.00	5.68	—	—	4.00	3.39
Exploratory Wells:						
Productive	1.00	0.18	2.00	1.13	1.00	0.17
Non-Productive	2.00	0.51	—	—	2.00	1.40
Total	3.00	0.69	2.00	1.13	3.00	1.57
Total Wells:						
Productive	9.00	4.86	2.00	1.13	5.00	3.56
Non-Productive	3.00	1.51	—	—	2.00	1.40
Total	12.00	6.37	2.00	1.13	7.00	4.96

Net Production, Unit Prices and Costs

The following table presents certain information with respect to oil, gas and condensate production attributable to the Company's interests in all of its fields, the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2003.

	2003	2002	2001
Net Production:			
Natural gas (Mcf)	3,361,041	2,477,790	3,823,227
Oil (barrels)	484,444	451,564	581,680
Natural gas equivalents (Mcfe) (1)	6,267,705	5,187,174	7,313,307
Average Net Daily Production:			
Natural gas (Mcf)	9,208	6,788	10,475
Oil (Bbls)	1,327	1,237	1,594
Natural gas equivalents (Mcfe) (1)	17,172	14,211	20,039
Average Sales Price Per Unit (2):			
Natural gas (per Mcf)	$ 5.11	$ 3.08	$ 3.97
Oil (per Bbl)	$ 29.49	$ 25.09	$ 24.67
Other Data:			
Lease operating expense (per Mcfe) (2)	$ 0.99	$ 1.50	$ 0.90
Production taxes (per Mcfe)	$ 0.37	$ 0.32	$ 0.26
DD & A (per Mcfe)	$ 1.45	$ 1.40(3)	$ 1.03(3)
Exploration (per Mcfe)	$ 0.36	$ 0.20(3)	$ 0.59(3)

(1) Estimated by the Company using a conversion ratio of 1.0 Bbl/6.0 Mcf.

(2) See "Results of Operations" under Item 7 for discussion of increase in lease operating expense in 2002.

(3) As restated, see "Restatement of 2001 and 2002 Financial Statements" under item 7.

The Company's acquisition strategy for the Gulf Coast Basin calls for the acquisition of mature oil and gas fields with declining production profiles, established production histories and multiple productive sands that have been overlooked and/or starved of capital. Acquisitions of this type generally require significant lease operation, exploration and capital expenditure cash outlays during initial years of ownership. The Company's Lafitte, Burrwood and West Delta 83 fields acquisitions in late 1999 and early 2000, were strategic acquisitions that fit the aforementioned profile, and account for the majority of the unit costs noted above in the periods presented above.

Oil and Gas Marketing and Major Customers

Marketing. Goodrich's natural gas production is sold under spot or market-sensitive contracts to various gas purchasers on short-term contracts. Goodrich's natural gas condensate is sold under short-term rollover agreements based on current market prices. The Company's crude oil production is marketed to several purchasers based on short-term contracts.

Customers. Due to the nature of the industry, the Company sells its oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from these sources as a percent of total revenues for the periods presented were as follows:

	Year Ended December 31,		
	2003	2002	2001
Louis Dreyfus Corporation	47%	—	—
Texon, LP	25%	—	—
Reliant Energy	—	45%	56%
Conoco Phillips	5%	17%	—
Shell Trading	—	17%	—
Genesis Crude Oil, L.P.	—	5%	22%

Competition

The oil and gas industry is highly competitive. Major and independent oil and gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than those of the Company, and staffs and facilities substantially larger than those of the Company. The availability of a ready market for the oil and gas production of the Company will depend in part on the cost and availability of alternative fuels, the level of consumer demand, the extent of domestic production of oil and gas, the extent of importation of foreign oil and gas, the cost of and proximity to pipelines and other transportation facilities, regulations by state and federal authorities and the cost of complying with applicable environmental regulations.

Regulations

The availability of a ready market for any natural gas and oil production depends upon numerous factors beyond the Company's control. These factors include regulation of natural gas and oil production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of natural gas and oil available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which the Company may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount of natural gas and oil produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies as well.

Environmental Matters

The Company's operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the imposition of injunctions to force future compliance.

The Oil Pollution Act of 1990 ("OPA 90") and its implementing regulations impose a variety of requirements related to the prevention of oil spills, and liability for damages resulting from such spills in United States waters. OPA 90 imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operation regulation. If a party fails to report a spill or to cooperate fully in a cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages. For onshore facilities, the total liability limit is $350 million. OPA 90 also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws impose strict, joint and several liability on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These parties include the owner or operator of the site where the release occurred, and those that disposed or arranged for the disposal of hazardous substances found at the site. Responsible parties under CERCLA may be subject to joint and several liability for remediation costs at the site, and may also be liable for natural resource damages. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. See existing environmental matters discussed in Item 3—Legal Proceedings.

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and gas properties, establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from the Company's properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Management believes that the Company is in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its operations or financial condition.

Risk Factors

The Company's Success is Dependent on Oil and Gas Prices. Goodrich's success will depend on the market prices of oil and gas. These market prices tend to fluctuate significantly in response to factors beyond the Company's control. The prices the Company receives for its crude oil production are based on global market conditions. The continued threat of war in the Middle East and actions of OPEC and its maintenance of production constraints, as well as other economic, political, and environmental factors will continue to affect world supply. Natural gas prices fluctuate significantly in response to numerous factors including the U.S. economic environment, North American weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

Average oil and gas prices increased substantially from 2002 to 2003. The year 2002 began with lower commodity prices as a result of the global economic downturn and decreases in demand. During 2002, crude oil prices increased due to a combination of factors including fears of war in Iraq (and the resulting impact on the Middle East), Venezuelan strikes that reduced oil exports, and continued OPEC production discipline. Natural gas prices also increased throughout 2002 as U.S. productive capacity declined and as demand increased in the fourth quarter due, in part, to below–normal temperatures. Commodity prices ended 2002 at their highest levels for the year and continued at a relatively high level throughout 2003. The Company expects that commodity prices will continue to fluctuate significantly in the future.

Changes in commodity prices significantly affect the Company's capital resources, liquidity and expected operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of funds available to reinvest in exploration and development activities. Reductions in oil and gas prices not only reduce revenues and profits, but could also reduce the quantities of reserves that are commercially recoverable. Significant declines in prices could result in non–cash charges to earnings due to impairment. The Company uses derivative financial instruments to hedge its exposure to price risk from changing commodity prices and has hedged a targeted portion of its anticipated production for 2004.

The Company's Operations Require Significant Capital Expenditures. Goodrich must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and gas reserves. Historically, the Company has paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Goodrich's revenues or cash flows could be reduced because of lower oil and gas prices or for other reasons. If Goodrich's revenues or cash flows decrease, the Company may not have the funds available to replace reserves or to maintain production at current levels. If this occurs, the Company's production will decline over time. Other sources of financing may not be available if Goodrich's cash flows from operations are not sufficient to fund its capital expenditure requirements. Where Goodrich is not the majority owner or operator of an oil and gas property, such as the Lafitte field, it may have no control over the timing or amount of capital expenditures associated with the particular property. If Goodrich cannot fund its capital expenditures, its interests in some properties may be reduced or forfeited.

The Company's Oil and Gas Reserve Information Is Estimated. The proved oil and gas reserve information included in this document represents estimates. These estimates are based on reports prepared by consulting reserve engineers and were calculated using oil and gas prices as of December 31, 2003. These prices could change. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Goodrich's actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and gas reserves attributable to Goodrich's properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general.

Oil and Gas Operations Are Subject to Various Economic Risks. The oil and gas operations of Goodrich are subject to the economic risks typically associated with exploration, development and production activities, including the necessity of significant expenditures to locate and acquire properties and to drill exploratory wells. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations or accidents may cause Goodrich's exploration, development and production activities to be unsuccessful. This could result in a total loss of Goodrich's investment in a particular property. If exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs would be charged against earnings as impairments. In addition, the cost and timing of drilling, completing and operating wells is often uncertain.

Drilling Oil and Gas Wells Could Involve Blowouts, Environmental Hazards and Other Risks. The nature of the oil and gas business involves certain operating hazards such as well blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, formations with abnormal pressures, pollution, releases of toxic gas and other environmental hazards and risks. Any of these operating hazards could result in substantial losses to Goodrich. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of Goodrich's properties. Additionally, some of Goodrich's oil and gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. In accordance with customary industry practices, Goodrich maintains insurance against some, but not all, of such risks and losses. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on the financial position and results of operations of Goodrich.

Competition Within the Oil and Gas Industry is Intense. The exploration and production business is highly competitive. Many of Goodrich's competitors have substantially larger financial resources, staffs and facilities than Goodrich. These competitors include other independent oil and gas producers, as well as major oil companies.

Government Agencies Can Increase Costs and Can Terminate or Suspend Operations. Goodrich's business is subject to federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and gas, as well as environmental and safety matters. Many of these laws and regulations have become stricter in recent years. These laws and regulations often impose greater liability on a larger number of potentially responsible parties. Under some circumstances, the State of Louisiana may require the operations of Goodrich on state leases to be suspended or terminated. These circumstances include Goodrich's failure to pay royalties and its failure to comply with safety and environmental regulations. This could have a material adverse effect on Goodrich's financial condition and operations.

Item 3. ***Legal Proceedings.***

The U.S. Environmental Protection Agency ("EPA") has identified the Company as a potentially responsible party ("PRP") for the cost of clean-up of "hazardous substances" at an oil field waste disposal site in Vermilion Parish, Louisiana. The Company estimates that the remaining cost of long-term clean-up of the site will be approximately $3.5 million, with the Company's percentage of responsibility estimated to be approximately 3.05%. As of December 31, 2003, the Company had paid $321,000 in costs related to this matter and accrued $122,500 for the remaining liability. These costs have not been discounted to their present value. The EPA and the PRPs will continue to evaluate the site and revise estimates for the long-term clean-up of the site. There can be no assurance that the cost of clean-up and the Company's percentage responsibility will not be higher than currently estimated. In addition, under the federal environmental laws, the liability costs for the clean-up of the site is joint and several among all PRPs. Therefore, the ultimate cost of the clean-up to the Company could be significantly higher than the amount presently estimated or accrued for this liability.

On February 8, 2000, the Company commenced a suit against the operator and joint owner of the Lafitte field, alleging certain items of misconduct and violations of the agreements associated primarily with the joint acquisition of and unfettered access to a license to 3-D seismic data over the field. The operator counter-claimed against Goodrich on the grounds that Goodrich was obligated to post a bond to secure the plugging and abandonment obligations in the field. On November 1, 2002 the 125th Judicial District Court of Harris County, Texas, ruled in favor of the Company stating (1) The Sale and Assignment between the Company and the operator assigned the same rights to the 3-D seismic data that the operator had pursuant to the operator's data use license agreement from Texaco Exploration and Production, Inc. ("TEPI"); and (2) Also pursuant to the terms of the Sale and Assignment, Goodrich is required to post 49% of the bond liability to TEPI at such time that TEPI requests it. A jury trial commenced in September 2003. On October 29, 2003, the jury found the operator and joint owner to be in breach of the Sale and Assignment and awarded a wholly-owned subsidiary of the Company damages in the amount of $537,500. The jury's verdict has not yet been certified by the trial judge nor has the court made a determination on the Company's claim for reimbursement of legal fees and other expenses related to the case. The timing of the outcome of these rulings is presently uncertain, however, the Company does not anticipate that the rulings will ultimately have a significant adverse impact on the Company's operations or financial position.

The Company is party to additional lawsuits arising in the normal course of business. The Company intends to defend these actions vigorously and believes, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to its financial position or results of operations.

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

None.

PART II

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

The Company's common stock is traded on the New York Stock Exchange under the symbol "GDP".

At April 9, 2004, the number of holders of record of the Company's common stock without determination of the number of individual participants in security position was 1,743 with 18,506,354 shares outstanding. High and low sales prices for the Company's common stock for each quarter during the calendar years 2003 and 2002 are as follows:

	2003		2002	
Quarter Ended	High	Low	High	Low
March 31	$4.27	$2.39	$4.63	$3.65
June 30	$4.93	$3.11	$4.88	$3.60
September 30	$5.14	$4.22	$3.65	$2.70
December 31	$5.60	$4.60	$3.01	$2.05

The Company has not paid a cash dividend on its common stock and does not intend to pay such a dividend in the foreseeable future.

Item 6. *Selected Financial Data.*

Selected Statement of Operations Data:

The following table sets forth selected financial data of the Company for each of the years in the five-year period ended December 31, 2003, which information has been derived from the Company's audited financial statements. This information should be read in connection with and is qualified in its entirety by the more detailed information in the Company's financial statements under Item 8 below and Item 7, "Management's Discussion And Analysis Of Financial Condition And Results Of Operations." As indicated in note A of the Company's financial statements, the Company has restated its previously reported Depletion, Depreciation and Amortization expense and Exploration expense for the years ended December 31, 2001 and 2002. The tax-effected amounts of these adjustments resulted in changes in the Company's previously reported Net Income (Loss) for both years.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
		As Restated			
Revenues	$32,697,692	$19,099,929	$29,894,779	$28,489,391	$14,020,574
Lease Operating Expense and Production Taxes	8,562,231	9,421,375	8,441,973	6,913,968	3,591,427
Depletion, Depreciation and Amortization	9,075,430	7,262,914*	7,523,752*	6,561,076*	4,973,410*
Exploration	2,248,802	1,019,180*	4,284,111*	2,813,332	1,656,158
General and Administrative	5,314,487	4,467,641	3,134,865	2,518,228	1,989,703
Interest Expense	1,051,198	985,185	1,290,681	4,390,331	2,810,576
Total Costs and Expenses	26,587,706	23,498,374*	26,475,918*	25,319,953*	15,559,864*
Gain (Loss) on Sale of Assets	(66,116)	2,941,062	26,779	307,299	(519,495)
Income Taxes (non cash deferred taxes)	2,121,080	(506,666)*	1,211,033*	(1,867,634)*	—
Net Income (Loss)	3,717,497	(950,717)*	2,234,607*	5,344,371*	(2,058,785)*
Preferred Stock Dividends	633,463	639,753	3,002,872	1,193,768	1,249,343
Income (Loss) Applicable to Common Stock	$ 3,084,034	$ (1,590,470)*	$ (768,265)*	$ 4,150,603*	$ (3,308,128)*
Basic Income (Loss) Per Average Common Share	$ 0.17	$ (0.09)*	$ (0.04)*	$ 0.42*	$ (0.63)*
Diluted Income (Loss) Per Average Common Share	$ 0.15	$ (0.09)*	$ (0.04)*	$ 0.32*	$ (0.63)*
Average Common Shares Outstanding Basic	18,064,329	17,908,182	17,351,375	9,903,248	5,288,011
Average Common Shares Outstanding Diluted	20,481,800	17,908,182	17,351,375	13,116,641	5,288,011

	December 31,				
	2003	2002	2001	2000	1999
		As Restated			
Selected Balance Sheet Data:					
Total Assets	$89,182,568	$78,566,897*	$81,150,438*	$64,762,740*	$55,992,100*
Total Long Term Debt	$20,000,000	$18,500,000	$24,500,000	$22,965,000	$36,953,117
Stockholders' Equity	$48,058,994	$44,607,039*	$46,827,054*	$32,024,362*	$ 6,144,592*

* See discussion of restatement of previously reported Depletion, Depreciation and Amortization expense and Exploration expense under "Restatement of 2001 and 2002 Financial Statements" in item 7 below and in note A of the Company's consolidated financial statements.

