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GeoResources, Inc.
2003 Annual Report

GeoResources, Inc. is a natural resources company engaged in three principal business segments – oil and gas exploration, development and production; oil and gas drilling; and leonardite mining and the manufacture of leonardite-based products. GeoResources, Inc. is traded on the Nasdaq SmallCap Market under the symbol "GEOI."

GeoResources has a substantial oil and gas exploration and production operation in the Williston Basin. This business segment historically constitutes more than 70 percent of GeoResources' revenue and earnings. In 2003, the Company produced an average of 376 net equivalent barrels of oil per day from 141 productive wells located within 50 fields in North Dakota and Montana. At December 31, 2003, GeoResources owned proved reserves of 2.5 million barrels of oil equivalent with an SEC value of $21 million. Ninety-seven percent of those reserves are crude oil.

Due to the shortage of working drilling rigs in some portions of the Williston Basin, in late 2001 GeoResources elected to form a subsidiary company, Western Star Drilling Company, and acquire a drilling rig for its own use and for contract drilling operations. In September 2001, GeoResources purchased a drilling rig capable of drilling to 8,000 feet. After retrofitting was completed, the rig was deployed in the north central region of North Dakota.

In addition to its oil and gas activities, the Company operates a leonardite mine and processing plant at Williston, North Dakota. At the Williston facility a distinctive type of oxidized lignite coal called leonardite is mined from leased reserves and processed into several different specialty products. Those products include drilling mud additives for use in the oil and natural gas drilling industry and applications in metal working factories and in agriculture.

THE YEAR AT A GLANCE

(financial highlights in $000s except per share, production and reserve data)	2003	2002	2001	2000	1999
For the Year					
Oil and Gas Revenues	$ 3,615	$ 2,980	$ 3,064	$ 4,436	$ 2,689
Leonardite Revenues	822	727	1,152	889	873
Drilling	406	281	–	–	–
Total	$ 4,843	$ 3,988	$ 4,216	$ 5,325	$ 3,562
Net Income (Loss)	$ 447	$ 91	$ 42	$ 1,415	$ 482
Per Share	$ .12	$ .02	$ .01	$ .36	$ .12
At Year End					
Working Capital (Deficit)	$ (173)	$ 311	$ (224)	$ 424	$ 639
Total Assets	$ 11,584	$ 9,048	$ 8,202	$ 7,450	$ 7,329
Long-Term Debt	$ 1,599	$ 1,910	$ 1,035	$ 375	$ 1,610
Current Maturities	$ 479	$ 132	$ 125	$ 125	$ 175
Stockholders' Equity	$ 5,974	$ 5,616	$ 5,536	$ 5,713	$ 4,462
Production Statistics					
Productive Wells (gross)	141	139	134	134	134
Oil (bbls)	135,865	140,468	149,916	165,156	182,356
Gas (mcf)	8,234	10,374	11,496	10,139	8,042
Leonardite (tons)	6,558	6,511	9,779	7,696	7,736
Proved Reserves At Year End					
Oil (bbls)	2,458,000	2,487,000	2,098,000	2,487,000	2,566,000
Gas (mcf)	387,000	421,000	350,000	545,000	257,000

LETTER TO SHAREHOLDERS

APRIL 14, 2004

GeoResources operates in three primary segments, oil and gas exploration and production, oil and gas drilling, and leonardite mining and processing. During 2003 we accomplished the majority of our operational goals. Our financial performance was further augmented by substantially higher values for the commodities we produce in our oil and gas segment.

In varying degrees the worldwide price of oil and gas is core to all of our business segments. An average annual NYMEX oil price advancing from $14.43 per barrel in 1998 to $31.04 per barrel in 2003 benefited our financial performance and has sparked a renewed fervor for the oil and gas industry, particularly independents in the US domestic "oil patch". We realize consumers, including our shareholders, benefited from low priced gasoline during this period. But the substantially lower, some would say ridiculously lower, oil prices of the late 1980's and 1990's has contributed to the higher price "problem" we see today. A $14.50 per barrel oil price in 1998 adjusted for inflation back to 1975 is equivalent to $4.80 per barrel. That compares to the real dollar price in 1975 of $12.82 per barrel. By the same token the $12.82 per barrel real price in 1975 translates to $44.50 per barrel in today's dollars. Suffice it to say that the oil and gas industry has been through a tough 20-year period when oil prices did not justify capital expenditures to find new supplies. That lack of new supply has resulted in the current cycle of higher prices that we believe may be sustained for some time.

Our net income was significantly impacted by higher commodity prices resulting in a 391% increase over the prior year to $447,000 or $0.12 per share compared $91,000 or $0.02 per share in 2002. We drilled two successful wells during the year and completed numerous workovers, which offset most of our normal production decline. Annual production was down approximately 3% to 137,237 barrels of oil equivalent while year-end reserves were 2.5 million barrels of oil equivalent with an after tax SEC PV-10 value of $15.6 million.

We have budgeted $1 million for drilling and recompletion projects in 2004 and drilled our first well, a development well in our Landa Field of Bottineau County, North Dakota in the first quarter. The well appears to be productive from drilling information and open hole logging data and we expect to begin completion operations soon.

More details of our operational and financial progress through 2003 are presented in the pages of this Annual Report to Shareholders. However, on a more personal level, I would like to remark on the retirement of Tom Neubauer at year-end 2003. This is more than a bit nostalgic for me, as Mr. Neubauer and my father built GeoResources' first leonardite processing plant in 1964 when I was merely 12 years old. Cash flow from that plant launched GeoResources into the oil business that is its main business today. Tom is a true leader and he excelled at managing employees, customers, suppliers and all he came in contact with for his entire 40-year career. We will miss Tom but we wish him all the best and continued good health in his retirement.

We truly appreciate the capabilities and dedication of all our employees. We rely on our directors for their guidance and advice. And finally, all of us at GeoResources, Inc., thank you, our shareholders, for your continued interest and investment in the company's future.

Sincerely,

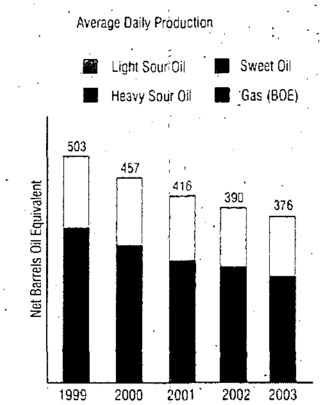
J. P. (Jeff) Vickers, President

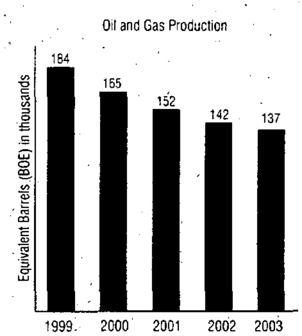
EXPLORATION & PRODUCTION

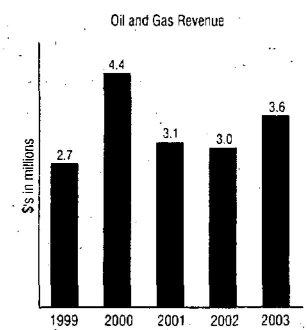
During 2003 we drilled one productive well in our South Starbuck Madison Unit, an exploratory dry hole in our Kramer prospect and one productive development well in our Leonard Field all in Bottineau County, North Dakota. GeoResources owns a 99% working interest in the South Starbuck Madison Unit well and 100% working interest in the remaining two wells. The Leonard Field well was initially completed late in the fourth quarter. However we believe the well has substantially greater production potential than current rates and we plan to apply some stimulation techniques to increase the wells production in 2004.

Our 2004 budget for drilling and workovers will again be about $1 million as it was in 2003. Our first well for 2004 has already been drilled, a productive development well in our Landa Field. We have a 75% working interest in the well. We plan to drill at least two more wells in 2004 from an inventory of projects that includes five proven undeveloped locations and two exploratory locations. The final selection of the specific projects will depend on the availability of our Western Star Drilling Rig E-25, the availability of other drilling equipment, permitting and other factors.

In addition to our planned drilling for 2004, we expect to form another new unit for the purpose of secondary recovery by water-flood and perform a significant amount of work-over and other remedial work.