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

General

The Company was created by the combination of Patrick Petroleum Company ("Patrick") and La/Cal Energy Partners, a partnership in which it had a controlling interest ("La/Cal"), in August 1995. The combination was a reverse merger in which the Company's current management gained control of the combined company, renamed it Goodrich Petroleum Corporation and assumed Patrick's New York Stock Exchange listing.

The Company seeks to increase shareholder value by growing its oil and gas reserves, production revenues and operating cash flow. In the Company's opinion, on a long term basis, growth in oil and gas reserves and production, on a cost-effective basis, are the most important indicators of performance success for an independent oil and gas company such as Goodrich.

Management strives to increase the Company's oil and gas reserves, production and cash flow through a balanced program of capital expenditures involving acquisition, exploitation and exploration activities. The Company generally does not make capital commitments beyond one year. Goodrich develops an annual capital expenditure budget which is reviewed and approved by its board of directors on a quarterly basis and revised throughout the year as circumstances warrant. The Company takes into consideration its projected operating cash flow and externally available sources of financing, such as bank debt, when establishing its capital expenditure budget.

The Company places primary emphasis on its internally generated operating cash flow in managing its business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in the Company's Statement of Cash Flows. Management considers operating cash flow a more important indicator of its financial success than other traditional performance measures such as net income.

The Company's revenues and operating cash flow are dependent on the successful development of its inventory of capital projects, the volume and timing of its production, as well as commodity prices for oil and gas. Such pricing factors are largely beyond the Company's control, however, Goodrich employs commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on its earnings and operating cash flow.

As further described under "Results of Operations" below, the Company achieved significant increases in oil and gas production volumes and operating cash flows in the year ended December 31, 2003. These trends largely reflect the results of Goodrich's successful 2003 drilling program as the Company increased its capital expenditures in 2003 to approximately 250% of the 2002 level. Additionally, the Company benefited from a strong commodity pricing environment in 2003.

Restatement of 2001 and 2002 Financial Statements

In the course of preparing its 2003 year-end financial statements, the Company discovered a systematic error in the calculations of its non-cash depletion, depreciation and amortization expense since 1997. Accordingly, the Company has restated its previously reported depletion, depreciation and amortization expense for the years ended December 31, 2001 and 2002. Additionally, the Company has restated exploration expense due to a charge of $109,675 that was recorded in 2002 that should have been recorded in 2001. The tax-effected amounts of these adjustments resulted in changes in the Company's previously reported Statement of Operations and Balance Sheet for both years as follows:

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	As Restated	As Reported	As Restated
Depletion, Depreciation and Amortization	$ 5,452,341	$ 7,262,914	$ 6,844,751	$ 7,523,752
Exploration	1,128,855	1,019,180	4,174,436	4,284,111
Income Taxes	88,648	(506,666)	1,487,070	1,211,033
Net Income (Loss)	154,867	(950,717)	2,747,246	2,234,607
Income (Loss) Applicable to Common Stock	(484,886)	(1,590,470)	(255,626)	(768,265)
Basic Income (Loss) per Average Common Share	(0.03)	(0.09)	(0.01)	(0.04)
Diluted Income (Loss) per Average Common Share	(0.03)	(0.09)	(0.01)	(0.04)
Property and Equipment, Net	$67,560,260	$ 64,177,065	$75,093,640	$73,411,343
Total Assets	80,765,974	78,566,897	82,243,931	81,150,438
Accumulated Deficit	(9,223,359)	(11,422,436)	(8,738,473)	(9,831,966)
Total Stockholders' Equity	46,806,116	44,607,039	47,920,547	46,827,054

The tax-adjusted cumulative effect of the error on non-cash depletion, depreciation and amortization expense in years prior to December 31, 2001 resulted in a reduction of stockholders' equity as of January 1, 2001 in the amount of $580,854 and in changes in the Company's previously reported Statement of Operations and Balance Sheet for the two years prior thereto as follows:

	Year Ended December 31, 2000		Year Ended December 31, 1999	
	As Reported	As Restated	As Reported	As Restated
Depletion, Depreciation and Amortization	$ 5,953,641	$ 6,561,076	$ 4,743,608	$ 4,973,410
Income Taxes	(1,655,032)	(1,867,634)	—	—
Net Income (Loss)	5,739,204	5,344,371	(1,828,983)	(2,058,785)
Income (Loss) Applicable to Common Stock	4,545,436	4,150,603	(3,078,326)	(3,308,128)
Basic Income (Loss) per Average Common Share	0.46	0.42	(0.58)	(0.63)
Diluted Income (Loss) per Average Common Share	0.35	0.32	(0.58)	(0.63)
Property and Equipment, Net	$ 53,448,873	$ 52,555,252	$ 46,047,857	$ 45,761,671
Total Assets	65,343,594	64,762,740	56,258,552	55,992,100
Accumulated Deficit	(10,859,388)	(11,440,242)	(14,290,581)	(14,557,033)
Total Stockholders' Equity	32,605,216	32,024,362	6,411,044	6,144,592

Results of Operations

Year ended December 31, 2003 versus year ended December 31, 2002—Total revenues for the year ended December 31, 2003 amounted to $32,698,000 compared to $19,100,000 for the year ended December 31, 2002. Oil and gas sales for the year ended December 31, 2003 were $32,221,000 compared to $18,969,000 for the year ended December 31, 2002. This increase resulted from a 21% increase in oil and gas production volumes, due to several successful well completions from late 2002 and into 2003, as well as higher average prices for oil and gas. Additionally, oil and gas revenues in 2003 include sales of natural gas liquids in the amount of $762,000, resulting from processing a portion of the Company's natural gas production beginning in May 2003. The following table presents the production volumes and pricing information for the comparative periods, with the average oil and gas prices including the results of the Company's commodity hedging program as further described under "Quantitative and Qualitative Disclosures About Market Risk—Commodity Hedging Activity."

	2003		2002	
	Production	**Average Price**	**Production**	**Average Price**
Gas (Mcf)	3,361,041	$ 5.11	2,477,790	$ 3.08
Oil (Bbls)	484,444	$29.49	451,564	$25.09

Other revenues for the year ended December 31, 2003 were $477,000 compared to $131,000 for the year ended December 31, 2002, with the increase primarily due to prospect fees received by the Company in the first quarter of 2003 on the sale of interests in its Spyglass II and Tunney drilling prospects.

Lease operating expense was $6,248,000 for the year ended December 31, 2003 versus $7,757,000 for the year ended December 31, 2002, with the decrease due primarily to the Company's ongoing efforts to reduce costs on its operated properties since replacing a contract operator in June 2002. Production taxes were $2,315,000 in the year ended December 31, 2003 compared to $1,664,000 in the year ended December 31, 2002, due to an increase in production volumes as well as an increase in tax rates. Depletion, depreciation and amortization expense was $9,075,000 for the year ended December 31, 2003 versus a restated amount of $7,263,000 for the year ended December 31, 2002, with the increase substantially due to higher production volumes and rates. Exploration expense in the year ended December 31, 2003 was $2,249,000 versus $1,019,000 in the year ended December 31, 2002, due primarily to the Company recognizing dry hole costs during 2003 in the amounts of $675,000 and $141,000, respectively, related to non-operated exploratory wells drilled in offshore Australia and Calcasieu Parish, Louisiana, as well as an increase in seismic costs.

The Company recorded an impairment in the recorded value of certain oil and gas properties in the year ended December 31, 2003 in the amount of $336,000 due primarily to a sooner than anticipated depletion of reserves in non-core fields. This compares to an impairment of $342,000 recorded in the year ended December 31, 2002.

General and administrative expenses amounted to $5,314,000 in the year ended December 31, 2003 versus $4,468,000 in the year ended December 31, 2002. The most significant factors in this variance were non-cash charges of $403,000 related to the February 2003 issuance of 125,157 shares of common stock in lieu of 1,016,500 cancelled stock options, $155,000 related to the initial vesting of employee stock awards of 161,500 shares of restricted stock made primarily in February 2003 and increased legal expenses of $82,000, associated with the Company's litigation against the operator of the Lafitte field, as well as higher insurance, payroll and other administrative expenses.

Interest expense was $1,051,000 in the year ended December 31, 2003 compared to $985,000 in the year ended December 31, 2002, with the decrease in interest rates being virtually offset by an increase in borrowings.

The Company recorded deferred tax expense (not requiring cash payment) of $2,121,000 in the year ended December 31, 2003 compared to a deferred tax benefit of $507,000 in the year ended December 31, 2002, with the increase attributable to achieving pre-tax income in 2003. The Company's effective tax rate was 35.1% in 2003 and 34.7% in 2002. The Company has established a deferred tax valuation allowance for those deferred tax assets that it does not expect to realize based on estimates of future taxable income and the impact of the Company's tax attributes.

Year ended December 31, 2002 versus year ended December 31, 2001—Total revenues in 2002 amounted to $19,100,000 and were $10,796,000 (36%) lower than total revenues in 2001 due primarily to a 30% decline in production volumes resulting largely from the sale of a 30% interest in the Burrwood/West Delta 83 fields on

March 12, 2002 and lower natural gas prices, partially offset by slightly higher oil prices. Oil and gas sales were $18,969,000 for the twelve months ended 2002, compared to $29,542,000 for the twelve months ended December 31, 2001, or $10,573,000 lower due to lower oil and gas production volumes, primarily the result of the March 2002 sale of a 30% interest in the Company's Burrwood/West Delta 83 fields as further described below (see "Sale of Oil and Gas Properties to Related Party"). Oil and gas revenues were also reduced during the period due to a majority of the Company's oil and gas production being shut in temporarily as a result of Hurricane Isidore and Hurricane Lili in September and October 2002. Oil sales were reduced by $274,000 and gas sales were reduced by $739,000 for the year ended December 31, 2002, compared to reductions of $89,000 for oil sales and $972,000 for gas sales in the year ended December 31, 2001 as a result of settlement of the Company's outstanding oil and gas futures contracts. The Company recorded a gain of $2,941,000 primarily due to the sale of a 30% interest in the Burrwood/West Delta 83 fields for the twelve months ended December 31, 2002, compared to a gain of $27,000 for the twelve months ended December 31, 2001.

The following table reflects the production volumes and pricing information for the periods presented:

	2002		2001	
	Production	**Average Price**	**Production**	**Average Price**
Gas (Mcf)	2,477,790	$ 3.08	3,823,227	$ 3.97
Oil (Bbls)	451,564	$25.09	581,680	$24.67

Lease operating expense was $7,757,000 for 2002 compared to $6,576,000 for 2001, or $1,181,000 higher, due primarily to significantly increased costs associated with salt water disposal in the Burrwood/West Delta 83 fields, final billings from the prior operator of the Company's Second Bayou field, higher well insurance costs and transition costs associated with the Company assuming operations of its oil and gas properties from a contract operator in June 2002, partially offset by the March 2002 sale of a 30% interest in the Company's Burrwood/West Delta 83 fields as further described below (see "Sale of Oil and Gas Properties to Related Party"). Work was completed at the end of the second quarter to alleviate higher costs associated with compression and salt water disposal. Production taxes in 2002 were $1,664,000 compared to $1,866,000 or $202,000 lower due to lower oil and gas sales during 2002. Restated depletion, depreciation and amortization expense was $7,263,000 in 2002 versus $7,524,000 in 2001, with the decrease due primarily to lower production volumes in 2002 versus 2001.

The Company incurred $1,019,000 of exploration expense in 2002 compared to $4,284,000 in 2001, or $3,265,000 lower, due primarily to dry hole and seismic costs of $-0- and $130,000 respectively in 2002, compared to $1,604,000 and $994,000 respectively in 2001.

The Company recorded an impairment in the recorded value of certain oil and gas properties in 2002 in the amount of $342,000 due primarily to a sooner than anticipated depletion of reserves in non-core fields. This compares to an impairment of $1,801,000 recorded in 2001.

General and administrative expenses amounted to $4,468,000 for the twelve months ended December 31, 2002 versus $3,135,000 in 2001 or $1,333,000 higher, due primarily to legal costs of $983,000 attributable to litigation against the operator and joint owner of the Company's Lafitte field and added salaries associated with the Company assuming operations from its contract operator.

Interest expense was $985,000 in the twelve months ended December 31, 2002 compared to $1,291,000 in the twelve months ended December 31, 2001, or $306,000 lower, due primarily to lower average debt outstanding, reflecting debt reduction from proceeds of a property sale, and a lower average effective interest rate for the twelve months ended December 31, 2002.

The Company recorded a deferred tax benefit of $507,000 in 2002 compared to the recording of a deferred tax expense (not requiring current cash payment) of $1,211,000 in 2001 with the decrease entirely attributable to the pre-tax loss in 2002.

Preferred stock dividends were $640,000 in 2002 compared to $3,003,000 in 2001. In 2002, such amount consisted solely of cash dividends paid on the Company's Series A preferred stock whereas the 2001 amount includes cash dividends paid on the Company's Series A preferred stock in the amount of $626,000, as well as a non-cash charge related to the conversion of the Company's Series B preferred stock into common stock in the amount of $2,377,000.

Liquidity and Capital Resources

Net cash provided by operating activities was $17,048,000 in the year ended December 31, 2003, compared to $5,349,000 in the year ended December 31, 2002 and $15,790,000 in the year ended December 31, 2001. The increase in the 2003 period reflects higher oil and gas revenues and lower lease operating expenses, partially offset by an increase in general and administrative expenses. The decrease in the 2002 period reflects substantially lower oil and gas revenues due to the March 2002 sale of a 30% interest in the Company's Burrwood/West Delta 83 fields as further described below (see "Sale of Oil and Gas Properties to Related Party"). The operating cash flow amounts are net of changes in current assets and current liabilities, which resulted in a $519,000 decrease in working capital in the year ended December 31, 2003, compared to increases of $1,589,000 and $44,000 in the years ended December 31, 2002 and 2001, respectively.

Net cash used in investing activities was $19,500,000 in the year ended December 31, 2003, compared to net cash provided by investing activities of $4,743,000 in the year ended December 31, 2002 and net cash used in investing activities of $31,846,000 in the year ended December 31, 2001. In the year ended December 31, 2003, capital expenditures totaled $19,898,000 as the Company participated in the drilling of nine new wells in its Burrwood/West Delta 83, Lafitte and Bethany-Longstreet fields (eight of which were successfully completed). In the same period, the Company sold its interests in the South Drew field in Louisiana and two smaller properties in Texas for gross proceeds of $399,000. In the year ended December 31, 2002, capital expenditures totaled $8,079,000 as the Company participated in the drilling of two new wells, however, such expenditures were more than offset by proceeds from property sales of $12,823,000, primarily due to the sale of a 30% interest in the Company's Burrwood/West Delta 83 fields as further described below (see "Sale of Oil and Gas Properties to Related Party"). In the year ended December 31, 2001, capital expenditures totaled $32,253,000 as Goodrich participated in the drilling of seven new wells and completed minor property sales totaling $407,000.

Net cash provided by financing activities was $589,000 in the year ended December 31, 2003, compared to net cash used in financing activities of $6,989,000 in the year ended December 31, 2002 and net cash provided by financing activities of $12,772,000 in the year ended December 31, 2001. In the year ended December 31, 2003, net borrowings under the Company's senior credit facility provided cash of $1,500,000 toward funding of capital expenditures, while preferred stock dividends and production payments required cash of $1,040,000. In the year ended December 31, 2002, net repayments under the Company's senior credit facility reduced cash by $6,000,000, while preferred stock dividends and production payments required additional cash of $1,017,000. The cash resources for the net debt repayments in the year ended December 31, 2002 were provided by the sale of an interest in the Company's Burrwood/West Delta 83 fields as further described below (see "Sale of Oil and Gas Properties to Related Party"). In the year ended December 31, 2001, the Company completed a public stock offering resulting in net cash proceeds of $13,069,000 while net borrowings under the Company's senior credit facility provided additional cash of $1,482,000 and preferred stock dividends, production payments and restricted cash funding required cash of $1,971,000.

For the year 2004, the Company has preliminarily budgeted total capital expenditures of approximately $25 million, which includes the Company's share of the subsequent exploration and development costs related to two recent property acquisitions in Louisiana, as further described below (see "Recent Property Acquisitions"). Subject to current economics and financial resources, the Company expects to finance its capital expenditures out of operating cash flow and available bank credit, as further described below (see "Senior Credit Facility"). The Company's senior credit facility includes certain financial covenants with which the Company was in compliance as of December 31, 2003. The Company does not anticipate a lack of borrowing capacity under its senior credit facility in the foreseeable future due to an inability to meet any such financial covenants.

Recent Property Acquisitions

In the third quarter of 2003, the Company announced its acquisition of interests in two non-producing properties in Louisiana that required minimal initial expenditures. Pursuant to the first acquisition, the Company obtained, via farmout, the right to drill and earn all rights, excluding exploration rights to the Crane zone of the Pettit formation, in approximately 18,000 acres in the Bethany-Longstreet field in northwest Louisiana. The Company will retain continuous drilling rights to the entire block so long as it drills at least one well every 120 days. For each productive well drilled under the agreement, the Company will earn an assignment to 160 acres. The Company has begun exploration and development drilling activities in the field and had completed three successful wells as of December 31, 2003. The Company anticipates drilling additional wells on the block in 2004 and expects that its working interests in the wells will range between 50% and 70%.

Under the second acquisition, the Company obtained certain rights in the Plumb Bob field located in St. Martin Parish in southern Louisiana. The rights include oil and gas leases covering approximately 450 acres, 3-D seismic permits with oil and gas lease options covering approximately 17,000 acres, seven existing shut-in wellbores, where the Company has identified recompletion projects, and the rights to acquire related production facilities and pipelines upon establishment of production. The Company's plans include a workover and well reactivation program, the shooting of a 32 square mile 3-D seismic survey and post 3-D exploitation and development drilling activities. The Company has begun workover drilling activities in the field and had restored production capability in three wells as of December 31, 2003. The 3-D seismic shoot began during the fourth quarter of 2003 and is expected to be completed in the second quarter of 2004. Based on its expected 70% working interest, the Company has budgeted net capital expenditures in the Plumb Bob field of up to $3.7 million in the full year 2004.

Sale of Oil and Gas Properties to Related Party

On March 12, 2002, the Company monetized a portion of the value created in its Burrwood/West Delta 83 fields by selling a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, in such fields for $12 million to Malloy Energy Company, LLC ("MEC") led by Patrick E. Malloy, III and participated in by Sheldon Appel, who was a member of the Company's Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of the Company's Board of Directors (Mr. Malloy is currently Chairman of the Company's Board of Directors and Mr. Appel retired from the Board of Directors in February 2004). The sale price was determined by discounting the present value of the acquired interest in the fields' proved, probable and possible reserves using prevailing oil and gas prices. The Company retained an approximate 65% working interest in the existing production and shallow rights, and a 32.5% working interest in the deep rights after the close of the transaction. In conjunction with the sale, MEC provided a $7.7 million line of credit which reduced to $5.0 million on January 1, 2003. The credit line is subordinate to the Company's senior credit facility and can be used for acquisitions, drilling, development and general corporate purposes until December 31, 2004. MEC retains the option to convert the amount outstanding under the credit line, and/or provide cash on any unused credit, into 30% of the Company's working interests in any acquisition(s) the Company makes in Louisiana prior to January 1, 2005. MEC has elected to participate for 30% of the Company's working interest in the two Louisiana property acquisitions announced by the Company in the third quarter of 2003 (see "Recent Property Acquisitions"). Since the Company has made no borrowings under the MEC credit line to date, MEC funded its share of the acquisition costs and will fund its share of the subsequent capital costs related to these acquisitions on a direct basis, rather than by converting borrowings under the credit line.

The Company recorded a non-recurring gain of approximately $2.4 million in the first quarter of 2002 as a result of the MEC sale. The proceeds were used to reduce outstanding debt under its senior credit facility.

Senior Credit Facility

On November 9, 2001, the Company established a $50,000,000 senior credit facility with BNP Paribas, with an initial borrowing base of $25,000,000 and a three year term. In December 2003, the borrowing base was redetermined to be $28,000,000 and BNP Paribas and the Company agreed to extend the term of the senior credit facility for an additional two years, subject to periodic redeterminations of the borrowing base. The Company's borrowings outstanding under the credit facility amounted to $20,000,000 as of December 31, 2003 and $19,000,000 as of April 9, 2004.

Interest on borrowings under the senior credit facility accrue at a rate calculated, at the option of the Company, at either the BNP Paribas base rate plus 0.00% to 0.50%, or LIBOR plus 1.50%—2.50%, depending on borrowing base utilization. Interest on LIBOR-rate borrowings is due and payable on the last day of its respective interest period. Accrued interest on each base-rate borrowing is due and payable on the last day of each quarter. As extended, the senior credit facility will mature on December 29, 2006. The credit facility requires that the Company pay a 0.375% per annum commitment fee, payable in quarterly installments based on the Company's borrowing base utilization. Prior to maturity, no principal payments are required so long as the maximum borrowing base amount exceeds the amounts outstanding under the credit facility. The credit facility requires the Company to monitor tangible net worth and maintain a current ratio and an interest coverage ratio above prescribed levels. As of December 31, 2003, the Company was in compliance with all such requirements. Substantially all the Company's assets are pledged to secure the senior credit facility.

In February 2003, the Company entered into three separate interest rate swaps with BNP Paribas covering a three year period, as further described below, and in February 2004, entered into another interest rate swap with BNP Paribas for an additional one year period (see "Quantitative and Qualitative Disclosures About Market Risk—Debt and debt-related derivatives").

Contractual Obligations

At December 31, 2003, the Company had the following contractual obligations outstanding under its long term debt, production payment and operating lease agreements (as of December 31, 2003, the Company had no material purchase obligations for goods or services that were not incurred in the ordinary course of business):

	Total	2004	2005-2006	2007-2008	After 2008
Long-term debt	$20,000,000	—	$20,000,000	—	—
Production Payment	$ 610,000	$610,000		—	—
Operating lease obligation	$ 1,044,000	$331,000	$ 614,000	$99,000	—

Critical Accounting Policies and Estimates

Critical accounting policies are defined as those that are reflective of significant judgments and uncertainties and potentially result in materially different results under different assumptions and conditions. The Company has prepared its consolidated financial statements in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts in these financial statements and accompanying notes. Actual results could differ from those estimates under different assumptions or conditions. Application of certain of the Company's accounting policies requires a significant amount of estimates. These accounting policies are described below.

- *Proved oil and natural gas reserves*—Proved reserves are defined by the Securities and Exchange Commission (SEC) as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although the Company's external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by the Company. The Company cannot predict the types of reserve revisions that will be required in future periods.

- *Successful efforts accounting*—The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells, as well as other exploration expenditures such as seismic costs, are expensed and can have a significant effect on operating results. Successful exploration drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by engineers.
- *Impairment of properties*—The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment in the Consolidated Balance Sheet to ensure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. Performing these evaluations requires a significant amount of judgment since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. The Company cannot predict the amount of impairment charges that may be recorded in the future.
- *Property retirement obligations*—The Company is required to make estimates of the future costs of the retirement obligations of its producing oil and gas properties. This requirement necessitates the Company to make estimates of its property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.
- *Income taxes*—The Company is subject to income and other related taxes in areas in which it operates. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by the Company. The Company periodically evaluates its tax operating loss and other carryforwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in its financial statements. In prior years, the Company has reported a net deferred tax asset on its Consolidated Balance Sheet, after deduction of the related valuation allowance, which has been determined on the basis of management's estimation of the likelihood of realization of the gross deferred tax asset.

New Accounting Pronouncements

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the periods in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. As of January 1, 2003, the adoption of SFAS No. 143 resulted in the Company recording a cumulative effect of an accounting change in the amount of $205,000. The estimation of the liability involves the projection of future costs to plug and abandon individual wells. These estimates are based on current costs inflated to the end of the well's economic life and discounted back to the well's origination date. The liability will be accreted at the estimated discount rate to the expected cash required to settle the liability. The estimate requires management's judgment with respect to the future plugging and abandonment costs, the life of the well, and the inflation and discount factors used. Changes in these estimates can significantly impact the amount of the liability.

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133, *Accounting for Derivatives and Hedging Activities*. This statement (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, (2) clarifies when a derivative contains a financing component, and (3) amends the definition of an underlying derivative to conform to Financial Accounting Standards Board Interpretation No. 45. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, with all provisions applied prospectively. The Company adopted SFAS No. 149, effective July 1, 2003, and the adoption had no impact on its financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify an instrument that is within its scope as a liability. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and is effective at the beginning of the first interim period beginning after June 15, 2003, although in November 2003, the FASB deferred certain provisions of SFAS No. 150. As of December 31, 2003, the Company had no financial instruments within the scope of SFAS No. 150.

In July 2003, the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and it does not provide the additional disclosures for these assets. The EITF has added the discussion of oil and gas mineral leases to its agenda, which may result in a change in the recording and disclosure of oil and gas mineral leases. Should the EITF determine that oil and gas mineral leases are intangible assets, the Company would reclassify $6,409,000 and $6,563,000 as intangible undeveloped mineral interests at December 31, 2003 and 2002, respectively. In addition, a reclassification of $5,879,000 and $4,925,000 would be made as intangible developed mineral interests at December 31, 2003 and 2002, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on the Company's understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property and Equipment on the Consolidated Balance Sheet
- The Company does not believe that its net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements

In March 2004, the FASB issued an exposure draft on accounting for stock-based compensation. The exposure draft reflects the FASB's tentative conclusion that the fair value of stock options should be expensed in companies' financial statements for years ending after December 31, 2004. The exposure draft also includes the FASB's tentative decisions regarding how equity-based awards are likely to be valued, expensed, and classified. The Company will continue to monitor developments with respect to the exposure draft to determine the potential impact on its financial statements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodity Hedging Activity

The Company enters into futures contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of its production. The Company considers these to be hedging activities and, as such, monthly settlements on these contracts are reflected in its crude oil and natural gas sales. The Company's strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to hedge between 30% and 70% of its production. As of December, 31, 2003, all of the commodity hedges utilized by the Company were in the form of fixed price swaps, where the Company receives a fixed price and pays a floating price based on NYMEX quoted prices. As of December 31, 2003, the Company's open forward position on its outstanding commodity hedging contracts, all of which were with BNP Paribas, was as follows:

Crude Oil

700 barrels of oil per day "swap" at $28.59 for January 2004 through June 2004; and
300 barrels of oil per day "swap" at $30.92 for January 2004 through June 2004; and
700 barrels of oil per day "swap" at $28.20 for July 2004 through December 2004

Natural Gas

3,000 MMBtu per day "swap" at $5.00 for January 2004 through December 2004

The hedging contracts summarized above fall within the Company's targeted range of 30% to 70% of its estimated net oil and gas production volumes for the applicable periods of 2004. The fair value of the crude oil and natural gas hedging contracts in place at December 31, 2003 resulted in a liability of $1,257,000. Hedge ineffectiveness results from differences in the NYMEX contract terms and the physical location, grade and quality of the Company's oil and gas production. Based on oil and gas pricing in effect at December 31, 2003, a hypothetical 10% increase in oil and gas prices would have increased the liability to $2,800,000 while a hypothetical 10% decrease in oil and gas prices would have resulted in a $320,000 asset. Subsequent to December 31, 2003, the Company entered into the following crude oil and natural gas hedging contracts with BNP Paribas:

300 barrels of oil per day "swap" at $30.25 for July 2004 through December 2004
3,000 MMBtu per day "swap" at $5.41 for April 2004 through October 2004
3,000 MMBtu per day "swap" at $6.20 for November 2004 through December 2004
6,000 MMBtu per day "swap" at $6.27 for January 2005 through March 2005

Price Fluctuations and the Volatile Nature of Markets

Despite the measures taken by the Company to attempt to control price risk, the Company remains subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond the Company's control. Domestic crude oil and gas prices could have a material adverse effect on the Company's financial position, results of operations and quantities of reserves recoverable on an economic basis.

Debt and Debt-Related Derivatives

In February 2003, the Company entered into three separate interest rate swaps with BNP Paribas covering a three year period. The first interest rate swap, which has an effective date of February 26, 2003 and a maturity date of February 26, 2004 is for $18,000,000 with a LIBOR swap rate of 1.53%. The second interest rate swap, which has an effective date of February 26, 2004 and a maturity date of November 8, 2004, is for $18,000,000 with a LIBOR swap rate of 2.25%. The third interest rate swap, which has an effective date of November 8, 2004 and a maturity date of February 26, 2006, is for $18,000,000 with a LIBOR swap rate of 3.46%. The fair value of the interest rate swap contracts in place at December 31, 2003, resulted in a liability of $278,000. Based on interest rates at December 31, 2003, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the liability. Subsequent to December 31, 2003, the Company entered into a fourth interest rate swap contract with BNP Paribas, which has an effective date of February 26, 2006 and a maturity date of February 26, 2007, for $23,000,000 with a LIBOR swap rate of 4.08%.

Disclosure Regarding Forward-Looking Statement

This Annual Report on Form 10-K includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical facts included in this Annual Report on Form 10-K regarding reserve estimates, planned capital expenditures, future oil and gas production and prices, future drilling activity, the Company’s financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary from one another. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revisions of such estimates and such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Additional important factors that could cause actual results to differ materially from the Company’s expectations include changes in oil and gas prices, changes in regulatory or environmental policies, production difficulties, transportation difficulties and future drilling results. All subsequent written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by such factors.

Item 8. ***Financial Statements and Supplementary Data***

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Goodrich Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and stockholders' equity and other comprehensive income for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note A, the Company has restated its 2002 and 2001 consolidated financial statements.