	2003		2002	
	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Proved Developed				
Producing	1,605	44	1,548	70
Nonproducing	30	343	34	351
Proved Undeveloped	823	--	905	--
Total Proved Reserves	2,458	387	2,487	421
Total Proved Reserves (MBOE)	2,523		2,557	
Future Cash Flow from Proved Reserves (M$)	$ 37,925		$ 34,978	
Future Cash Flow Discounted at 10% (M$)	$ 21,444		$ 19,814	
Standardized Measure of Discounted Future Net Cash Flows (M$)	$ 15,567		$ 14,458	

Productive Wells*

	Oil		Gas	
Year	Gross	Net	Gross	Net
2003	115	87.62	26	25.25
2002	113	85.57	26	25.25
2001	108	80.13	26	25.25
2000	108	80.12	26	25.75
1999	110	80.04	24	24.00

	Producing Wells				Service Wells	
	Oil		Gas			
Year	Gross	Net	Gross	Net	Gross	Net
2003	103	78.10	0	0.00	14	11.93
2002	107	79.07	0	0.00	14	11.93
2001	108	80.14	0	0.00	15	12.41
2000	107	80.05	0	0.00	15	12.41
1999	107	78.99	0	0.00	15	12.39

*Producing wells and nonproducing wells deemed capable of production.

Western Star Drilling Company

OPERATING DATA - RIG E-25

		2003		2002
Operating Days		85		55
Operating Footage		20,122		20,476
Operating Revenue	$	406,141	$	280,500
Total Revenue	$	608,104	$	413,871

DRILLING

Our subsidiary, Western Star Drilling Company, gives us rig access to actively pursue drilling objectives while at the same time providing possible revenue from other operators' projects. It also gives us more control over the timing of projects and makes our drilling operations more self-sufficient.

Our Rig E-25 is a well-built conventional "little double," designed for shallow drilling with a 102-foot, 350,000-pound mast and a 250,000-pound draw-works. The rig features a large, spacious, well-lighted doghouse that houses the drilling instrumentation and tools. Some of the rig's safety features include a flush mounted "racking board" on the drilling floor. Several features of Rig E-25, including a 14-foot substructure, make it suitable for drilling vertical wells to depths of less than 8,000 feet, horizontal wells with similar true vertical depths and for under-balanced horizontal drilling.

During 2003, Rig E-25 was utilized to drill three wells for us and two wells for other operators. A rig is considered utilized when it is operated or being moved, assembled, or dismantled under a contract. The optimum utilization of Rig E-25 would allow for drilling approximately 20 wells per year of the type and depth that are typical in the shallower portions of the Williston Basin.

LEONARDITE

GeoResources, has selectively mined leonardite (often loosely called "lignite") from our own mine for the past 39 years. Our leonardite processing plant offers the petroleum industry the finest drilling fluid dispersants and viscosity control products in the world.

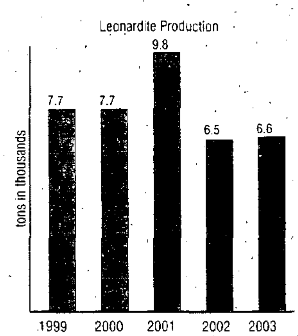
Our high-quality leonardite is marketed worldwide under the trade names LEN-OX, LEN-ALK and numerous private branded products. We also manufacture specially blended lignite that is used in both the oil and agricultural industries.

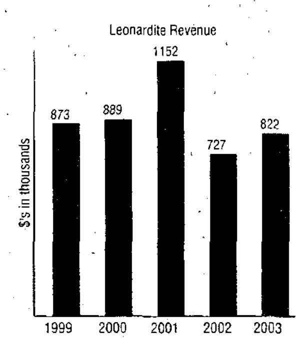
LEN-OX (Regular Lignite)

- controls filtration
- thins water based mud
- reduces water loss
- stabilizes oil-in-water emulation
- retains dispensing power of high hold temperatures
- maintains surfactant quality in salt water

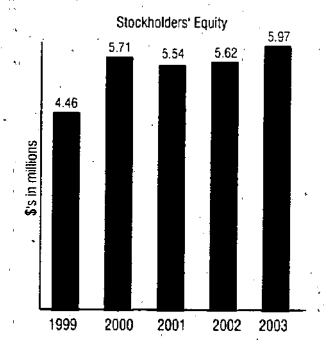
LEN-ALK (Causticized Lignite)

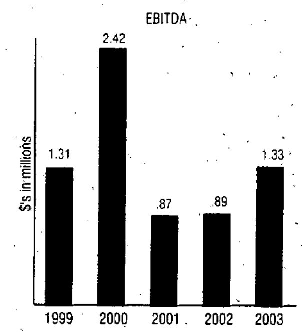
- emulsifies effectively
- provides stable and contamination-resistant oil-in-water emulsions
- thins fresh and brackish water mud effectively
- gives mud excellent fluid loss properties
- controls filtration
- tolerates high temperatures and soluable contaminants

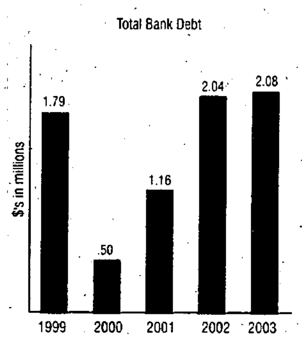


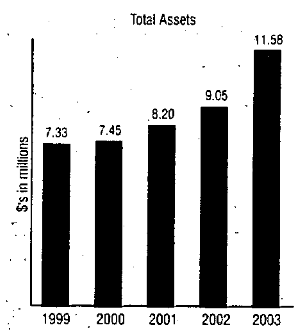


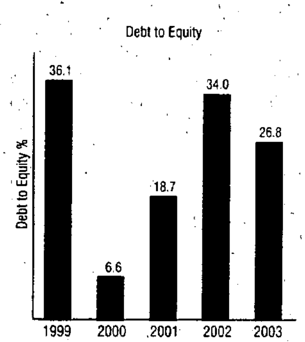
FINANCIAL PERFORMANCE

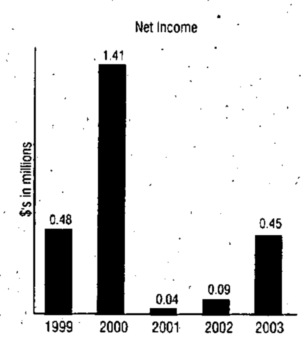












U. S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

(Mark One)

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended **December 31, 2003.**

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from ____________________ to ____________________.

Commission File Number – 0-8041

GEORESOURCES, INC.

Colorado (State or other jurisdiction of incorporation or organization	84-0505444 (I.R.S. Employer Identification No.)
1407 West Dakota Parkway, Suite 1-B Williston, North Dakota (Address of Principal executive offices)	58801 (Zip Code)
(Issuer's telephone number including area code)	(701) 572-2020

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12 (g) of the Act: Common Stock, par value $0.01

Check whether the Issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the Issuer was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB. [X]

Issuer's revenues for its most recent fiscal year. $4,842,952

The aggregate market value of the voting and non-voting common equity computed by reference to the average bid and ask price of such common equity held by nonaffiliates as of March 15, 2004, was approximately $6,557,427.

Shares of $0.01 par value Common Stock outstanding at March 15, 2004: 3,723,977

PART I.

ITEM 1. DESCRIPTION OF BUSINESS

General Development of Business

GeoResources, Inc. is a natural resources company engaged in three principal business segments: 1) oil and gas exploration, development and production; 2) oil and gas drilling; and 3) mining of leonardite (oxidized lignite coal) and manufacturing of leonardite based products which are sold primarily as oil and gas drilling mud additives. We were incorporated under Colorado law in 1958 and were originally engaged in uranium mining. We built our first leonardite processing plant in 1964 in Williston, North Dakota, and began participating in oil and gas exploration and production in 1969. In 1982, we completed construction of a larger leonardite processing plant in Williston that is in use today. We purchased our oil and gas drilling rig in 2001 and formed a subsidiary for drilling operations in 2002. Financial information about our three operating segments is presented in Note B to the Financial Statements in Item 7 of this report.

Information contained in this Form 10-KSB contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 which can be identified by the use of words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or variations of these words or comparable terminology. In addition, all statements other than statements of historical facts that address activities, events or developments that we expect, believe or anticipate will or may occur in the future, and other such matters, are forward-looking statements.

Our future results may vary materially from those anticipated by management and may be affected by various trends and factors which are beyond our control. Please review some of the more significant risks we face under the heading "Risk Factors" presented at the end of this item.