As discussed in Note B to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations and, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

KPMG LLP

Shreveport, Louisiana
April 9, 2004

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002 (as restated)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,488,852	$ 3,351,380
Cash held temporarily for stockholders	3,886,988	—
Accounts receivable		
Trade and other, net of allowance	3,500,095	3,111,240
Accrued oil and gas revenue	2,829,082	3,141,968
Prepaid insurance and other	351,527	884,318
Total current assets	12,056,544	10,488,906
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method)	118,682,309	105,971,168
Furniture, fixtures and equipment	661,842	567,908
	119,344,151	106,539,076
Less accumulated depletion, depreciation, and amortization	(44,381,223)	(42,362,011)
Net property and equipment	74,962,928	64,177,065
OTHER ASSETS		
Restricted cash	2,039,000	2,039,000
Deferred taxes	—	1,634,356
Other	124,096	227,570
Total other assets	2,163,096	3,900,926
TOTAL ASSETS	$ 89,182,568	$ 78,566,897
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 6,707,583	$ 6,927,158
Accrued liabilities	1,483,329	1,564,583
Liability for funds held temporarily for stockholders	3,886,988	—
Fair value of oil and gas derivatives	1,257,442	1,108,428
Fair value of interest rate derivatives	277,938	—
Current portion of other non-current liabilities	91,600	125,000
Total current liabilities	13,704,880	9,725,169
LONG TERM DEBT	20,000,000	18,500,000
OTHER NON-CURRENT LIABILITIES		
Production payment payable and other	704,643	978,321
Accrued abandonment costs	6,509,586	4,756,368
Deferred taxes	204,465	—
Total liabilities	41,123,574	33,959,858
STOCKHOLDERS' EQUITY		
Preferred stock; authorized 10,000,000 shares:		
Series A convertible preferred stock, par value $1.00 per share; issued and outstanding 791,968 shares (liquidation preference $10 per share, aggregating to $7,919,680)	791,968	791,968
Common stock; par value $0.20 per share:		
Authorized 50,000,000 shares; issued and outstanding 18,130,011 and 17,914,325 shares	3,626,002	3,582,864
Additional paid-in capital	53,359,023	52,333,738
Accumulated deficit	(8,338,403)	(11,422,437)
Unamortized restricted stock awards	(381,598)	—
Accumulated other comprehensive (loss)	(997,998)	(679,094)
Total stockholders' equity	48,058,994	44,607,039
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 89,182,568	$ 78,566,897

See notes to consolidated financial statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2003	2002 (as restated)	2001 (as restated)
REVENUES			
Oil and gas revenues	$32,220,813	$18,969,227	$29,541,662
Other	476,879	130,702	353,117
Total revenues	32,697,692	19,099,929	29,894,779
EXPENSES			
Lease operating expense	6,247,588	7,757,310	6,576,247
Production taxes	2,314,643	1,664,065	1,865,726
Depletion, depreciation and amortization	9,075,430	7,262,914	7,523,752
Exploration	2,248,802	1,019,180	4,284,111
Impairment of oil and gas properties	335,558	342,079	1,800,536
General and administrative	5,314,487	4,467,641	3,134,865
Interest expense	1,051,198	985,185	1,290,681
Total costs and expenses	26,587,706	23,498,374	26,475,918
GAIN (LOSS) ON SALE OF ASSETS	(66,116)	2,941,062	26,779
INCOME (LOSS) BEFORE INCOME TAXES	6,043,870	(1,457,383)	3,445,640
Income taxes	2,121,080	(506,666)	1,211,033
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT	3,922,790	(950,717)	2,234,607
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE NET OF TAX	(205,293)	—	—
NET INCOME (LOSS)	3,717,497	(950,717)	2,234,607
Preferred stock dividends paid in cash	633,463	639,753	626,331
Conversion premium on Series B preferred stock	—	—	2,376,541
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 3,084,034	$ (1,590,470)	$ (768,265)
NET INCOME (LOSS) PER COMMON SHARE—BASIC			
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT	$ 0.22	$ (0.05)	$ 0.13
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING	(0.01)	—	—
NET INCOME (LOSS)	$ 0.21	$ (0.05)	$ 0.13
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 0.17	$ (0.09)	$ (0.04)
NET INCOME (LOSS) PER COMMON SHARE—DILUTED			
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT	$ 0.19	$ (0.05)	$ 0.13
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING	(0.01)	—	—
NET INCOME (LOSS)	$ 0.18	$ (0.05)	$ 0.13
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 0.15	$ (0.09)	$ (0.04)
AVERAGE COMMON SHARES OUTSTANDING—BASIC	18,064,329	17,908,182	17,351,375
AVERAGE COMMON SHARES OUTSTANDING—DILUTED	20,481,800	17,908,182	17,351,375

See notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	2002 (as restated)	2001 (as restated)
OPERATING ACTIVITIES			
Net income (loss)	$ 3,717,497	$ (950,717)	$ 2,234,607
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	9,075,430	7,262,914	7,523,752
Deferred income taxes	2,010,538	(506,666)	1,211,033
Dry hole costs	815,593	—	1,604,226
Amortization of leasehold costs	473,556	351,719	1,017,426
Impairment of oil and gas properties	335,558	342,079	1,800,536
Non-cash charge for stock issued for cancelled options	403,006	—	—
Cumulative effect of change in accounting principle	315,835	—	—
(Gain) Loss on sale of asset	66,116	(2,941,062)	(26,779)
Other non-cash items	353,824	202,008	380,889
Net change in:			
Accounts Receivable	(75,969)	(1,971,405)	513,719
Prepaid insurance and other	(142,209)	(839,678)	93,945
Accounts payable	(219,575)	4,528,721	(645,041)
Accrued liabilities	(81,254)	(129,091)	81,709
Net cash provided by operating activities	17,047,946	5,348,822	15,790,022
INVESTING ACTIVITIES			
Capital expenditures	(19,898,363)	(8,079,463)	(32,252,774)
Proceeds from sales of assets	398,599	12,822,591	406,779
Net cash provided by (used in) investing activities	(19,499,764)	4,743,128	(31,845,995)
FINANCING ACTIVITIES			
Net proceeds from public offering of common stock	—	—	13,069,170
Principal payments of bank borrowings	(1,600,000)	(13,500,000)	(13,690,000)
Net proceeds from bank borrowings	3,100,000	7,500,000	15,172,139
Exercise of stock options and warrants	128,887	28,000	191,796
Production payments	(406,134)	(377,518)	(544,863)
Preferred stock dividends	(633,463)	(639,753)	(626,331)
Net change in restricted cash	—	—	(799,000)
Net cash provided by (used in) financing activities	589,290	(6,989,271)	12,772,911
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,862,528)	3,102,679	(3,283,062)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	3,351,380	248,701	3,531,763
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 1,488,852	$ 3,351,380	$ 248,701

See notes to consolidated financial statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND OTHER COMPREHENSIVE INCOME

Years Ended December 31, 2003, 2002 and 2001

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-In Capital	Accumulated Deficit	Unamortized Restricted Stock Awards	Accumulated Other Comprehensive Income	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Shares	Amount					
								(Restated)			(Restated)
Balance at January 1, 2001	791,968	$791,968	660,839	$ 660,839	13,318,920	$2,663,784	$39,348,013	$(10,859,389)	$ —	$ —	$32,605,215
Cumulative effect of restatement, net of tax of $312,767	—	—	—	—	—	—	—	(580,854)	—	—	(580,854)
Net Income	—	—	—	—	—	—	—	2,234,607	—	—	2,234,607
Cumulative Effect of Accounting Change, net of tax of $1,365,253	—	—	—	—	—	—	—	—	—	(2,535,468)	(2,535,468)
Other Comprehensive Income (Loss); Net of Tax											
Net Derivative Gain, net of tax of $967,796	—	—	—	—	—	—	—	—	—	1,797,336	1,797,336
Reclassification Adjustment, net of tax of $402,006	—	—	—	—	—	—	—	—	—	746,583	746,583
Total Comprehensive Income											1,662,204
Issuance of Common Stock	—	—	—	—	3,000,000	600,000	12,469,170	—	—	—	13,069,170
Preferred Stock Dividends	—	—	—	—	—	—	—	(626,331)	—	—	(626,331)
Exercise of Stock Options and Warrants	—	—	—	—	382,796	76,559	115,237	—	—	—	191,796
Conversion of Series B Preferred Stock to Common Stock	—	—	(660,839)	(660,839)	1,189,510	237,902	317,937	—	—	—	(105,000)
Director Stock Grant	—	—	—	—	5,130	1,026	28,974	—	—	—	30,000
Balance at December 31, 2001	791,968	$791,968	—	$ —	17,896,356	$3,579,271	$52,279,331	$ (9,831,967)	$ —	$ 8,451	$46,827,054
Net Loss	—	$ —	—	$ —	—	$ —	$ —	$ (950,717)	$ —	$ —	$ (950,717)
Other Comprehensive Income (Loss); Net of Tax											
Net Derivative (Loss), net of tax of $724,642	—	—	—	—	—	—	—	—	—	(1,345,763)	(1,345,763)
Reclassification Adjustment, net of tax of $354,425	—	—	—	—	—	—	—	—	—	658,218	658,218
Total Comprehensive Loss											(1,638,262)
Preferred Stock Dividends	—	—	—	—	—	—	—	(639,753)	—	—	(639,753)
Exercise of Stock Options and Warrants	—	—	—	—	10,667	2,133	25,867	—	—	—	28,000
Director Stock Grant	—	—	—	—	7,302	1,460	28,540	—	—	—	30,000
Balance at December 31, 2002	791,968	$791,968	—	$ —	17,914,325	$3,582,864	$52,333,738	$(11,422,437)	$ —	$ (679,094)	$44,607,039
Net Income	—	$ —	—	$ —	—	$ —	$ —	$ 3,717,497	—	$ —	$ 3,717,497
Other Comprehensive Income (Loss); Net of Tax											
Net Derivative (Loss), net of tax of $1,204,397	—	—	—	—	—	—	—	—	—	(2,236,739)	(2,236,739)
Reclassification Adjustment, net of tax of $1,032,680	—	—	—	—	—	—	—	—	—	1,917,835	1,917,835
Total Comprehensive Income											3,398,593
Issuance of Common Stock	—	—	—	—	125,157	25,032	377,974	—	—	—	403,006
Issuance and Amortization of Restricted Stock	—	—	—	—	—	—	536,530	—	(381,598)	—	154,932
Preferred Stock Dividends	—	—	—	—	—	—	—	(633,463)	—	—	(633,463)
Exercise of Stock Options and Warrants	—	—	—	—	90,529	18,106	110,781	—	—	—	128,887
Balance at December 31, 2003	791,968	$791,968	—	$ —	18,130,011	$3,626,002	$53,359,023	$ (8,338,403)	$(381,598)	$ (997,998)	$48,058,994

See notes to consolidated financial statements

GOODRICH PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003

NOTE A—General Information

Description of Business

The Company is in the primary business of exploration and production of crude oil and natural gas. The Company's subsidiaries have interests in such operations in four states, primarily in Louisiana and Texas.

Restatement of 2001 and 2002 Financial Statements

In the course of preparing its 2003 year-end financial statements, the Company discovered a systematic error in the calculations of its non-cash depletion, depreciation and amortization expense since 1997. Essentially, the Company had been allocating the acquisition and development costs of its oil and gas properties over total proved reserves in each field rather than segregating the costs between those costs to be allocated over proved developed reserves versus those costs to be allocated over total proved reserves. Accordingly, the Company has restated its previously reported depletion, depreciation and amortization expense for the years ended December 31, 2001 and 2002. Such restated amounts reflect reallocations of the purchase price of three oil and gas property acquisitions completed prior to January 1, 2001, based upon analyses of contemporaneous documentation from the time of the acquisitions. Additionally, the Company has restated exploration expense due to a charge of $109,675 that was recorded in 2002 that should have been recorded in 2001. The tax-effected amounts of these adjustments resulted in changes in the Company's previously reported Statement of Operations and Balance Sheet for both years as follows:

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	As Restated	As Reported	As Restated
Depletion, Depreciation and Amortization	$ 5,452,341	$ 7,262,914	$ 6,844,751	$ 7,523,752
Exploration	1,128,855	1,019,180	4,174,436	4,284,111
Income Taxes	88,648	(506,666)	1,487,070	1,211,033
Net Income (Loss)	154,867	(950,717)	2,747,246	2,234,607
Income (Loss) Applicable to Common Stock	(484,886)	(1,590,470)	(255,626)	(768,265)
Basic Income (Loss) per Average Common Share	(0.03)	(0.09)	(0.01)	(0.04)
Diluted Income (Loss) per Average Common Share	(0.03)	(0.09)	(0.01)	(0.04)
Property and Equipment, Net	$67,560,260	$ 64,177,065	$75,093,640	$73,411,343
Total Assets	80,765,974	78,566,897	82,243,931	81,150,438
Accumulated Deficit	(9,223,359)	(11,422,436)	(8,738,473)	(9,831,966)
Total Stockholders' Equity	46,806,116	44,607,039	47,920,547	46,827,054

The tax-adjusted cumulative effect of the error on non-cash depletion, depreciation and amortization expense in years prior to December 31, 2001 resulted in a reduction of stockholders' equity as of January 1, 2001 in the amount of $580,854. The restatement adjustments had no impact on cash flow from operating, investing or financing activities.

NOTE B—Summary of Significant Accounting Policies

Principles of Consolidation—The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiaries. Significant intercompany balances and transactions have been eliminated in consolidation.

Revenue Recognition—Revenues from the production of crude oil and natural gas properties in which the Company has an interest with other producers are recognized on the entitlements method. The Company records an asset or liability for natural gas balancing when the Company has purchased or sold more than its working interest share of natural gas production, respectively. At December 31, 2003 and 2002, the assets and liabilities for gas balancing were immaterial. Differences between actual production and net working interest volumes are routinely adjusted. These differences are not significant.

Property and Equipment—The Company uses the successful efforts method of accounting for exploration and development expenditures. Leasehold acquisition costs are capitalized. When proved reserves are found on an undeveloped property, leasehold cost is reclassified to proved properties. Significant undeveloped leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Cost of all other undeveloped leases is amortized over the estimated average holding period of the leases.

Costs of exploratory drilling are initially capitalized, but if proved reserves are not found, the costs are subsequently expensed. All other exploratory costs are charged to expense as incurred. Development costs are capitalized, including the cost of unsuccessful development wells.

The Company recognizes an impairment when the net of future cash inflows expected to be generated by an identifiable long-lived asset and cash outflows expected to be required to obtain those cash inflows is less than the carrying value of the asset. The Company performs this comparison for its oil and gas properties on a field-by-field basis using the Company's estimates of future commodity prices and proved and probable reserves. The amount of such loss is measured based on the difference between the discounted value of such net future cash flows and the carrying value of the asset. The Company recorded such impairments in 2003, 2002 and 2001 in the amounts of $336,000, $342,000 and $1,801,000 respectively. The impairments were generally the result of certain non-core fields depleting earlier than anticipated.

Depreciation and depletion of producing oil and gas properties are provided under the unit-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs. As described elsewhere in Note B, the Company adopted SFAS No. 143 on January 1, 2003. Under SFAS No. 143, estimated asset retirement costs are generally recognized when the asset is placed in service, and are amortized over proved reserves using the units of production method. Prior to the adoption of SFAS No. 143, estimated dismantlement, abandonment and site restoration costs, net of salvage value, were generally recognized using the units of production method and were included in depreciation expense. Asset retirement costs are estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates.

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in income. All other dispositions, retirements, or abandonments are reflected in accumulated depreciation, depletion, and amortization.

Cash and Cash Equivalents—Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase.

Income Taxes—The Company follows the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*, which requires income taxes be accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Earnings Per Share—Basic income per common share is computed by dividing net income available for common stockholders, for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income available for common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive common shares.

Derivative Instruments and Hedging Activities—The Company utilizes derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging its exposure to fluctuations in the price of crude oil and natural gas and to hedge its exposure to changing interest rates.

Effective January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138. See also Note I for further information about the Company's derivative instruments. In accordance with the transition provisions of SFAS No. 133, the Company recorded a cumulative adjustment of $2,535,000 (net of $1,365,000 in income taxes) in accumulated other comprehensive income to recognize at fair value all derivatives that were designated as cash flow hedging instruments. There was no cumulative effect on earnings. The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to market through earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items, as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the Statement of Operations, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings.

Ineffective portions of a cash flow hedging derivative's change in fair value are recognized currently in earnings as oil and gas revenues. If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in other comprehensive income is recognized over the period anticipated in the original hedge transaction.

Stock Based Compensation—While SFAS No. 123, *Accounting for Stock-Based Compensation*, permits entities to recognize as expense, over the vesting period, the fair value of all stock-based awards on the date of grant, it also allows entities to continue to apply the provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and provide pro forma net income and pro forma earnings per share and other disclosures for employee stock option grants made in 1995 and future years as if the fair-value-based method defined in SFAS No. 123 had been applied. The Company has elected to continue to apply the provisions of APB Opinion No. 25 and provide the disclosure provisions of SFAS No. 123. For stock based compensation that vests on a prorata basis where the award is fixed at the grant date, the Company has elected to amortize those costs using straight line method over the life of the award.

The Company applies APB Opinion No. 25 in accounting for its plans and, accordingly, no compensation cost has been recognized for its stock options in the financial statements. Had the Company determined compensation cost based on the fair value at the grant date for its stock options under SFAS No. 123, the Company's net income (loss) would have been reduced to the pro forma amounts indicated below:

		As Restated	
	2003	2002	2001
Net income (loss)			
As reported	$3,717,497	$ (950,717)	$ 2,234,607
Restricted stock compensation expense included in net income, net of tax	154,932	—	—
Stock based compensation expense at fair value, net of tax	(195,878)	(947,097)	(683,651)
Pro forma	$3,676,551	$(1,897,814)	$ 1,550,956
Net income (loss) applicable to common stock			
As reported	$3,084,034	$(1,590,470)	$ (768,265)
Restricted stock compensation expense included in net income, net of tax	154,932	—	—
Stock based compensation expense at fair value, net of tax	(195,878)	(947,097)	(683,651)
Pro forma	$3,043,088	$(2,537,567)	$(1,451,916)
Net income (loss) per share			
As reported, basic	$ 0.17	$ (0.09)	$ (0.04)
Pro forma, basic	0.17	(0.14)	(0.08)
As reported, diluted	0.15	(0.09)	(0.04)
Pro forma, diluted	0.15	(0.14)	(0.08)

Commitments and Contingencies—Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, which are probable of realization, are separately recorded, and are not offset against the related environmental liability.

Use of Estimates—Management of the Company has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

New Accounting Pronouncements—Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the periods in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. Prior to the adoption of SFAS No. 143, the Company recorded liabilities for the abandonment of oil and gas properties only in its two largest fields, with such liabilities amounting to $4,881,000 as of December 31, 2002. In accordance with the transition provisions of SFAS No. 143, the Company recorded an adjustment to recognize additional estimated liabilities for the abandonment of oil and gas properties, as of January 1, 2003, in the amount of $1,408,000, and additional oil and gas properties, net of accumulated depletion, depreciation and amortization, in the amount of $1,092,000. To recognize the cumulative effect of this change in accounting principle, the Company recorded a charge to earnings as of January 1, 2003 in the amount of $205,000, reflecting the $316,000 difference between the adjustments to the liability and asset accounts, net of the related income tax effect. In the year ended December 31, 2003, the Company increased the abandonment liability by $386,000 for accretion of the liability and $375,000 for the additional liability associated with the completion of new wells and reduced the liability by $221,000 due to the abandonment and sale of 14 properties. Any subsequent difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability will be recognized as a gain or loss in the Company's earnings.

The pro forma accrued abandonment costs as of January 1, 2002 and January 1, 2001 were $5,933,000 and $5,577,000, respectively. Pro forma net income for the years ended December 31, 2002 and 2001, assuming SFAS No. 143 had been applied retroactively, was as follows:

	Year Ended December 31,	
	2002	2001
Net Income (loss)		
As reported	$ (950,717)	$2,234,607
Pro forma	(1,174,471)	2,010,853
Net loss applicable to common stock		
As reported	$(1,590,470)	$ (768,265)
Pro forma	(1,814,224)	(992,019)
Net income (loss) per share		
As reported, basic	$ (0.09)	$ (0.04)
Pro forma, basic	(0.10)	(0.06)
As reported, diluted	(0.09)	(0.04)
Pro forma, diluted	(0.10)	(0.06)

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133, *Accounting for Derivatives and Hedging Activities*. This statement (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, (2) clarifies when a derivative contains a financing component, and (3) amends the definition of an underlying derivative to conform to Financial Accounting Standards Board Interpretation No. 45. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, with all provisions applied prospectively. The Company adopted SFAS No. 149, effective July 1, 2003, and the adoption had no impact on its financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify an instrument that is within its scope as a liability. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and is effective at the beginning of the first interim period beginning after June 15, 2003, although in November 2003, the FASB deferred certain provisions of SFAS No. 150. As of December 31, 2003, the Company had no financial instruments within the scope of SFAS No. 150.

In July 2003, the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS

No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and it does not provide the additional disclosures for these assets. The EITF has added the discussion of oil and gas mineral leases to its agenda, which may result in a change in the recording and disclosure of oil and gas mineral leases. Should the EITF determine that oil and gas mineral leases are intangible assets, the Company would reclassify $6,409,000 and $6,563,000 as intangible undeveloped mineral interests at December 31, 2003 and 2002, respectively. In addition, a reclassification of $5,879,000 and $4,925,000 would be made as intangible developed mineral interests at December 31, 2003 and 2002, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on the Company's understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property and Equipment on the Consolidated Balance Sheet
- The Company does not believe that its net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements

In March 2004, the FASB issued an exposure draft on accounting for stock-based compensation. The exposure draft reflects the FASB's tentative conclusion that the fair value of stock options should be expensed in companies' financial statements for years ending after December 31, 2004. The exposure draft also includes the FASB's tentative decisions regarding how equity-based awards are likely to be valued, expensed, and classified. The Company will continue to monitor developments with respect to the exposure draft to determine the potential impact on its financial statements.

NOTE C—Sale of Oil and Gas Properties to Related Party

On March 12, 2002, the Company monetized a portion of the value created in its Burrwood and West Delta 83 fields by selling a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, for $12 million to Malloy Energy Company, LLC ("MEC") led by Patrick E. Malloy, III and participated in by Sheldon Appel, who was a member of the Company's Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of the Company's Board of Directors (Mr. Malloy is now Chairman of the Company's Board of Directors and Mr. Appel retired from the Board of Directors in February 2004). The sale price was determined by discounting the present value of the acquired interest in the fields' proved, probable and possible reserves using prevailing oil and gas prices. The Company retained an approximate 65% working interest in the existing production and shallow rights, and a

32.5% working interest in the deep rights after the close of the transaction. In conjunction with the sale, MEC provided a $7.7 million line of credit which reduced to $5.0 million on January 1, 2003. The credit line is subordinate to the Company's senior credit facility and can be used for acquisitions, drilling, development and general corporate purposes until December 31, 2004. MEC retains the option to convert the amount outstanding under the credit line, and/or provide cash on any unused credit into 30% of the Company's working interests in any acquisition(s) the Company makes in Louisiana prior to January 1, 2005. In the third quarter of 2003, the Company announced two Louisiana property acquisitions in which MEC has elected to participate for 30% of the Company's working interest. Since the Company has made no borrowings under the MEC credit line to date, MEC funded its share of the acquisition costs and will fund its share of the subsequent capital costs related to these acquisitions on a direct basis, rather than by converting borrowings under the credit line.

The Company recorded a non-recurring gain of approximately $2.4 million in the first quarter of 2002 as a result of the MEC sale. The proceeds were used to reduce outstanding debt under its senior credit facility.

NOTE D—Indebtedness

Indebtedness at December 31, 2003 and 2002 consists of the following:

	2003	2002
Bank Debt		
Borrowings under senior credit facility, interest at BNP Paribas prime plus 0.25% or LIBOR plus 2.0% (weighted average rate at December 31, 2003—3.73%)	$20,000,000	$18,500,000
Less current portion	—	—
Long-term debt excluding current portion	$20,000,000	$18,500,000

On November 9, 2001, the Company established a $50,000,000 senior credit facility with BNP Paribas, with an initial borrowing base of $25,000,000 and a three year term. In December 2003, the borrowing base was redetermined to be $28,000,000 and BNP Paribas and the Company agreed to extend the term of the senior credit facility for an additional two years, subject to periodic redeterminations of the borrowing base. Interest on borrowings accrues at a rate calculated, at the option of the Company, as either the BNP Paribas base rate plus 0.00% to 0.50%, or LIBOR plus 1.50%—2.50%, depending on borrowing base utilization. Interest on LIBOR-rate borrowings is due and payable on the last day of its respective interest period. Accrued interest on each base-rate borrowing is due and payable on the last day of each quarter. As extended, the senior credit facility will mature on December 29, 2006. The credit facility requires that the Company pay a 0.375% per annum commitment fee, payable in quarterly installments based on the Company's borrowing base utilization. Prior to maturity, no principal payments are required so long as the maximum borrowing base amount exceeds the amounts outstanding under the credit facility. The credit facility requires the Company to monitor tangible net worth and maintain certain financial statement ratios at certain levels. As of December 31, 2003, the Company was in compliance with all such requirements. Substantially all the Company's assets are pledged to secure the senior credit facility.

Interest paid during 2003, 2002 and 2001 amounted to $860,150, $639,147 and $849,725, respectively.

NOTE E—Income (Loss) Per Share

Net income (loss) was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2003, 2002 and 2001. The following table reconciles the weighted average shares outstanding used for these computations.

	Year ended December 31,		
	2003	2002	2001
Basic Method	18,064,329	17,908,182	17,351,375
Stock Warrants	2,364,049	—	—
Stock Options	53,422	—	—
Dilutive Method	20,481,800	17,908,182	17,351,375

The computation of earnings per share for the year ended December 31, 2003 considered exercisable stock warrants and stock options under the treasury stock method to the extent that the exercise of such securities would have been dilutive, however, the computation of earnings per share for the years ended December 31, 2002 and 2001 did not consider exercisable stock warrants and stock options as the effect would have been antidilutive (the excluded stock warrants amounted to 3,137,408 shares for the years ended December 31, 2002 and 2001 and the excluded stock options amounted to 1,536,052 shares and 1,465,062 shares for the years ended December 31, 2002 and 2001, respectively). The computation of earnings per share for each of the three years ended December 31, 2003 did not include the effects of the Company's convertible preferred stock because the effect would have been antidilutive.

See Note H for discussion of a cashless exercise of 319,387 stock warrants in January 2004 which resulted in the issuance of 252,033 shares of common stock.

NOTE F—Income Taxes

Income tax expense (benefit) for the years ending December 31, 2003, 2002 and 2001 consists of:

	Current	Deferred	Total
Year ended December 31, 2003			
U.S. Federal	$—	$2,121,080	$2,121,080
State	—	—	—
	$—	$2,121,080	$2,121,080
Year ended December 31, 2002			
U.S. Federal	$—	$ (506,666)	$ (506,666)
State	—	—	—
	$—	$ (506,666)	$ (506,666)
Year ended December 31, 2001			
U.S. Federal	$—	$1,211,033	$1,211,033
State	—	—	—
	$—	$1,211,033	$1,211,033

The following is a reconciliation of the U.S. statutory income tax rate at 35% to the Company's income (loss) before income taxes for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
U.S. statutory income tax	$2,115,355	$(510,084)	$1,205,974
Nondeductible expenses	5,725	3,418	5,059
	$2,121,080	$(506,666)	$1,211,033

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2003 and 2002 are presented below.

	2003	2002
Deferred tax assets:		
Differences between book and tax basis of:		
Operating loss carryforwards	$ 14,045,530	$ 14,234,869
Statutory depletion carryforward	7,034,566	7,034,566
AMT Tax credit carryforward	1,399,890	1,399,890
Asset related to hedging activities	537,383	365,666
Contingent liabilities	45,566	132,348
Other	347,676	280,548
Total gross deferred tax assets	23,410,611	23,447,887
Less valuation allowance	(17,480,486)	(17,641,358)
Net deferred tax asset	5,930,125	5,806,529
Deferred tax assets:		
Differences between book and tax basis of:		
Property and equipment	(6,134,590)	(4,172,173)
Total gross deferred liability	(6,134,590)	(4,172,173)
Net deferred tax asset (liability)	$ (204,465)	$ 1,634,356

The valuation allowance for deferred tax assets decreased $160,872 and increased $640,885 for the years ended December 31, 2003 and 2002, respectively. The changes in both years are primarily the result of changes in deferred tax assets. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based primarily upon the level of projections for future taxable income and the reversal of future taxable temporary differences over the periods which the deferred tax assets are deductible, management believes it is more likely than not the Company will realize the benefits of these deductible differences, net of the existing valuation allowance at December 31, 2003. The amount of the deferred tax assets considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

The following table summarizes the amounts and expiration dates of operating loss carryforwards:

Operating loss carryforwards	
Expires	**Amounts**
2006	$ 3,595,760
2007	8,860,622
2008	4,285,746
2009	3,247,494
2010	6,450,859
2011	600,706
2012	1,939,496
2018	4,530,029
2019	2,546,445
2020	372,409
2021	1,750
2022	3,698,768
	$40,130,084

An ownership change in accordance with Internal Revenue Code (IRC) (S)382, occurred in August 1995 and again in August 2000. The net operating losses (NOLs) generated prior to August 1995 are subject to an annual IRC (S)382 limitation of $1,682,797. The IRC (S)382 annual limitation for the ownership change in August 2000 is $3,647,700. The latter IRC (S)382 ownership change limitation is a cumulative limitation and does not eliminate or increase the limitation on the pre-August 1995 NOLs. The NOLs generated after August 1995 and prior to August 2000, are subject to an annual limitation of $3,647,700 less the annual amount utilized for pre-August 1995 NOLs. It should be noted that the same IRC (S)382 limitations apply to the alternative minimum tax net operating loss carryforwards, depletion carryforwards, and alternative minimum tax credit carryforwards. The minimum tax credit carryforward (MTC) of $1,399,890 as of December 31, 2003, will not begin to be utilized until after the available NOLs have been utilized or expired and when regular tax exceeds the current year alternative minimum tax. The unused annual IRC (S)382 limitations can be carried over to subsequent years.