Oil and Gas Exploration, Development and Production

Our oil and gas exploration and production efforts are concentrated on oil properties in the North Dakota and Montana portions of the Williston Basin. We typically generate prospects for our own exploitation, but when we believe a prospect may have substantial risk or cost, we may attempt to raise all or a portion of the funds necessary for exploration or development through farmouts, joint ventures, or other similar types of cost-sharing arrangements. The amount of interest retained by us in a cost-sharing arrangement varies widely and depends upon many factors, including the exploratory costs and the risks involved.

In addition to originating our own prospects, we occasionally participate in exploratory and development prospects originated by other individuals and companies. We also evaluate interests in various proved properties to acquire for further operation and/or development.

As of December 31, 2003, we had developed oil and gas leases covering approximately 15,600 net acres in Montana and North Dakota, and during 2003 sold an average 376 net equivalent barrels of oil per day from 141 gross (113 net) productive wells located primarily in North Dakota.

We sell our crude oil and natural gas to purchasers with facilities located near our wells.

Oil and Gas Drilling

Due to a shortage of working drilling rigs we believe exists in some portions of the Williston Basin area, we elected to form a subsidiary company to own and operate a rig for our own use and for contract drilling operations. In September 2001, we purchased a drilling rig capable of drilling to 8,000 feet. After retrofitting, the rig was deployed in the north central region of North Dakota. In January 2002, our subsidiary company, Western Star Drilling Company ("WSDC"), was incorporated. We transferred the rig and all related equipment to WSDC in exchange for 100% of WSDC's outstanding stock. WSDC's rig consists of engines, drawworks, a mast, pumps, blowout preventers, a drillstring, and related equipment. From time to time, the rig will be used to drill our prospects; however, WSDC will also contract with other entities to drill their wells. We believe that the ownership of WSDC will accelerate the development of our leasehold acreage while providing an additional revenue stream through contract drilling.

WSDC provides the rig, equipment and personnel on a contract basis. The drilling contracts are obtained through competitive bidding or as a result of negotiations with customers. To date, all of the drilling contracts have been performed on a "daywork" basis, under which a fixed rate is charged per day, with the price determined by the location, depth, and complexity of the well to be drilled, operating conditions and the competitive forces of the market. In most instances, contracts provide for additional payments for mobilization and demobilization of the rig.

Mining and Manufacturing of Leonardite Products

We operate a leonardite mine and processing plant in Williston, North Dakota. Leonardite is mined from leased reserves and processed to make a basic product that can be sold as is, or blended with other substances to make several different powdered specialty products which are used primarily in the oil well drilling mud industry. Leonardite products act as a dispersant or thinner and provide filtration control when used as an additive in drilling muds. Leonardite is also sold by us for use in metal working foundries and in agricultural applications.

In 2003, our leonardite products were sold primarily to drilling mud companies located in coastal areas of the Gulf of Mexico. Demand for our plant's output is governed mainly by the level of oil and gas drilling activities, particularly in the gulf coast area, both onshore and offshore. Drilling activity has remained at relatively low levels for periods of time during the past several years. We have no significant leonardite supply contracts with individual customers.

Status of Products, Services or Industry Segments in Development

We own all the stock of Western Star Drilling Company ("WSDC"), a North Dakota corporation formed to provide contract oil and gas well drilling services. WSDC's drilling equipment can be expanded to allow a greater realm of project and drilling technology capabilities. We may devote resources to this segment if warranted by economic conditions in the drilling industry.

We own 85% of the voting stock of Belmont Natural Resource Company, Inc. ("BNRC"), a Washington corporation formed for the purpose of exploiting natural gas opportunities in the Pacific Northwest. BNRC owns oil and gas leases covering 3,273 gross acres (2,804 net) on a gas prospect in the State of Washington. We do not expect to devote any substantial resources on this prospect in 2004.

We also own land under seven patented mining claims in Arizona, as well as a minor amount of geothermal and other mineral rights in Oregon. We do not expect to devote any substantial resources to hard mineral or geothermal exploration or development in 2004, however we do anticipate the Arizona property will begin actual commercial rock production in 2004 under a lease agreement. (See Item 2.)

Sources and Availability of Raw Materials and Leases

Maintaining sufficient leasehold mineral interests for oil and gas exploration and development is a primary continuing need in the oil and gas business. We believe that our current undeveloped acreage is sufficient to meet our presently foreseeable oil and gas leasehold needs. Maintaining sufficient leasehold mineral interests for leonardite mining is also a continuing need for our mining and manufacturing of leonardite products. We believe the leonardite held under our current leases is sufficient to maintain our present output for many years. (See Item 2.)

Major Customers

In 2003, we sold our crude oil to 18 purchasers. Plains Marketing Canada, L.P. and Flint Hills Resources were the major purchasers, accounting for approximately 49% and 38%, respectively, of our oil and gas revenue in 2003 or approximately 36% and 28%, respectively, of our total operating revenue. We believe there are other crude oil purchasers to whom we would be able to sell our oil if any of our current purchasers discontinued purchasing from us.

In 2003, we sold leonardite products to 39 customers. The largest customer in 2003 for leonardite products made purchases totaling 30% of our mining and manufacturing revenue or approximately 5% of our total operating revenue.

In 2003, WSDC had two customers. The largest customer accounted for approximately 78% of our drilling revenue or approximately 7% of our total operating revenue.

Backlog Orders, Research and Development

We do not have any material long-term or short-term contracts to supply leonardite products. All orders are reasonably expected to be filled within three weeks of receipt. From time to time, we enter into short-term contracts to deliver any quantities of oil or gas; however, no significant backlog exists. Our oil and gas division order contracts and any off-lease-marketing arrangements are typical of those in the industry with 30 to 90 day cancellation notice provisions. They generally do not require long-term delivery of fixed quantities of oil or gas. We have not spent any material time or funds on research and development and do not expect to do so in the foreseeable future.

Competition

Oil and Gas In addition to being highly speculative, the oil and gas business is intensely competitive among the many independent operators and major oil companies in the industry. Many competitors possess financial resources and technical facilities greater than those available to us and they may, therefore, be able to pay more for desirable properties or to find more potentially productive prospects. However, we believe we have the ability to obtain leasehold interests which will be sufficient to meet our oil and gas needs in the foreseeable future.

Leonardite Products Uses and specifications of leonardite-based drilling mud additives are subject to change if better products are found. Our leonardite products compete with leonardite and non-leonardite products used as additives in numerous types of drilling mud. In addition, leonardite deposits are available in other areas within the United States, and competitors may be able to enter the leonardite business with relative ease. At the present time, similar products are marketed by other companies who mine, process and market leonardite products. Competition lies primarily in delivery time, transportation costs, quality of the product, performance of the product when used in drilling mud and access to high-quality leonardite deposits. In addition, higher fuel prices can significantly affect our leonardite operations because our processing is located in a colder climate.

Contract Drilling The contract drilling business is highly competitive. Contract drilling competition involves price, rig availability and capability, rig condition, reputation, customer relations and many other factors. However, we believe there is a current shortage of drilling rigs available in shallow drilling areas of the Williston Basin.

Contract drilling and oil and natural gas activities are subject to a number of risks and hazards. These could cause serious injury or death to persons, suspension of drilling operations, serious damage to equipment or property of others, and damage to producing formations in surrounding areas. Our operations could also cause environmental damage, particularly through oil spills, gas leaks, discharges of toxic gases or extensive uncontrolled fires. In addition, we could become subject to liability for reservoir damages. The occurrence of a significant event, including pollution or environmental damage, could materially affect our operations and financial condition. We believe we are adequately insured or indemnified against normal and foreseeable risks in our operations in accordance with industry standards. However, such insurance or indemnification may not be adequate to protect us against liability from all consequences of well disasters, extensive fire damage or damage to the environment. Likewise, we cannot assure that we will be able to maintain adequate insurance in the future at reasonable rates or that any particular types of coverage will be available.

Environmental Regulations

All of our operations are generally subject to numerous stringent federal, state and local environmental regulations under various acts including the Comprehensive Environmental Response, Compensation and Liability Act; the Federal Water Pollution Control Act; and the Resources Conservation and Recovery Act.