NOTE G—Production Payment Obligation

A production payment was entered into by the Company to assist in the financing of the Lafitte field acquisition in September 1999. The original amount of the production payment obligation was $2,940,000, which was recorded as a production payment liability of $2,228,000 after a discount to reflect an effective rate of interest of 11.25%. At December 31, 2003 the remaining principal amount was $846,000 and the recorded liability was $610,000. Under the terms of the production payment the Company must make monthly cash payments which approximate 10% of the Company's 49% working interest share of the monthly gross oil and gas revenue of the Lafitte field.

The Company's estimate as of December 31, 2003, based on projected production volumes and prices and expected discount amortization, is that projected payments could liquidate the liability in the year ended December 31, 2004, however, the Company has not reflected such a current classification due to the inherent imprecision in its production projections as well as the fact that the source of repayment is a non-current asset.

NOTE H—Stockholders' Equity

On February 1, 2001, the Company completed a public offering of 3,000,000 shares of its common stock at $5.00 per share resulting in net proceeds of approximately $13.1 million to the Company. The Company used the proceeds from the offering along with other available funds to reduce outstanding debt under its senior credit facility by approximately $13.7 million.

Common Stock—At December 31, 2003, a total of 3,633,942 unissued shares of Goodrich common stock were reserved for the following: (a) 3,070,879 shares for the exercise of stock warrants; (b) 232,813 shares for the exercise of stock options; and (c) 330,250 shares for the conversion of Series A convertible preferred stock. The stock warrants were issued in connection with a September 1999 private placement of convertible notes and subsidiary securities at exercise prices ranging from $0.9375 to $1.50 per share and expire in September 2006. Each warrant is exercisable into one share of common stock upon payment of the exercise price, however, the holders of the stock warrants may, in certain circumstances, elect a cashless exercise whereby additional "in the money" warrants can be tendered to cover the exercise price of the warrants. In January 2004, the holders of 319,387 warrants elected a cashless exercise of such warrants resulting in the issuance of 252,033 shares of the Company's common stock.

Preferred Stock—The Series A convertible preferred stock has a par value of $1.00 per share with a liquidation preference of $10.00 per share, and is convertible at the option of the holder at any time, unless earlier redeemed, into shares of common stock of the Company at an initial conversion rate of .417 shares of common stock per share of Series A preferred. The Series A preferred stock also will automatically convert to common stock if the closing price for the Series A preferred stock exceeds $15.00 per share for ten consecutive trading days. The Series A preferred stock is redeemable in whole or in part, at $12.00 per share, plus accrued and unpaid dividends. Dividends on the Series A preferred stock accrue at an annual rate of 8% and are cumulative.

The Company issued 750,000 shares of Series B convertible preferred stock in connection with its acquisition of the La/Cal II properties on January 31, 1997. The Series B convertible preferred stock had a par value of $1.00 per share with a liquidation preference of $10.00 per share and ranked junior to the Series A preferred stock. The shares of Series B preferred stock were convertible at the option of the holder at any time, unless earlier redeemed, into shares of common stock of the Company at the conversion rate of 1.12 shares of common stock per share of Series B preferred stock. The Series B preferred stock was redeemable by the Company prior to January 31, 2001 at $10.00 per share. Dividends on the Series B preferred stock accrued at an annual rate of 8.25% and were cumulative.

In January 2001, the Company reached an agreement with all of the holders of its Series B preferred stock to exchange each share of Series B for 1.8 shares of its common stock. Concurrent with the closing of its public offering in February 2001, the Company exchanged all 660,839 shares of its Series B preferred stock into 1,189,510 shares of common stock. In connection with the conversion of the Series B preferred stock, a conversion premium in the amount of $2,377,000 was recorded to reflect the excess of the 1.8:1.0 conversion factor over the terms of the original preferred stock issuance. This one-time, non-cash charge was reflected as a preferred stock dividend to arrive at net income applicable to common stock and did not have an affect on total stockholders' equity.

Stock Option and Incentive Programs—Goodrich currently has two plans, which provide for stock option and other incentive awards for the Company's key employees, consultants and directors. The Goodrich Petroleum Corporation 1995 Stock Option Plan allows the Board of Directors to grant stock options, restricted stock awards, stock appreciation rights, long-term incentive awards and phantom stock awards, or any combination thereof, to key employees and consultants. The Goodrich Petroleum Corporation 1997 Director Compensation Plan provides for the grant of stock and options to each director who is not and has never been an employee of the Company. Additionally, the Company assumed certain outstanding stock options of Patrick as a result of the business combination in 1995.

The Goodrich plans authorize grants of options to purchase up to a combined total of 2,150,000 shares of authorized but unissued common stock. Stock options are generally granted with an exercise price equal to the stock's fair market value at the date of grant, and all employee stock options granted under the 1995 Stock Option Plan generally have ten year terms and three year pro rata vesting.

There were no employee stock options granted in the year ended December 31, 2003. The per share weighted average fair value of stock options granted during the years ended December 31, 2002 and 2001 were $2.43 and $2.63, respectively, on the date of grant using the Black Scholes option-pricing model with the following weighted-average assumptions: (i) 2002—expected dividend yield 0%, risk-free interest rate of 6%, volatility of 29%, and an expected life of 5 years; (ii) 2001—expected dividend yield 0%, risk-free interest rate of 6%, volatility of 35%, and an expected life of 6 years.

In February 2003, the Company issued 125,157 shares of its common stock to the holders of 1,016,500 outstanding stock options in exchange for the cancellation of such options (at the time of cancellation, the options were antidilutive). At the same time, the Company agreed to issue 150,000 restricted shares of its common stock, with a three year vesting period, to its employees under the Company's restricted stock awards plan. The Company recorded a non-cash charge to earnings in February 2003 in the amount of $403,000 related to the issuance of shares in lieu of cancelled options. The granting of the restricted stock awards in February 2003 resulted in a charge to a contra equity account and a credit to additional paid-in capital in the amount of $483,000 related to the value of such awards. The contra equity account is being amortized to earnings as periodic non-cash charges to general and administrative expenses over the three year vesting period of the restricted stock awards. In July and October 2003, the Company granted an additional 11,500 restricted share awards to its employees and recorded a charge to the contra equity account for the value of such shares in the amount of $54,000. For the year ended December 31, 2003, the Company recorded non-cash charges to earnings for the amortization of the aggregate awards of 161,500 restricted shares in the amount of $155,000. The Company will be required to record recurring non-cash charges to earnings of approximately $43,000 per quarter, through the first quarter of 2006, related to the periodic vesting of the restricted stock.

In February 2004, the Company agreed to issue an additional 164,300 restricted shares of its common stock, with a three year vesting period, to its employees under the Company's restricted stock awards plan. At the time of this grant, the Company recorded a charge to a contra equity account and a credit to additional paid-in capital in the amount of $1,134,000 related to the value of such awards. The contra equity account is being amortized to earnings as periodic non-cash charges to general and administrative expenses over the three year vesting period of the restricted stock awards. Accordingly, the Company will be required to record incremental recurring non-cash charges to earnings of approximately $94,500 per quarter, through the first quarter of 2007, related to the periodic vesting of the February 2004 restricted stock awards.

Stock option transactions during 2003, 2002 and 2001 were as follows:

	Number of Options	Weighted Average Exercise Price	Range of Exercise Price	Weighted Average Remaining Contractual Life
Outstanding January 1, 2001	762,938		$0.75 to $24.00	8.9 yrs
Granted—1995 Stock Option Plan	710,000	5.79		
Granted—1997 Director Compensation Plan	24,000	5.85		
Exercised—1995 Stock Option Plan	(7,500)	1.54		
Expiration of Options	(24,376)	7.67		
Outstanding December 31, 2001	1,465,062		$0.75 to $18.00	8.7 yrs
Granted—1995 Stock Option Plan	63,000	3.72		
Granted—1997 Director Compensation Plan	24,000	4.11		
Exercised—1995 Stock Option Plan	(10,677)	2.63		
Expiration of Options	(5,333)	2.63		
Outstanding December 31, 2002	1,536,052		$0.75 to $18.00	7.8 yrs
Granted—1997 Director Compensation Plan	20,000	4.85		
Cancelled in exchange for common stock	(1,016,500)	5.22		
Exercised—1995 Stock Option Plan	(24,000)	2.63		
Expiration of Options	(282,739)	5.38		
Outstanding December 31, 2003	232,813		$0.75 to $5.85	7.7 yrs
Exercisable December 31, 2001	349,063	5.21		
Exercisable December 31, 2002	764,917	5.32		
Exercisable December 31, 2003	190,813	2.97		

NOTE I—Hedging Activities

Commodity Hedging Activity

The Company enters into swap contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of its production. The Company considers these to be hedging activities and, as such, monthly settlements on these contracts are reflected in its crude oil and natural gas sales. The Company's strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to hedge between 30% and 70% of its production. As of December, 31, 2003, all of the commodity hedges utilized by the Company were in the form of fixed price swaps, where the Company receives a fixed price and pays a floating price based on NYMEX quoted prices. Hedge ineffectiveness results from differences in the NYMEX contract terms and the physical location, grade and quality of the Company's oil and gas production. As of December 31, 2003, the Company's open forward position on its outstanding commodity hedging contracts, all of which were with BNP Paribas, was as follows:

Crude Oil

700 barrels of oil per day "swap" at $28.59 for January 2004 through June 2004; and
300 barrels of oil per day "swap" at $30.92 for January 2004 through June 2004; and
700 barrels of oil per day "swap" at $28.20 for July 2004 through December 2004

Natural Gas

3,000 MMBtu per day "swap" at $5.00 for January 2004 through December 2004

The hedging contracts summarized above are based on floating NYMEX contract prices and fall within the Company's targeted range of 30% to 70% of its estimated net oil and gas production volumes for the applicable periods of 2004. The fair value of the crude oil and natural gas hedging contracts in place at December 31, 2003 resulted in a liability of $1,257,000. As of December 31, 2003, $817,000 (net of $440,000 in income taxes) of deferred losses on derivative instruments accumulated in other comprehensive income are expected to be reclassified into earnings during the next twelve months. In the year ended December 31, 2003, $1,905,000 of previously deferred losses (net of $1,026,000 in income taxes) was reclassified from accumulated other comprehensive income to oil and gas sales as the cash flow of the hedged items was recognized. For the year ended December 31, 2003, the Company's earnings were not significantly affected by cash flow hedging ineffectiveness arising from the crude oil and gas hedging contracts. Subsequent to December 31, 2003, the Company entered into the following crude oil and natural gas hedging contracts with BNP Paribas:

300 barrels of oil per day "swap" at $30.25 for July 2004 through December 2004
3,000 MMBtu per day "swap" at $5.41 for April 2004 through October 2004
3,000 MMBtu per day "swap" at $6.20 for November 2004 through December 2004
6,000 MMBtu per day "swap" at $6.27 for January 2005 through March 2005

Price Fluctuations and the Volatile Nature of Markets

Despite the measures taken by the Company to attempt to control price risk, the Company remains subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond the Company's control. Domestic crude oil and gas prices could have a material adverse effect on the Company's financial position, results of operations and quantities of reserves recoverable on an economic basis.

Debt and Debt-Related Derivatives

In February 2003, the Company entered into three separate interest rate swaps with BNP Paribas, covering a three year period, which are accounted for as cash flow hedges of future variable rate interest payments on the Company's floating senior secured credit facility. The first interest rate swap, which has an effective date of February 26, 2003 and a maturity date of February 26, 2004 is for $18,000,000 with a LIBOR swap rate of 1.53%. The second interest rate swap, which has an effective date of February 26, 2004 and a maturity date of November 8, 2004, is for $18,000,000 with a LIBOR swap rate of 2.25%. The third interest rate swap, which has an effective date of November 8, 2004 and a maturity date of February 26, 2006, is for $18,000,000 with a LIBOR swap rate of 3.46%. The fair value of the interest rate swap contracts in place at December 31, 2003, resulted in a liability of $278,000. As of December 31, 2003, $81,000 (net of $44,000 in income taxes) of deferred losses on derivative instruments accumulated in other comprehensive income are expected to be reclassified into earnings during the next twelve months. In the year ended December 31, 2003, $13,000 of previously deferred losses (net of $7,000 in income taxes) was reclassified from accumulated other comprehensive income to interest expense as the cash flow of the hedged items was recognized. For the year ended December 31, 2003, the Company's earnings were not significantly affected by cash flow hedging ineffectiveness of interest rates. Subsequent to December 31, 2003, the Company entered into a fourth interest rate swap contract with BNP Paribas, which has an effective date of February 26, 2006 and a maturity date of February 26, 2007, for $23,000,000 with a LIBOR swap rate of 4.08%.

NOTE J—Fair Value of Financial Instruments

The following presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2003 and 2002.

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial instruments—				
Long-term debt (including current maturities)	$20,000,000	$20,000,000	$18,500,000	$18,500,000
Production payment liability	$ 609,675	$ 623,375	$ 978,321	$ 978,321
Oil and gas derivative assets (liabilities)				
Oil	$ (634,747)	$ (634,747)	$ (185,759)	$ (185,759)
Gas	$ (622,695)	$ (622,695)	$ (922,669)	$ (922,669)
Interest rate derivative assets (liabilities)	$ (277,938)	$ (277,938)	$ —	$ —

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and cash equivalents, accounts receivable, restricted cash, accounts payables and accrued liabilities: The carrying amounts approximate fair value because of the short maturity of those instruments. Therefore, these instruments were not presented in the table above.

Long term debt and other noncurrent liabilities: The fair value is estimated using the discounted cash flow method based on the Company's borrowing rates for similar types of financing arrangements.

Oil and gas derivatives: The fair value is calculated based on the discounted cash flow expected to be received or paid on the derivative utilizing future posted market prices of the underlying product.

Interest rate derivatives: The fair value is calculated based on the discounted cash flow expected to be received or paid on the derivative utilizing estimated market prices for interest rate futures.

NOTE K—Concentrations of Credit Risk and Significant Customers

Due to the nature of the industry the Company sells its oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from these sources as a percent of total revenues for the periods presented were as follows:

	Year Ended December 31,		
	2003	2002	2001
Louis Dreyfus Corporation	47%	—	—
Texon, LP	25%	—	—
Reliant Energy	—	45%	56%
Conoco Phillips	5%	17%	—
Shell Trading	—	17%	—
Genesis Crude Oil, L.P.	—	5%	22%

Effective January 1, 2003, the Company contracted with Louis Dreyfus Corporation as its major gas purchaser in lieu of Reliant Energy.

NOTE L—Commitments and Contingencies

The U.S. Environmental Protection Agency ("EPA") has identified the Company as a potentially responsible party ("PRP") for the cost of clean-up of "hazardous substances" at an oil field waste disposal site in Vermilion Parish, Louisiana. The Company estimates that the remaining cost of long-term clean-up of the site will be approximately $3.5 million, with the Company's percentage of responsibility estimated to be approximately 3.05%.

As of December 31, 2003, the Company had paid $321,000 in costs related to this matter and accrued $122,500 for the remaining liability. These costs have not been discounted to their present value. The EPA and the PRPs will continue to evaluate the site and revise estimates for the long-term clean-up of the site. There can be no assurance that the cost of clean-up and the Company's percentage responsibility will not be higher than currently estimated. In addition, under the federal environmental laws, the liability costs for the clean-up of the site is joint and several among all PRPs. Therefore, the ultimate cost of the clean-up to the Company could be significantly higher than the amount presently estimated or accrued for this liability.