For example, our oil and gas business segment is affected by diverse environmental regulations including those regarding the disposal of produced oilfield brines, other oil-related wastes, and wastes not directly related to oil and gas production. Additional regulations exist regarding the containment and handling of crude oil as well as preventing the release of oil into the environment and a number of others. It is not possible to estimate future environmental compliance costs due in part to the uncertainty of continually changing environmental initiatives. While future environmental costs can be expected to be significant to the entire oil and gas industry, we do not believe our costs would be any more of a relative financial burden than those of our peers and that environmental compliance costs will be recovered in the marketplace. During 2003 and 2002, environmental compliance costs identified to an actual account were $5,470 and $4,230, respectively. However, that is materially less than the real costs, because compliance costs are complex and difficult to differentiate in a system of invoicing.

Our leonardite mining and processing segment is also subject to an abundant number of federal, state and local environmental regulations, particularly those concerned with air contaminant emission levels of our processing plant and mine permit and reclamation regulations pertaining to surface mining at our leonardite mine. We believe that maintenance of acceptable air contaminant emission levels at our processing plant could become more costly in the future if plant production increases substantially above levels experienced over the past several years. Management believes significantly higher plant utilization would increase emission levels and could make it necessary to replace or upgrade air quality control equipment. Environmental compliance costs that might be required to upgrade air quality control equipment cannot be reasonably estimated because future regulatory requirements are unknown.

Foreign Operations and Export Sales

We have no production facilities or operations in foreign countries but may export to Mexico. Some of our leonardite products are sold to distributors in the United States who in turn export these products.

Employees

At March 15, 2004, we employed 12 persons on a full-time basis, including our officers. None of our employees are represented by unions. We consider our relationships with our employees to be excellent.

Risk Factors

Our operations are subject to a variety of risks, including the following:

We must successfully acquire or develop additional reserves of oil and gas.

Our future production of oil and gas is highly dependent upon our level of success in acquiring or finding additional reserves. The rate of production from our oil and gas properties generally decreases as reserves are depleted. We compete with a number of exploration and production companies that possess greater financial resources than are available to us. We may not be able to economically compete for oil and gas properties due to a lack of capital and inability to obtain adequate financing which may be required to fund property acquisitions. To the extent financing is obtained, it may not be on terms beneficial to our stockholders.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices will also negatively impact the value of our proved reserves. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We face significant competition.

We operate in a highly competitive environment. We compete with major integrated and independent oil and gas companies for the acquisition of desirable oil and gas properties and leases, for the equipment and labor required to develop and operate such properties, and in the marketing of oil and gas to end-users. Many of our competitors have financial and other resources substantially greater than us. In addition, many of our larger competitors may be better able to respond to factors that affect the demand for oil and natural gas production, such as changes in worldwide oil and natural gas prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also compete in attracting and retaining technical personnel, including geologists, geophysicists and other specialists.

We also face the same competitive matters discussed above with respect to our leonardite operations.

Our reported reserves of oil and gas represent estimates which may vary materially over time due to many factors.

Generally. Our estimated reserves may be subject to downward revision based upon future production, results of future development, prevailing oil and gas prices, operating and development costs and other factors. There are numerous uncertainties and uncontrollable factors inherent in:

- estimating quantities of oil and gas reserves,
- projecting future rates of production, and
- timing of development expenditures.

In addition, the estimates of future net cash flows from our proved reserves and the present value of such reserves are based upon various assumptions about future production levels, prices and costs that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of our reserves and amount of estimated future net cash flows from our estimated oil and gas reserves.

Proved Reserves; Ceiling Test. A deterioration of oil or gas prices could result in our recording a non-cash charge to earnings at the end of a quarter or year. Our proved reserve estimates are based upon an independent analysis of our oil and gas properties and are subject to rules set by the SEC. We periodically review the carrying value of our oil and gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects. At the end of each quarter, the test is applied using unescalated prices in effect at the applicable time and may result in a write-down if the "ceiling" is exceeded, even if prices decline for only a short period of time. We have made write downs of the carrying value of our oil and gas properties on our financial statements in the past due to low prices, and may do so in the future.

Any hedging activities we engage in may prevent us from realizing the benefits in oil or gas price increases.

To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges during certain time periods. From time to time, we have engaged in hedging activities with respect to some of our projected oil and gas production through financial arrangements designed to protect against price declines, such as swaps, collars and futures agreements. We currently are not a party to any hedging contracts but may engage in hedging in the future.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance, if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We face extensive government regulation, which can negatively impact the success of our operations and financial success.

The oil and gas and mining industries are extensively regulated by federal, state and local authorities. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of our oil, gas and leonardite production. Substantial penalties may be assessed for noncompliance with various applicable statutes and regulations, and the overall regulatory burden on the industry increases its cost of doing business and, in turn, decreases its profitability. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment, and restoration.

We are dependent upon the services of our Chief Executive Officer.

We are highly dependent on the services of our Chief Executive Officer, Jeffrey P. Vickers. We do not have an employment agreement with Mr. Vickers, nor do we carry any key man life insurance on Mr. Vickers. The loss of his services would likely negatively impact our operations.

ITEM 2. PROPERTIES

Our properties consist of five main categories: Office, oil and gas exploration and production, oil and gas drilling rig, leonardite plant and mine, and our Reymert property. Certain of these properties are mortgaged to our bank. See Note E to the Consolidated Financial Statements included herein under Item 7 for further information.

Office

We own an 18,000 square foot office building, which is located on a one-acre lot in Williston, North Dakota. We use about 9,000 square feet of the building and rent the remainder to unaffiliated businesses.

Oil and Gas Exploration and Production

We own developed oil and gas leases totaling 20,099 gross (15,554 net) acres as of December 31, 2003, plus associated production equipment. We also own a number of undeveloped oil and gas leases. The acreage and other additional information concerning our oil and gas operations are presented in the following tables.

Estimated Net Quantities of Oil and Gas and Standardized Measure of Future Net Cash Flows All of our oil and gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note M to the Consolidated Financial Statements. The estimates are based upon the report of Broschat Engineering and Management Services, an independent petroleum-engineering firm in Williston, North Dakota. We have no long-term supply or similar agreements with foreign governments or authorities, and we do not own an interest in any reserves accounted for by the equity method.

Net Oil and Gas Production, Average Price and Average Production Cost The net quantities of oil and gas produced and sold by us for each of the last three fiscal years, the average sales price per unit sold and the average production cost per unit are presented below.

Oil & Gas

YEAR	NET OIL PROD. (BBLS)	NET GAS PROD. (MCF)	NET OIL & GAS PROD. (BOE)*	AVERAGE OIL SALES PRICE PER BBL	AVERAGE GAS SALES PRICE PER MCF	AVERAGE PROD. COST PER BOE**
2003	135,865	8,234	137,237	$ 26.42	$ 3.06	$ 13.02
2002	140,468	10,374	142,197	$ 21.10	$ 1.51	$ 11.39
2001	149,916	11,496	151,832	$ 20.25	$ 2.40	$ 12.23

*Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (6 MCF) of natural gas equal to one barrel of oil equivalent (1 BOE).
**Average production cost includes lifting costs, remedial workover expenses and production taxes.

Gross and Net Productive Wells As of December 31, 2003, our total gross and net productive wells were as follows:

Productive Wells*

OIL		GAS		TOTAL	
GROSS WELLS	NET WELLS	GROSS WELLS	NET WELLS	GROSS WELLS	NET WELLS
115	87.62	26	25.25	141	112.87

*There are no wells with multiple completions. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production.

Gross and Net Developed and Undeveloped Acres As of December 31, 2003, we had total gross and net developed and undeveloped oil and gas leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities.

Leasehold Acreage*

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Montana	9,320	7,666	31,733	32,479	41,053	40,145
North Dakota	10,779	7,888	58,613	28,704	69,392	36,592
Washington	0	0	3,273	2,804	3,273	2,804
ALL STATES	20,099	15,554	93,619	63,987	113,718	79,541

*Gross acres are those acres in which a working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

Exploratory Wells and Development Wells Set forth below for the last three fiscal years ended December 31, 2003, is information concerning the number of wells we drilled during the years indicated.

YEAR	NET EXPLORATORY WELLS DRILLED		NET DEVELOPMENT WELLS DRILLED		TOTAL NET PRODUCTIVE OR DRY WELLS DRILLED
	PRODUCTIVE	DRY	PRODUCTIVE	DRY	
2003	0.00	1.00	1.99	0.00	2.99
2002	0.00	0.00	2.99	0.00	2.99
2001	0.00	0.00	0.00	0.00	0.00

Present Activities At March 15, 2004, we did not have any wells in the process of drilling, but we had two approved drilling permits, and the Western Star Drilling Company Rig E25 had been transported to our first location ready to begin drilling about the first week of April. This first well for 2004 is a development well in our Landa Field. For more information on our drilling plans, see Management's Discussion.