In connection with the acquisition of its Burrwood and West Delta 83 fields, the Company secured a performance bond and established an escrow account to be used for the payment of obligations associated with the plugging and abandonment of the wells, salvage and removal of platforms and related equipment, and the site restoration of the fields. Required escrowed outlays included an initial cash payment of $750,000 and monthly cash payments of $70,000 beginning June 1, 2000 and continuing until June 1, 2005. The escrow agreement was amended in the fourth quarter of 2001 to suspend monthly cash payments and cap the escrow account at its current balance of $2,039,000. In addition, as part of the purchase agreement, the Company agreed to shoot a 3-D seismic survey over the fields which was completed in the fourth quarter of 2001. The cost of the seismic survey was approximately $2,500,000.

On February 8, 2000, the Company commenced a suit against the operator and joint owner of the Lafitte field, alleging certain items of misconduct and violations of the agreements associated primarily with the joint acquisition of and unfettered access to a license to 3-D seismic data over the field. The operator counter-claimed against Goodrich on the grounds that Goodrich was obligated to post a bond to secure the plugging and abandonment obligations in the field. On November 1, 2002 the 125th Judicial District Court of Harris County, Texas, ruled in favor of the Company stating (1) The Sale and Assignment between the Company and the operator assigned the same rights to the 3-D seismic data that the operator had pursuant to the operator's data use license agreement from Texaco Exploration and Production, Inc. ("TEPI"); and (2) Also pursuant to the terms of the Sale and Assignment, Goodrich is required to post 49% of the bond liability to TEPI at such time that TEPI requests it. A jury trial commenced in September 2003. On October 29, 2003, the jury found the operator and joint owner to be in breach of the Sale and Assignment and awarded a wholly-owned subsidiary of the Company damages in the amount of $537,500. The jury's verdict has not yet been certified by the trial judge nor has the court made a determination on the Company's claim for reimbursement of legal fees and other expenses related to the case. The timing of the outcome of these rulings is presently uncertain, however, the Company does not anticipate that the rulings will ultimately have a significant adverse impact on the Company's operations or financial position.

The Company is party to additional lawsuits arising in the normal course of business. The Company intends to defend these actions vigorously and believes, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to its financial position or results of operations.

NOTE M—Natural Gas and Crude Oil Cost Data

The table below reflects the Company's capitalized costs related to oil and gas activities at December 31, 2003, and 2002. As a result of the restatement of the Company's 2002 and 2001 financial statements (see Note A), the table reflects reallocations of the purchase price of three oil and gas property acquisitions completed prior to January 1, 2001, based upon analyses of contemporaneous documentation from the time of the acquisitions.

	December 31, 2003	December 31, 2002 (Restated)
Proved properties	$106,394,711	$ 94,453,659
Unproved properties	12,287,598	11,517,509
	118,682,309	105,971,168
Less accumulated depreciation and depletion	(43,807,020)	(41,941,254)
Net oil and gas properties	$ 74,875,289	$ 64,029,914

As of December 31, 2003, the net book value of unproved properties was $6,408,912. As of December 31, 2002, assuming that FAS 143 had been applied retroactively, the pro forma gross cost of proved and unproved properties would have been $106,001,085 and the pro forma net cost would have been $64,054,190. The following table reflects certain data with respect to cost incurred in natural gas and oil property acquisitions, exploration and development activities:

	Year ended December 31 2003	2002	2001
Property acquisition			
Proved	$ —	$ —	$ 175,110
Unproved	600,839	—	2,186,111
Asset retirement costs (1)	375,313	—	—
Exploration	2,248,802	1,128,855	4,174,348
Development	17,723,628	7,843,730	28,972,446
	$20,948,582	$8,972,585	$35,508,015

(1) Excludes pro forma asset retirement costs, assuming SFAS No. 143 had been applied retroactively, of $29,917 and $122,262 in 2002 and 2001, respectively.

NOTE N—Related Party Transactions

On June 1, 2001 the Company entered into a consulting agreement with Patrick E. Malloy, III, a member of the Company's Board of Directors, under which Mr. Malloy provided the Company advice on hedging and financial matters. The contract, which expired in May 2003, paid Mr. Malloy $120,000 per year. The Company paid Mr. Malloy $50,000 in 2003, $120,000 in 2002 and $70,000 in 2001.

On March 12, 2002, the Company completed the sale of a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, in its Burrwood and West Delta 83 fields for $12 million to Malloy Energy Company, LLC ("MEC"), led by Patrick E. Malloy, III and participated in by Sheldon Appel, who was a member of the Company's Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of the Company's Board of Directors (Mr. Malloy is now Chairman of the Company's Board of Directors and Mr. Appel retired from the Board of Directors in February 2004). See Note C for further information regarding the sale.

Subsequent to the acquisition of a 30% working interest in the Burrwood and West Delta 83 fields in March 2002, MEC acquired an approximate 30% working interest in two other fields operated by the Company in late 2003. In accordance with industry standard joint operating agreements, the Company bills MEC for its share of the capital and operating costs of the three fields on a monthly basis. As of December 31, 2003 and 2002, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $1,129,000 and $1,036,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by MEC to the Company in the month subsequent to billing and the affiliate is current on payment of its billings.

The Company also serves as the operator for a number of other oil and gas wells owned by an affiliate of MEC in which the Company owns a 7% after payout working interest. In accordance with industry standard joint operating agreements, the Company bills the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2003 and 2002, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were $535,000 and $68,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to the Company in the month subsequent to billing and the affiliate is current on payment of its billings.

The Company acted as agent for certain stockholders to facilitate a stock purchase agreement and, in that capacity, the Company temporarily received funds totaling $3,886,988 from the purchasing stockholders, which are reflected on the Company's December 31, 2003 balance sheet in both cash and current liabilities. In accordance with the terms of the stock purchase agreement, the Company transferred the funds to the selling stockholders in January 2004 upon the sale of the shares. A portion of the shares of common stock sold by the selling stockholders resulted from the cashless exercise of warrants (see Note H, "Common Stock").

NOTE O—Supplemental Oil and Gas Reserve Information (Unaudited)

The supplemental oil and gas reserve information that follows is presented in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The schedules provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information follows concerning the schedules.

Schedules 1 and 2—Estimated Net Proved Oil and Gas Reserves

Substantially all of the Company's reserve information related to crude oil, condensate, and natural gas liquids and natural gas was compiled based on evaluations performed by Coutret and Associates, Inc. All of the subject reserves are located in the continental United States.

Many assumptions and judgmental decisions are required to estimate reserves. Quantities reported are considered reasonable but are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other factors.

Regulations published by the Securities and Exchange Commission define proved reserves as those volumes of crude oil, condensate, and natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those volumes expected to be recovered as a result of making additional investments by drilling new wells on acreage offsetting productive units or recompleting existing wells.

Schedule 3—Standardized Measure of Discounted Future Net Cash Flows to Proved Oil and Gas Reserves

SFAS No. 69 requires calculation of future net cash flows using a ten percent annual discount factor and year end prices, costs, and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

The calculated value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs, and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 3 also presents a summary of the principal reasons for change in the standard measure of discounted future net cash flows for each of the three years in the period ended December 31, 2003.

Schedule 1—Estimated Net Proved Gas Reserves (Mcf)

	Year ended December 31		
	2003	2002	2001
Proved:			
Balance, beginning of period	29,069,550	33,956,250	29,510,679
Revisions of previous estimates	648,283	29,807	6,070
Purchase of minerals in place	—	—	1,527,172
Extensions, discoveries, and other additions	6,130,098	3,848,920	6,735,556
Production	(3,361,041)	(2,477,790)	(3,823,227)
Sale of minerals in place	(1,583,500)	(6,287,637)	—
Balance, end of period	30,903,390	29,069,550	33,956,250
Proved developed:			
Beginning of period	15,203,255	16,692,390	22,251,970
End of period	23,429,440	15,203,255	16,692,390

Schedule 2—Estimated Net Proved Oil Reserves (Barrels)

	Year ended December 31		
	2003	2002	2001
Proved:			
Balance, beginning of period	7,441,340	8,750,420	6,789,358
Revisions of previous estimates	54,419	28,476	(5,602)
Purchase of minerals in place	—	—	30,829
Extensions, discoveries, and other additions	794,095	120,970	2,517,515
Production	(484,444)	(451,564)	(581,680)
Sale of minerals in place	—	(1,006,962)	—
Balance, end of period	7,805,410	7,441,340	8,750,420
Proved developed:			
Beginning of period	2,556,670	3,399,610	3,196,330
End of period	3,600,980	2,556,670	3,399,610

The following table summarizes the Company's combined oil and gas reserve information on a Mcf equivalent basis. Estimates of oil reserves were converted using a conversion ratio of 1.0/6.0 Mcf.

	Year ended December 31		
	2003	2002	2001
Estimated Net Proved Reserves (Mcfe):			
Total Proved	77,735,850	73,717,590	86,458,770
Proved Developed	45,035,320	30,543,570	37,090,050

Schedule 3—Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

	Year ended December 31		
	2003	2002	2001
		(in thousands)	
Future cash inflows	$410,851	$313,883	$220,367
Production taxes	(52,615)	(54,345)	(59,906)
Development costs (1)	(33,180)	(28,953)	(35,673)
Future income tax expense	(77,855)	(44,292)	(8,972)
Future net cash flows	247,201	186,293	115,816
10% annual discount for estimated timing of cash flows	(83,227)	(62,031)	(42,694)
Standardized measure of discounted future net cash flows	$163,974	$124,262	$ 73,122
Average year end prices:			
Natural gas (per MCF)	$ 6.42	$ 4.35	$ 2.51
Crude oil (per BBL)	$ 31.75	$ 28.80	$ 17.91

(1) Includes asset retirement obligation of $6,905,000 in 2003.

The following are the principal sources of change in the standardized measure of discounted net cash flows for the years shown:

	Year ended December 31		
	2003	2002	2001
	(in thousands)		
Net changes in prices and production costs related to future production	$ 47,406	$ 84,143	$(209,020)
Sales and transfers of oil and gas produced, net of production costs	(24,378)	(9,548)	(21,100)
Net change due to revisions in quantity estimates	2,693	413	(26)
Net change due to extensions, discoveries and improved recovery	30,081	9,393	19,930
Net change due to purchase and sales of minerals-in-place	(4,373)	(25,314)	1,562
Development costs incurred during the period	(4,227)	6,720	11,767
Net change in income taxes	(23,136)	(21,738)	64,557
Accretion of discount	15,136	7,889	25,011
Change in production rates (timing) and other	510	(818)	661
	$ 39,712	$ 51,140	$(106,658)

GOODRICH PETROLEUM CORPORATION

Consolidated Quarterly Income Information
(Unaudited)

	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
2003								
Revenues	$7,078,480	$7,078,480	$7,882,740	$ 7,882,740	$7,994,758	$7,994,758	$9,741,714	
Cost and Expenses	6,192,741	6,676,825	5,802,190	6,257,590	5,636,100	6,118,619	7,534,672	
Gain (loss) on sale of assets	(21,082)	(21,082)	(216,185)	(216,185)	8,438	8,438	162,713	
Income taxes	302,627	133,198	652,028	492,638	828,483	659,601	835,643	
Cumulative effect of accounting change	(205,293)	(205,293)	—	—	—	—	—	
Net income (loss)	356,737	42,082	1,212,337	916,327	1,538,613	1,224,976	1,534,112	
Preferred Stock dividends	158,366	158,366	158,366	158,366	158,366	158,366	158,365	
Income (loss) applicable to Common Stock	198,371	(116,284)	1,053,971	757,961	1,380,247	1,066,610	1,375,747	
Basic Income (loss) per average Common share	0.01	(0.01)	0.06	0.04	0.08	0.06	0.08	
Diluted Income (loss) per average Common share	0.01	(0.01)	0.05	0.04	0.07	0.05	0.07	
2002								
Revenues	$4,699,682	$4,699,682	$4,308,024	$ 4,308,024	$4,258,020	$4,258,020	$5,834,203	$5,834,203
Cost and Expenses	5,594,856	6,010,423	5,596,170	6,003,964	4,796,331	5,205,752	5,810,119	6,278,235
Gain (loss) on sale of assets	2,836,501	2,836,501	87,700	87,700	(80,393)	(80,393)	97,254	97,254
Income taxes	679,464	534,016	(420,156)	(562,884)	(216,546)	(359,843)	45,886	(117,955)
Net income (loss)	1,261,863	991,745	(780,290)	(1,045,356)	(402,158)	(668,282)	75,452	(228,824)
Preferred Stock dividends	154,798	154,798	168,223	168,223	158,366	158,366	158,366	158,366
Income (loss) applicable to Common Stock	1,107,065	836,947	(948,513)	(1,213,579)	(560,524)	(826,648)	(82,914)	(387,190)
Basic Income (loss) per average Common share	0.06	0.05	(0.05)	(0.07)	(0.03)	(0.05)	0.00	(0.02)
Diluted Income (loss) per average Common share	0.05	0.04	(0.05)	(0.07)	(0.03)	(0.05)	0.00	(0.02)

As indicated in note A, in the course of preparing its 2003 year-end financial statements, the Company discovered a systematic error in the calculations of its non-cash depletion, depreciation and amortization expense since 1997. The above amounts reflect restatement of the Company's previously reported quarterly financial results for all four quarters of 2002 and the first three quarters of 2003.

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

None

Item 9A. ***Controls and Procedures.***

The Company, under the direction of its chief executive officer and chief financial officer, has established controls and procedures to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the company's financial reports and to other members of senior management and the Board of Directors.

Except as discussed below, based on their evaluation as of December 31, 2003, the chief executive officer and chief financial officer of Goodrich Petroleum Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2003 to ensure that the information required to be disclosed by Goodrich Petroleum Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

In the course of preparing its 2003 year-end financial statements, the Company discovered a systematic error in the calculations of its non-cash depletion, depreciation and amortization expense since 1997. Essentially, the Company had been allocating the acquisition and development costs of its oil and gas properties over total proved reserves in each field rather than segregating the costs between those costs to be allocated over proved developed reserves versus those costs to be allocated over total proved reserves. Accordingly, the Company has restated its previously reported depletion, depreciation and amortization expense in its audited financial statements for the years ended December 31, 2001 and 2002 and in its unaudited quarterly income information for the four quarters of 2002 and the first three quarters of 2003. The Company's independent accountants, KPMG LLP, have provided a letter to the Company's Audit Committee indicating the Company did not have internal controls in place that would have detected this systematic error. The error has been corrected through restatement of the prior period financial statements. Because the system of internal controls failed to detect the error, which had a material effect on the financial statements and resulted in the restatement of the prior period financial statements, the Company's lack of internal controls in this area is deemed to be a material weakness. In conjunction with its Audit Committee, the Company has taken steps to address the internal control deficiency.

Except for any changes in processes and procedures related to the matter noted above, there were no significant changes in the Company's internal controls or in other factors that could significantly affect those controls subsequent to the date of their most recent evaluation.