Supply Contracts or Agreements We are not obligated to provide a fixed or determinable quantity of oil and gas in the future under any existing contract or agreement, beyond the short-term contracts customary in division orders and off lease marketing arrangements within the industry.

Reserve Estimates Filed with Agencies Information concerning the Company's estimated proved oil and gas reserves and discounted future net cash flows applicable thereto for fiscal 2003, 2002 and 2001 is included as unaudited information in Note M to the Consolidated Financial Statements under Item 7 of this report. In 1999, information concerning portions of the Company's estimated proved oil and gas reserves was provided to the U.S. Department of Energy for fiscal 1998.

Oil and Gas Drilling Rig During 2001 we purchased and retro-fitted a drilling rig and dedicated it to a subsidiary company so it would be available to drill wells for us and other operators. WSDC's Rig designated E25 is capable of depths to 8,000 feet. Three of its primary components are a Drilling Structures Inc. mast rated at a 350,000 pound hook load, an Emsco GB-250 drawworks and an Emsco D-375 mud pump. It is our expectation that this rig will only be utilized to drill wells located in the United States portion of the Williston Basin.

During 2003, the rig was utilized to drill three wells for us and two wells for other operators. A rig is considered to be utilized when it is operated or being moved, assembled, or dismantled under contract. The optimum utilization of the WSDC rig is the drilling of approximately 20 wells per year of the type and depth that are typical in the shallower portions of the Williston Basin. More information of WSDC's drilling operations is included in Management's Discussion.

Leonardite Plant and Mine

The site of our leonardite plant covers about nine acres located one mile east of Williston in Williams County, North Dakota. We own this site and an additional 20 acres of undeveloped property. The plant has approximately 11,500 square feet of floor area consisting of warehousing and processing space. Within the plant is equipment that was, at one time, able to process and ship approximately 3,000 tons of leonardite products per month. Presently, we feel that 2,000 tons of product per month, running 24 hours a day, five days a week, is a more realistic number. The lower capacity is due to several factors including operating with older equipment, maintaining better quality control for our products and meeting the EPA standards for our industry. There are also several factors that affect our sales with the biggest factor probably being competition. Plants that have been built which are more centrally located can ship their product less expensively than we can. Finished product leonardite sales for the past three years are shown below.

YEAR	FINISHED PRODUCTS (TONS)	AVERAGE SALES PRICE PER TON
2003	6,558	$ 125.38
2002	6,511	$ 111.64
2001	9,779	$ 117.83

Our leonardite mining properties consist of a developed lease from private parties and one undeveloped lease from the United States Department of the Interior, Bureau of Land Management. The leased land is located about one mile from our plant site in Williams County, North Dakota. The private-party (fee) lease totals approximately 160 acres and requires a royalty payment per ton scaled to the Producer Price Index, which was approximately $0.75 for the past three years. The federal lease from the Bureau of Land Management (BLM) covers 320 undeveloped acres and requires a minimum royalty of $3.00 per acre or production royalty of 12.5% of value extracted. In 1994, we formed a 240-acre logical mining unit (LMU), in accordance with BLM regulations, consisting of 80 acres of the fee lease and 160 acres of the BLM lease. This LMU allows current operations on the fee lease to satisfy diligent development and other requirements for 160 acres of the BLM lease. We believe that the leonardite contained in the 240-acre LMU is sufficient to supply our plant's raw material requirements for many years and that before these reserves were to be exhausted, we would be able to acquire other fee or federal coal leases in the same area.

Reymert Property

We own seven patented mining claims and 15 unpatented mining claims in the Tonto National Forest in Pinal County, Arizona. These claims, known as the Reymert Property, produced silver sporadically since the 1880's. On May 1, 2002, we entered into a License Agreement-Lease Agreement with Gila Rock Products, L.L.C. ("GRP"), an Arizona Limited Liability Corporation. GRP plans to use this property for producing and marketing decorative rock, boulders, riprap, road-base material and similar commercial rock products. We receive a 10% royalty of gross selling prices on all rock products produced and sold from the property or a minimum royalty of $250 per month. We have no plans to devote significant financial resources to this property in 2004; however, we expect the property to emerge from a licensing and permitting phase and begin actual production in 2004.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in a bankruptcy case with respect to a preference claim brought on November 8, 2002, in the United States Bankruptcy Court, Southern District of Texas, Houston Division (adversary proceeding number 02-03827, In Re: Ramba, Inc., Lowell T. Cage, Trustee v. GeoResources, Inc.) The bankruptcy trustee of a former leonardite customer, Ambar, Inc. (n/k/a Ramba, Inc.) has sued us for approximately $139,000 in an amended preference claim in Bankruptcy Court. Our defense has been vigorous, and the District Court is presently considering our Motion for Summary Judgment. See Note I to the Consolidated Financial Statements included herein under Item 7 for further information.

Except as discussed herein, we are not a party, nor are any of our properties subject, to any pending material legal proceedings. We know of no legal proceedings contemplated or threatened against us.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the fourth quarter of 2003, no matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our Common Stock trades on the Nasdaq SmallCap Stock Market under the Symbol "GEOI". The following table sets forth for the period indicated the lowest and highest trade prices for our Common Stock as reported by the Nasdaq SmallCap Stock Market. These trade prices may represent prices between dealers and do not include retail markups, markdowns or commissions.

		TRADE PRICE	
CALENDAR		HIGHEST	LOWEST
2003	4th Quarter	$2.61	$1.25
	3rd Quarter	$1.50	$1.25
	2nd Quarter	$1.49	$ .89
	1st Quarter	$1.83	$ .95
2002	4th Quarter	$1.38	$1.08
	3rd Quarter	$1.79	$1.07
	2nd Quarter	$1.94	$1.43
	1st Quarter	$1.69	$1.41

As of March 15, 2004, there were approximately 1,300 holders of record of our Common Stock. We believe that there are also approximately 850 additional beneficial owners of Common Stock held in "street name".

We have never declared or paid a cash dividend on our Common Stock nor do we anticipate that dividends will be paid in the near future. Further, certain of our financing agreements restrict the payment of cash dividends. See Note E to the Consolidated Financial Statements for further information.

Equity Compensation Plan Information

The following sets forth information as of March 15, 2004 concerning our compensation plan under which shares of our common stock are authorized for issuance.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	WEIGHTED AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE*
Equity compensation plans approved by security holders: 1993 Employees' Incentive Stock Option Plan	166,000	$2.34	-0-
Equity compensation plans not approved by security holders:	N/A	N/A	N/A

*The term of this plan expired on February 17, 2003. Thus, no further options may be granted under the plan. On March 2, 2004, the Board of Directors authorized the officers of the Company to prepare a 2004 Employees' Incentive Stock Option Plan and submit it to the shareholders for approval at the 2004 Annual Meeting of Shareholders.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OF PLAN OF OPERATION

OVERVIEW

We operate through three primary segments: 1) oil and gas exploration and production; 2) oil and gas drilling; and 3) leonardite mining and processing. Our oil and gas strategy is focused on the exploitation of existing oil and gas fields. Our drilling operations focus is development of our customer base and increasing our project capabilities. Our major leonardite products are oil and gas drilling mud additives. Our leonardite operations are also concentrated on the expansion of customers and products. See Note B to the Consolidated Financial Statements for financial information about our business segments.

BUSINESS ENVIRONMENT AND RISK FACTORS

This discussion and analysis of financial condition and results of operations, and other sections of this report, contain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are based on management's beliefs, assumptions, current expectations, estimates and projections about the oil and gas industry, the leonardite industry and the oil well drilling industry, the economy and about us. Words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or comparable words are intended to identify forward-looking statements. These statements are not guarantees of future performance and involve risks, uncertainties and assumptions that are difficult to predict with regard to timing, extent, likelihood and degree of occurrence. Therefore, our actual results and outcomes may materially differ from what may be expressed or forecasted in our forward-looking statements. Furthermore, we undertake no obligation to update, amend or clarify forward-looking statements; whether as a result of new information, future events or otherwise.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to, changes in production volumes; worldwide supply and demand which affect commodity prices for oil; the timing and extent of our success in discovering, acquiring, developing and producing oil, natural gas and leonardite reserves; risks inherent in the drilling and operation of oil and natural gas wells and the mining and processing of leonardite products; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; and conditions in the capital markets. See "Risk Factors" in Item 1 to this report.

CRITICAL ACCOUNTING POLICIES

Certain accounting policies are important to the portrayal of our consolidated financial condition and results of operations and require management's subjective or complex judgments. The policies are as follows:

Oil and Gas Properties

We employ the full cost method of accounting for our oil and gas production assets. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. The sum of net capitalized costs and estimated future development and dismantlement costs is depleted on the unit-of-production basis using proved oil and gas reserves as determined by independent petroleum engineers.

Reserve engineering is a subjective process that is dependent on the quality of available data and on engineering and geological interpretation and judgment. Reserve estimates are subject to change over time as additional information becomes available. If the estimate of proved reserve volumes declines or the estimate of future development costs increases, our depletion increases, which reduces our net income.

Also under the full cost method, we are required to record a permanent impairment provision if the net book value of our oil and gas properties less related deferred taxes exceeds a ceiling value equal to the present value of the future cash inflows from proved reserves, tax effected and discounted at 10%. The ceiling test is computed at the end of each quarter. The oil and gas prices used in calculating future cash inflows are based upon the market price on the last day of the accounting period. Oil and gas prices are generally volatile and if the market prices at a period end date have decreased, we may have to record an impairment. We have recorded impairments in the past as a result of low oil prices.

Revenue Recognition

Revenues are recognized when delivery of oil and gas production is made, leonardite is shipped and as drilling work progresses.

Impairment of Long-Lived Assets

Potential impairment of long-lived assets (other than oil and gas properties) is reviewed whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. No impairment losses have been recognized on long-lived assets.

Asset Retirement Obligation

If a reasonable estimate of the fair value can be made, we will record a liability for legal obligations associated with the future retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal operation of the assets.

The fair value of a liability for an asset retirement obligation is recognized in the period in which the liability is incurred. The fair value is measured using expected future cash outflows (estimated using current prices that are escalated by an assumed inflation rate) discounted at our credit-adjusted risk-free interest rate. The liability is then accreted each period until it is settled or the asset is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded. The initial fair value of the asset retirement obligation is capitalized and subsequently depreciated or amortized as part of the carrying amount of the related asset.

We have recorded asset retirement obligations related to our oil and gas properties. We have also identified other asset retirement obligations that are not recorded because a reasonable estimate of the fair value cannot be made due to the indeterminate life of the associated assets. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Accounting for Income Taxes

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes. This process involves estimating our current tax exposure together with assessing temporary differences resulting from the differing treatment of items for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our consolidated balance sheet. We regularly review our deferred tax assets for recoverability based on historical taxable income, projected future taxable income, and the expected timing of the reversals of existing temporary differences. To the extent we believe that recovery is not likely, we must establish a valuation allowance. We have recorded a valuation allowance due to uncertainties related to our ability to utilize some of our statutory depletion carryforward. After recognition of this allowance, our combined net deferred tax assets and deferred tax liabilities result in a net long-term liability. To the extent we increase or decrease the allowance in a period, we must include an expense or benefit within the tax provision in the statement of operations. Significant management judgment is required in determining our provision for income taxes, deferred tax assets and liabilities and the valuation allowance recorded against our deferred tax assets.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

NEW ACCOUNTING STANDARDS

In March 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities". SFAS 149 did not materially effect the financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity". SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. SFAS 150 did not materially effect the financial statements.

RESULTS OF OPERATIONS

The following table sets forth the selected financial data during the last five years.

	2003	2002	2001	2000	1999
Operating Revenue	$ 4,842,952	$ 3,987,686	$ 4,216,402	$ 5,325,378	$ 3,561,449
Net Income	446,563	91,374	41,818	1,414,797	481,552
Net Income Per Share	.12	.02	.01	.36	.12
<u>AT YEAR END:</u>					
Total Assets	11,584,273	9,048,200	8,201,719	7,450,286	7,328,840
Long-term Debt	1,599,479	1,910,228	1,035,228	375,000	1,610,008
Current Maturities	479,457	132,260	125,000	125,000	175,000
Working Capital (deficit)	(172,970)	310,516	(223,782)	423,897	638,549
Stockholders' Equity	5,973,886	5,616,211	5,536,009	5,712,655	4,462,475

Comparison of 2003 to 2002 Revenue, Costs and Gross Margin For Oil and Gas Operations

	Year 2003	% Increase (Decrease) From 2002	Year 2002	% Increase (Decrease) From 2001
Oil and gas production sold (BOE)	137,237	(3.5%)	142,197	(6.4%)
Average price per BOE	$ 26.34	25.7%	$ 20.96	3.9%
Oil and gas revenue	$ 3,614,592	21.3%	$ 2,980,228	(2.7%)
Production costs	$ 1,786,379	10.3%	$ 1,619,049	(12.8%)
Average production cost per BOE	$ 13.02	14.3%	$ 11.39	(6.9%)
Gross margin	$ 1,828,213	34.3%	$ 1,361,179	12.7%

The relative changes in revenue, production costs and gross margin for oil and gas operations in years ended 2003 and 2002 are shown in the chart above. The source of all of our oil and gas revenue is our sales of oil in 42 gallon barrels (abbreviated Bbl. a capacity established in the late 1800's from wooden barrels used for wine, beer, whiskey, fish and pickles) and gas in thousands of cubic feet at atmospheric conditions abbreviated MCF. We also convert gas to its approximate "oil equivalent" by its relative energy content of six MCF being equal to 1 Bbl of oil. During 2003, we slowed the moderate decline in our production to 3.5% but fell slightly short of our goal to increase production during the year because of a troublesome completion on our last drilling project for 2003. Our Anderson et. al. 3-24 went on production in the fourth quarter at a disappointing 1 barrel of oil per day ("BOPD") while all of our technical information indicated the well was structurally and stratigraphically equivalent to our Anderson et. al. 1-24 that had initial pump production of 83 BOPD and has recovered more than 140,000 Bbls of oil in the last 18 years. Our 3-24 well is a 40-acre offset to the 1-24 and continuing that completion, possibly with some relatively new stimulation technology, is a high priority. We do not believe the relatively small declines in our production for the last two years is a trend for the future. Our rate of decline has gotten smaller and we believe we can increase production with planned drilling and workover activity for 2004.

Although the production we sold was slightly less in 2003 compared to 2002, the average value of our sales was dramatically higher leading to a healthy increase in our oil and gas revenue. Revenue per BOE was consistently higher in 2003, always staying within a range between the high of $28.47 for the first quarter and the low of $24.37 for the second quarter. This is a sharp contrast to 2002 when average oil revenue per barrel was $4 to $12 lower than 2003 in the first and second quarters and $2 to $3 lower in the third and fourth quarters. Oil and gas prices are the single most important aspect of our operating performance and financial results. While the oil and gas business and accounting principles used are both highly complex, the price of the commodities we sell affects every facet of our operations.

Oil and gas production costs increased 10% in 2003, some of which is a natural extension of the higher oil and gas revenues, as production taxes are an "ad valorem" tax, a straight percentage of value produced at the wellhead. In 2003, $31,000 of the $167,000 increase in production costs was due to taxes. In addition with higher oil prices our expenses were generally higher in many categories, particularly work-over activity; and 2003 was also our first full year of participation in a secondary recovery unit operated by another company. Increased production costs attributable to these last two factors resulted in a net increase of about $60,000. Finally, 2003 was our first year of accounting for long-lived asset retirement obligations under SFAS 143. The accretion expense related to that accounting change increased production costs by approximately $76,000 (See Note F).

The combination of slightly lower production and modestly higher production costs resulted in 2003 average production cost per barrel increasing about 14% over 2002. Production costs and costs per BOE are one of the few financial areas we can control to a material degree. Revenue can be hedged, but usually only for relative short periods of time. Unit costs and total costs can be "controllable" over and above fixed costs by discretion in the amount of down-hole and surface maintenance work to be performed. These decisions are driven by the spread between per unit revenue and costs. That difference was $13.32 in 2003 and $9.57 in 2002. Therefore, although per Bbl costs increased 14% in 2003, we believe it is at least partly due to the fact that the higher per Bbl revenue allowed us to increase discretionary spending, and that those discretionary costs could be reduced some if oil prices decrease. Discretionary costs have limitations however, as many oil and gas production costs are fixed costs, or fixed costs per Bbl. Our three largest costs are contract labor, fuel and power, and oil treating chemicals. In 2003 and 2002, just those costs expressed on a per Bbl basis were $4.96 and $4.79, respectively. These do not represent a minimum production cost as some level of maintenance is required to keep wells producing and several other smaller costs such as taxes are also unavoidable. The accretion expense associated with SFAS 143 discussed above also increased 2003 per Bbl production costs by $0.56 over 2002 when that expense was not recognized.