PART III

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

The Company's executive officers and directors and their ages and positions as of April 9, 2004 are as follows:

Name	Age	Position
Patrick E. Malloy, III	61	Chairman of the Board of Directors
Walter G. "Gil" Goodrich	45	Vice Chairman, Chief Executive Officer and Director
Robert C. Turnham, Jr.	46	President and Chief Operating Officer
Mark E. Ferchau	50	Senior Vice President, Engineering and Operations
Douglas B. Selvius	45	Senior Vice President, Exploration
D. Hughes Watler, Jr.	55	Senior Vice President, Chief Financial Officer and Treasurer
Henry Goodrich	73	Chairman—Emeritus and Director
Josiah T. Austin	56	Director
John T. Callaghan	49	Director
Geraldine A. Ferraro	68	Director
Michael J. Perdue	49	Director
Arthur A. Seeligson	45	Director
Gene Washington	57	Director
Steven A. Webster	52	Director

Patrick E. Malloy, III became Chairman of the Board of Directors in February 2003. He has been President and Chief Executive Officer of Malloy Enterprises, Inc., a real estate and investment holding company, and Malloy Real Estate, Inc. since 1973. In addition, Mr. Malloy served as a director of North Fork Bancorp (NYSE) from 1998 to 2002 and was Chairman of the Board of New York Bancorp (NYSE) from 1991 to 1998. He joined the Company's Board in May 2000.

Walter G. "Gil" Goodrich became Vice Chairman of the Board of Directors in February 2003. He has served as the Company's Chief Executive Officer since August 1995. Mr. Goodrich was Goodrich Oil Company's Vice President of Exploration from 1985 to 1989 and its President from 1989 to August 1995. He joined Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company, as an exploration geologist in 1980. Gil Goodrich is the son of Henry Goodrich. He has served as one of the Company's directors since August 1995.

Robert C. Turnham, Jr. has served as the Company's Chief Operating Officer since August 1995 and became President and Chief Operating Officer in February 2003. He has held various positions in the oil and natural gas business since 1981. From 1981 to 1984, Mr. Turnham served as a financial analyst for Pennzoil. In 1984, he formed Turnham Interests, Inc. to pursue oil and natural gas investment opportunities. From 1993 to August 1995, he was a partner in and served as President of Liberty Production Company, an oil and natural gas exploration and production company.

Mark E. Ferchau has been the Company's Senior Vice President, Engineering and Operations since February 2003, after initially joining the Company as Vice President, Engineering and Operations in September 2001. Mr. Ferchau previously served as Production Manager for Forcenergy Inc from 1997 to 2001 and as Vice President, Engineering of Convest Energy Corporation from 1993 to 1997. Prior thereto, Mr. Ferchau held various positions with Wagner & Brown, Ltd. and other independent oil and gas companies.

Douglas B. Selvius has been the Company's Senior Vice President, Exploration since February 2003, after initially joining the Company as Vice President and Exploration Manager in April 2001. Prior to that time, Mr. Selvius served as Division Geologist for IP Petroleum, a subsidiary of International Paper Company, where he led IP's onshore and offshore exploration efforts from 1993 until 2001. From 1982 through 1988, Mr. Selvius was a Senior Geologist for Tenneco Oil Company, and from 1989 until 1993 he served as Senior Geologist and Gulf Coast Project Leader for BHP Petroleum (Americas). Mr. Selvius will be terminating his employment with the Company, effective April 30, 2004.

D. Hughes Watler, Jr. joined the Company as Senior Vice President, Chief Financial Officer and Treasurer in March 2003. Mr. Watler is a former partner of Price Waterhouse LLP in their Houston and Tulsa offices, and was the Chief Financial Officer of Texoil, Inc, a public exploration & production company from 1992 to 1995, as well as XPRONET Inc., a private international oil & gas exploration company from 1998 to 2002. From 1995 to 1998, Mr. Watler served as the Corporate Controller for TPC Corporation, a NYSE listed midstream natural gas company.

Henry Goodrich is the Chairman of the Board of Directors—Emeritus. Mr. Goodrich began his career as an exploration geologist with the Union Producing Company and McCord Oil Company in the 1950's. From 1971 to 1975, Mr. Goodrich was President, Chief Executive Officer and a partner of McCord-Goodrich Oil Company. In 1975, Mr. Goodrich formed Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company. He was elected to the Company's board in August 1995, and served as Chairman of the Board from March 1996 through February, 2003. Mr. Goodrich is also a director of Pan American Life Insurance Company. Henry Goodrich is the father of Walter G. Goodrich.

Josiah T. Austin is the managing member of El Coronado Holdings, L.L.C., a privately owned investment holding company. He and his family own and operate agricultural properties in the state of Arizona and northern Sonora, Mexico through El Coronado Ranch & Cattle Company, L.L.C. and other entities. Mr. Austin previously served on the Board of Directors of Monterey Bay Bancorp of Watsonville, California, and is a prior board member of New York Bancorp, Inc., which merged with North Fork Bancorporation in early 1998. He is an active investor in publicly traded financial institutions. He became one of the Company's directors in August 2002.

John T. Callaghan is the Managing Partner of Callaghan & Nawrocki, L.L.P, an audit, tax and consulting firm located on Long Island, New York. He is a Certified Public Accountant and a member of the Association of Certified Fraud Examiners. He was employed by a major accounting firm from 1979 until 1986, at which time he formed his present firm. Mr. Callaghan also serves as a director and chairman of the Finance Committee of both Andrea Systems, Inc. and the Friends of Long Island Heritage. He was elected to the Company's Board of Directors in June 2003.

Geraldine A. Ferraro is an Executive Vice President and head of the public affairs practice of The Global Consulting Group, a New York-based international investor relations and corporate communications firm providing advisory services to public companies, private firms and governments around the world. Ms. Ferraro serves as a Board member of the National Democratic Institute of International Affairs and a member of the Council on Foreign Relations and was formerly United States Ambassador to the United Nations Human Rights Commission. Ms. Ferraro has been affiliated with numerous public and private sector organizations, including serving as a director of the former New York Bancorp, a NYSE-listed company. She was elected to the Company's Board of Directors in August 2003.

Michael J. Perdue is the President and Chief Executive Officer of Community Bancorp Inc., a publicly traded bank holding company based in Escondido, California. Prior to assuming his present position in July 2003, Mr. Perdue was Executive Vice President of Entrepreneurial Corporate Group and President of its subsidiary, Entrepreneurial Capital Corporation. Prior to joining ECG in April 1999, Mr. Perdue served as Senior Vice President and Regional Manager of Zions Bancorporation from May 1998 to April 1999 and as Executive Vice President, Chief Operating Officer and a Director of FP Bancorp, Inc. and its wholly-owned subsidiary, First Pacific National Bank, from September 1993 until FP Bancorp's acquisition by Zions Bancorporation in May 1998. He has also held senior management positions with Rampac, Inc., a real estate development company, and PacWest Bancorp. He was elected to the Company's Board of Directors in January 2001.

Arthur A. Seeligson is currently engaged in the management of his personal investments in Houston, Texas. From 1991 to 1993, Mr. Seeligson was a Vice President, Energy Corporate Finance, at Schroder Wertheim & Company, Inc. From 1993 to 1995, Mr. Seeligson was a Principal, Corporate Finance, at Wasserstein, Perella & Co. He was primarily engaged in the management of his personal investments from 1995 through 1997. He was a managing director with the investment banking firm of Harris, Webb & Garrison from 1997 to June 2000. He has served as one of the Company's directors since August 1995.

Gene Washington is the Director of Football Operations with the National Football League in New York. He previously served as a professional sportscaster and as Assistant Athletic Director for Stanford University prior to assuming his present position with the NFL in 1994. Mr. Washington serves and has served on numerous corporate and civic boards, including serving as a director of the former New York Bancorp, a NYSE-listed company. He was elected to the Company's Board of Directors in June 2003.

Steven A. Webster is the Managing Director of Global Energy Partners, an affiliate of the Merchant Banking Division of Credit Suisse First Boston, which makes private equity investments in the energy industry. He was Chairman and Chief Executive Officer of Falcon Drilling Company, a marine oil and gas drilling contractor from 1988 to 1997, and was President and Chief Executive Officer of its successor, R&B Falcon Corporation from 1998 to 1999. Mr. Webster is Chairman of the Board of Carrizo Oil & Gas, Inc., a NASDAQ traded oil and gas exploration company, and serves on the board of directors of six other public companies, primarily in the energy industry. He also serves on the board of directors of numerous private energy companies. He was elected to the Company's Board of Directors in August 2003.

Additional information required under Item 10, "Directors and Executive Officers of the Registrant," will be provided in the Company's Proxy Statement for the 2004 Annual Meeting of Stockholders.

Item 11. ***Executive Compensation.***

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

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

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Item 14. ***Principal Accounting Fees and Services.***

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* Reference is made to information under the captions "Executive Compensation", "Security Ownership of Certain Beneficial Owners and Management", "Certain Relationships and Related Transactions" and "Principal Accounting Fees and Services", in the Company's Proxy Statement for the 2004 Annual Meeting of Stockholders.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

(a) 1. Financial Statements

The following consolidated financial statements of Goodrich Petroleum Corporation are included in Part II, Item 8:

2. Financial Statement Schedules

The schedules for which provision is made in Regulation S-X are not required under the instructions contained therein, are inapplicable, or the information is included in the footnotes to the financial statements.

(b) Reports on Form 8-K

On November 17, 2003, the Company filed a Form 8-K report containing its Third Quarter 2003 Earnings Release.

(c) Exhibits

3(i).1 Amended and Restated Certificate of Incorporation of Goodrich Petroleum Corporation dated March 12, 1998 (Incorporated by reference to Exhibit 3.1 of the Company's First Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed November 22, 2000.

3(ii).1 Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.3 of the Company's First Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed November 22, 2000.

4.1 Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.6 of the Company's Registration Statement filed February 20, 1996 on Form S-8 (File No. 33-01077)).

4.2 Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated November 9, 2001 (Incorporated by reference to Exhibit 4.2 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

10.1 Goodrich Petroleum Corporation 1995 Stock Option Plan (Incorporated by reference to Exhibit 10.21 to the Company's Registration Statement filed June 13, 1995 on Form S-4 (File No. 33-58631)).

10.2 Consulting Services Agreement between Patrick E. Malloy and Goodrich Petroleum Corporation dated June 1, 2001 (Incorporated by reference to Exhibit 10.3 of the Company's Annual Report filed on Form 10-K for the year ended December 31, 2001).

10.3 Goodrich Petroleum Corporation 1997 Nonemployee Director Compensation Plan (Incorporated by reference to the Company's Proxy Statement filed April 27, 1998).

10.4 Form of Subscription Agreement dated September 27, 1999 (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K dated October 15, 1999).

10.5 Purchase and Sale Agreement between Goodrich Petroleum Company, LLC and Malloy Energy Company, LLC, dated March 4, 2002 (Incorporated by reference to Exhibit 10.7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2002).

21 Subsidiaries of the Registrant

Goodrich Petroleum Company LLC— organized in state of Louisiana

Goodrich Petroleum Company—Lafitte, LLC—organized in state of Louisiana

Drilling & Workover Company, Inc.—incorporated in state of Louisiana

LECE, Inc.—incorporated in the state of Texas

*23 Consent of KPMG LLP.

*31.1 Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*31.2 Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*32.1 Certification by Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*32.2 Certification by Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GOODRICH PETROLEUM CORPORATION
(Registrant)

By: /s/ WALTER G. GOODRICH
Walter G. Goodrich
Chief Executive Officer

Date: April 12, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Date: April 12, 2004

Signature	Title
/s/ WALTER G. GOODRICH **Walter G. Goodrich**	Vice Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ D. HUGHES WATLER, JR. **D. Hughes Watler, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ KIRKLAND H. PARNELL **Kirkland H. Parnell**	Vice President (Principal Accounting Officer)
/s/ PATRICK E. MALLOY, III **Patrick E. Malloy, III**	Chairman of Board of Directors
/s/ JOSIAH T. AUSTIN **Josiah T. Austin**	Director
/s/ JOHN T. CALLAGHAN **John T. Callaghan**	Director
/s/ GERALDINE A. FERRARO **Geraldine A. Ferraro**	Director
/s/ HENRY GOODRICH **Henry Goodrich**	Director
/s/ MICHAEL J. PERDUE **Michael J. Perdue**	Director
/s/ ARTHUR A. SEELIGSON **Arthur A. Seeligson**	Director
/s/ GENE WASHINGTON **Gene Washington**	Director
/s/ STEVEN A. WEBSTER **Steven A. Webster**	Director

Board of Directors

Patrick E. Malloy III (1*) (4*)
Chairman of the Board
Goodrich Petroleum Corporation
President and CEO
Malloy Enterprises, Inc.

Walter G. Goodrich (1) (4)
Vice Chairman and CEO
Goodrich Petroleum Corporation

Henry Goodrich (1)
Chairman - Emeritus
Goodrich Petroleum Corporation

Josiah T. Austin (3*) (4)
Banking and Ranching

John Callaghan (2)
Callaghan Nawrocki, LLP

Geraldine A. Ferraro (2)
Managing Director
The Global Consulting Group

Michael J. Perdue (2*)
President and CEO
Community National Bank

Arthur A. Seeligson (1) (2) (3)
Private Investments

Gene Washington (3)
Director Football Operations
National Football League

Steven A. Webster
Managing Director
Global Energy Partners

(1) Member of Executive Committee
(2) Member of Audit Committee
(3) Member of Compensation Committee
(4) Member of Hedging Committee
(*) Denotes Chairman of Committee

Management

Chairman of the Board
Patrick E. Malloy III

Vice Chairman and Chief Executive Officer
Walter G. "Gil" Goodrich

President and Chief Operating Officer
Robert C. Turnham, Jr.

Senior Vice President, Engineering and Operations
Mark E. Ferchau

Senior Vice President, Chief Financial Officer and Treasurer
D. Hughes Watler, Jr.

Vice President, Finance and Controller
Kirkland H. Parnell

Vice President, Engineering and Operations
Jim B. Davis

Vice President, Corporate Planning and Business Development,
Henry Goodrich, Jr.

Corporate Offices

Corporate Headquarters
808 Travis, Suite 1320
Houston, Texas 77002

333 Texas Street, Suite 1375
Shreveport, Louisiana 71101

Independent Auditors

KPMG LLP
Shreveport, Louisiana

Transfer Agent

Computershare Investor Services
755 Lucerne Drive, Suite 103
Cleveland, OH 44130

Securities

Common Stock traded on New York Stock Exchange, symbol GDP

Series A Convertible Preferred Stock traded on NASDAQ Small-Cap, symbol GDPAP

Annual Meeting of Shareholders

The Annual Meeting of Shareholders will be held in Houston, Texas on June 8, 2004 at 11:00 A.M. Central Time. A notice and proxy statement will be distributed to all shareholders in April 2004.

SEC Form 10-K

The Company's 2003 report to the Securities Exchange Commission on Form 10-K is available without charge upon request to the Company's Shreveport office. This report is prepared for the information of security holders, employees and other interested persons. It is not transmitted in connection with the sale of any security or offer to sale or offer to sale or offer to buy any security.

Web Site

Information about Goodrich Petroleum, including an archive of news releases, access to SEC filings, and documents relating to corporate governance, is available from the company's Web site at www.goodrichpetroleum.com

GOODRICH
PETROLEUM CORPORATION

ANNUAL REPORT 2003

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