As a result of our revenue and expenses for 2002 and 2003, our gross margin for the oil and gas segment of our operations increased in each year when compared to the year prior. This gross margin does not include any expenses for non-cash items such as depletion or any corporate costs such as selling, general and administrative.

Looking forward, we expect 2004 to be a year of significant activity for the industry and us. We have one drilling permit remaining from an un-drilled well we had budgeted for 2003 and a new permit granted in March 2004. The first well that will be drilled is a development well in our Landa Field in Bottineau County, ND. Our subsidiary's drilling rig has already been transported to this location in anticipation of our drilling plans, and we expect to spud this well in early April. We are the operator and 75% working interest owner of this project. In addition to drilling planned for this year, we hope to form another new unit for the purpose of secondary recovery by water-flood, and perform a significant amount of work-over and other remedial work intended to increase our production. We believe many oil and gas operating companies intend to increase their exploration and production activities in the near future which may strain the availability of oil and gas related labor, equipment and services. For instance, recently enacted steel tariffs, and declining supply from foreign sources, is increasing steel prices and may cause shortages which would likely negatively impact our operations and financial results since oil and gas exploration and production is heavily reliant on steel products. We intend to work diligently towards accomplishing our 2004 goals and beyond. However, considering the competitive environment and global events, we are cautious about our ability to reach our goals.

Comparison of 2003 to 2002 Revenue, Costs and Gross Margin For Drilling Operations

	Year 2003	% Increase (Decrease) From 2002	Year 2002	% Increase (Decrease) From 2001
Operating days	56.2	55.2%	36.2	--
Drilling revenue	$ 406,141	44.8%	$ 280,538	--
Average revenue per day	$ 7,227	(6.7%)	$ 7,750	--
Drilling Costs	$ 369,869	55.6%	$ 237,729	--
Average costs per day	$ 6,581	--%	$ 6,567	--
Gross margin	$ 36,272	(15.3%)	$ 42,809	--

Our oil and gas drilling subsidiary, Western Star Drilling Company, ("WSDC") commenced operations January 2, 2002, and therefore there are no percentage changes for 2002 compared to the prior year. All the amounts in the table above are presented in conformance with our financial statements and accordingly represent only drilling operations for other companies. The operating days with GeoResources' drilling included was 85 in 2003 and 55.1 in 2002. During 2003, drilling operations consisted of three wells for us and two wells for other operators, for a total of five wells with footage of 20,122. This compares to five drilled in 2002 of which two were drilled for us and three for other operators, with footage of 20,476. One of the 2003 wells had a total depth of just less than 7,000 feet, which is the deepest well WSDC has drilled to date.

The increased level of outside drilling operations has met our expectations for these first formative years. The level of shallower drilling in the Williston Basin has not kept pace with deeper vertical and horizontal drilling, but we believe it will as more of the typically smaller operators in the region begin to gain confidence in higher oil prices. Although the drilling rig was substantially below full utilization in 2003, we believe it takes some time to build a customer base and demonstrate the rig's capabilities. WSDC is still a new business start-up, and a positive gross margin in its first two years we feel is an accomplishment in itself.

Revenue per day was essentially stable in both years; however, 2003 had 55% more operating days due to the deeper well mentioned above that resulted in 45% more total revenue. Average revenue per day is less than the contract day-work rate, because operating days includes days for "move in, rig up" and "tear out, rig down" days. These days are billed at substantially lower rates than drilling days. Also, drilling contracts can be structured in several different formats including day-work, turnkey and footage. As a result of revenue and costs, WSDC had comparable gross margins in both years. Because WSDC has value to us over and above its financial profit potential, our primary goal in these first few years is that the subsidiary has a positive gross margin and cash flow. When depreciation is taken into account for WSDC, neither year contributed to our net income. Also, any cash flow from drilling operations may be re-invested into the drilling equipment to expand WSDC's project capabilities.

Comparison of 2003 to 2002 Revenue, Costs and Gross Margin For Leonardite Operations

	Year 2003	% Increase (Decrease) From 2002	Year 2002	% Increase (Decrease) From 2001
Leonardite sold (Tons)	6,558	0.7%	6,511	(33.4%)
Average price	$ 125.38	12.3%	$ 111.64	(5.3%)
Leonardite revenue	$ 822,219	13.1%	$ 726,920	(36.9%)
Production costs	$ 850,373	17.0%	$ 726,552	(31.7%)
Average production costs per ton	$ 129.67	16.2%	$ 111.59	2.7%
Gross margin (deficit)	$ (28,154)	(7,000+%)	$ 368	(100%)

Leonardite revenue and production costs are both greater than the amount presented in previous years due to an accounting reclassification of our invoicing of customers for shipping and packaging costs. Leonardite product sales were $822,000 in 2003 compared to $727,000 in 2002, an increase of $95,000 or 13.1%. This difference was due to drilling activity in the Gulf of Mexico. Production sold in 2003 was 6,558 tons at an average price of $125.38 compared to 6,511 tons at an average price of $111.64 for 2002.

Cost of leonardite sold was $850,000 in 2003 compared to $727,000 in 2002, an increase of $123,000 or 17.0%. Average production costs per ton were $129.67 and $111.59 for 2003 and 2002, respectively. A major part of the increase was attributable to substantially higher prices for natural gas. Costs per ton increased approximately 16.2% for 2003 compared to 2002 due mainly again to the increase in the price of natural gas.

Gross margin for 2003 leonardite operations before deductions for depreciation and selling, general and administrative expenses was a deficit of $28,154 compared to a break-even point for 2002. The $28,500 decrease in 2003 gross margin was a result of the higher costs discussed above. Our sales are primarily tied to the off shore drilling needs for the deep wells. If drilling in the Gulf increases, our sales should increase also.

At year-end 2003, our plant manager retired after over 30 years of dedicated service to our company. A new plant manager was hired in-house with the remaining employees sharing more duties to eliminate hiring another person. We believe this plan will help reduce our costs in the future.

Comparison of 2003 to 2002 Consolidated Analysis of the Financial Statements

	Year 2003	% Increase (Decrease) From 2002	Year 2002	% Increase (Decrease) From 2001
Total operating revenue	$ 4,842,952	21.4%	$ 3,987,686	(5.4%)
Cost of operations	$ 3,006,621	16.4%	$ 2,583,330	(11.5%)
Total gross margin	$ 1,836,331	30.8%	$ 1,404,356	8.3%
Depreciation, depletion and amortization	$ 759,907	9.0%	$ 696,857	(6.4%)
Selling, general and administrative	$ 537,141	(1.5%)	$ 545,368	15.7%
Operating income	$ 539,283	232.6%	$ 162,131	100.2%
Nonoperating expenses	$ (57,172)	(12.1%)	$ (65,045)	2,896.1%
Income before taxes	$ 482,111	396.6%	$ 97,086	23.2%
Income taxes	$ 12,548	119.7%	$ 5,712	(84.6%)
Effect of change in accounting principle	$ (23,000)	--	--	--
Net income	$ 446,563	388.7%	$ 91,374	118.5%

Oil and gas depletion in 2003 was $566,084, or 6% higher than 2002, due to the implementation of SFAS 143. Leonardite depreciation in 2003 was $99,478 or 4% lower than 2002 due to the older equipment becoming fully depreciated. Drilling rig depreciation in 2003 was $59,133, or 60% higher due to the increased number of days the rig was utilized. Depreciation on general corporate assets in 2003 was $35,212, or 65% higher than 2002. General corporate depreciation includes our office building, equipment and the amortization of the Reymert property. The increase in this depreciation category is attributed to Reymert, which we started to amortize in 2003.

Selling, general and administrative costs (SG&A) were lower in 2003 due in part to a $50,000 reserve established in 2002 for a claim by a bankruptcy trustee of a former leonardite customer. See Note I to the Financial Statements for further information.

Income tax expense for each year is primarily reflective of changes in our tax-deferred assets and liabilities under the provisions of SFAS No. 109. See Notes A and G to the Financial statements for further information. The $23,000 charge for an accounting change is entirely due to our adoption of SFAS 143. See Note F to the Financial Statements for further information.

As a result of all the factors discussed above, net income before cumulative effect of change in accounting principle for 2003 was $470,000 or $0.13 per share compared to a net income of $91,000 or $0.02 per share in 2002.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2003, we had current assets of $1,697,000 compared to current liabilities of $1,870,000 for a current ratio of .91 to 1 and a working capital deficit of $173,000. This compares to a current ratio of 1.28 to 1 at December 31, 2002, and working capital of $311,000. As in past years when oil and gas prices have been favorable, we take advantage of the increased cash flow to make larger investments in drilling and field maintenance activities as described below. These additional expenditures accounted for our reduction in working capital in 2003 compared to 2002. Due to these higher investments, we were not in compliance with a working capital covenant with our bank. However, that non-compliance was waived in writing by the bank shortly after year-end.

During the year ended December 31, 2003, we generated cash flows from operating activities of $1,183,000, which was $358,000 more than the amount generated during 2002. This increase was essentially due to higher oil prices discussed previously. We anticipate that cash flows from operations and funds available under our $3,000,000 revolving line of credit ("RLOC") will be sufficient to meet our short-term cash requirements. The RLOC, which had an available balance of $925,000 at December 31, 2003, allowed borrowing until January 5, 2004, with repayment due by January 5, 2008. Since year-end, we have reached verbal agreement with our bank to establish a similar $3,000,000 RLOC. The 2004 RLOC will allow borrowings until March 5, 2007, with repayment due by March 5, 2011.

During 2003, our investing activities used $1,131,000 of cash for additions to property, plant and equipment. Approximately $601,000 of these additions were to drill three wells in Bottineau County, North Dakota: one in our South Starbuck Madison Unit, one in the Leonard Field and one exploratory well. We also used approximately $354,000 for capitalized workovers on operated and non-operated wells. Portions of the remaining $173,000 used in investing activities consisted of $99,000 of additional rig equipment, $19,000 for miscellaneous office and leonardite plant expenditures, $32,000 for unproved oil and gas property costs and $26,000 for proved property acquisition costs.

During 2003, our financing activities consisted of $128,000 of cash utilized for regularly scheduled principal payments under long-term debt agreements plus an additional $135,000 to pay off our 1997 oil and gas loan. We also used an additional $89,000 of cash to purchase our common stock on the open market. During the fourth quarter of 2003, we borrowed $300,000 on our RLOC to finance our workover program and to consolidate our loans.

We estimate that our capital costs for 2004 relating to our proved developed nonproducing and proved undeveloped oil and gas properties will be approximately $1,000,000. Planned expenditures for 2004 also include delay rentals and other exploration costs of approximately $100,000. Funds expected to be used for 2004 principal payments on our 2001 Oil and Gas loan are $476,000.

We expect to continue to evaluate possible future purchases of additional producing oil and gas properties and the further development of our properties. We believe our long-term cash requirements for such investing activities and the repayment of long-term debt can be met by future cash flows from operations and, if necessary, possible forward sales of oil reserves or additional debt or equity financing.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See "Index to Consolidated Financial Statements" on page 35.

ITEM 8. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

Not applicable.

ITEM 8A. CONTROLS AND PROCEDURES

We carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in our Exchange Act reports was recorded, processed, summarized and reported within the applicable time periods. There have been no significant changes to our internal controls or, to our knowledge, in other factors that could significantly affect these controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTER AND CONTROL PERSONS; COMPLIANCE WITH SECTION 16(a) OF THE EXCHANGE ACT

The following sets forth certain information concerning each of our directors and executive officers:

NAME AND AGE	POSITION(S) WITH THE COMPANY	PERIOD OF SERVICE AS A DIRECTOR OR OFFICER
Jeffrey P. Vickers Age: 51	President and Director	Since 1982
Jeffrey B. Jennings Age: 47	Vice President of Land and Finance	Since June 2000
Cathy Kruse Age: 49	Secretary and Director	Since October 1981 (officer); and since June 1996 (director)
Connie R. Hval Age: 43	Treasurer	Since June 2000
H. Dennis Hoffelt Age: 62	Director Member of Audit Committee	From 1967 through June 1986; and since June 1987

NAME AND AGE	POSITION(S) WITH THE COMPANY	PERIOD OF SERVICE AS A DIRECTOR OR OFFICER
Paul A. Krile Age: 75	Director Member of Audit Committee	Since June 1997
Nick Voller Age: 53	Director Member of Audit Committee	Since March 2004
Duane Ashley Age: 55	Director	Since June 1999

All of the directors' terms expire at the next annual meeting of shareholders or when their successors have been elected and qualified. Our executive officers serve at the discretion of the Board of Directors. The Board of Directors has appointed an audit committee consisting of three independent directors who are financial experts, Nick Voller, H. Dennis Hoffelt and Paul A. Krile.

Jeffrey P. Vickers received a Bachelor of Science degree in Geological Engineering with a Petroleum Engineering option from the University of North Dakota in 1978. In 1979, Mr. Vickers joined Amerada Hess Corporation as an Associate Petroleum Engineer in the Williston Basin. In 1981, Mr. Vickers was employed by us as our Drilling and Production Manager where he was responsible for providing technical assistance and supervision of drilling and production operations and generated development drilling programs. He became our President on January 1, 1983. In June 1982, Mr. Vickers became a director.

Jeffrey B. Jennings is Vice President of Land and Finance. Mr. Jennings received a Bachelor of Science in Geological Engineering in 1980 and a Master of Science in Mineral Economics in 1992, from the Colorado School of Mines. He was a consultant for us for two years prior to his employment with us in January 1996.

Cathy Kruse is our Secretary and business office manager. Ms. Kruse graduated from the Atlanta College of Business in 1977 and was employed as a Legal Assistant for four years prior to her employment with us in May 1981. In June 1996, Ms. Kruse became a director.

Connie R. Hval is our Treasurer and comptroller. Ms. Hval graduated from the University of North Dakota – Williston in December 1980 and became employed with us in January 1981.

H. Dennis Hoffelt is retired. Prior to his retirement Mr. Hoffelt was President of Triangle Electric Inc., Williston, North Dakota, an electrical contracting firm, for over thirty years. He served as one of our directors from 1967 through June of 1986 and was elected as a director again in 1987.

Paul A. Krile has been one of our directors since June 1997. He has been the President and owner of Ranco Fertiservice, a manufacturer of dry fertilizer handling equipment, headquartered in Sioux Rapids, Iowa for more than the last five years.

Nick Voller has been one of our directors since March 2004. For the past five years, he has been a partner with Voller Brakey Stillwell & Suess, PC a CPA firm located in Williston, ND.

Duane Ashley has been one of our directors since June 1999. He has been a Senior Salesman for GRACO Fishing and Rental Tool, Inc. and Weatherford Enterra Inc. for the past five years.

Cathy Kruse is the sister-in-law of Jeffrey P. Vickers. No other family relationship exists between or among any of the officers or nominees. There are no arrangements or understandings between any of the directors or nominees and any other person pursuant to which any person was or is to be elected as a director or nominee.

Code of Ethics

Our Board of Directors has adopted a Code of Business Conduct and Ethics ("Code"), a copy of which we have filed as exhibit 14.1 to this report.

Our Code provides general statements of our expectations regarding ethical standards that we expect our directors, officers and employees to adhere to while acting on our behalf. Among other things, the Code provides that:

- we will comply with all laws, rules and regulations;
- our directors, officers and employees are to avoid conflicts of interest and are prohibited from competing with us or personally exploiting our corporate opportunities; pressure or irregularities in geological formations;
- our directors, officers and employees are to protect our assets and maintain our confidentiality;
- we are committed to promoting values of integrity and fair dealing; and
- we are committed to accurately maintaining our accounting records under generally accepted accounting principles and timely filing our periodic reports.

Our Code also contains procedures for our employees to report, anonymously or otherwise, violations of the Code.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers, and persons who own more than 10% of our common stock to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of our common stock. Executive officers, directors and greater than 10% shareholders are required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. To our knowledge, based solely on review of the copies of such reports furnished to us or advice that no filings were required during fiscal year 2003, all executive officers, directors and greater than 10% beneficial owners complied with the Section 16(a) filing requirements.

ITEM 10. EXECUTIVE COMPENSATION

The following table presents the aggregate compensation which was earned by our Chief Executive Officer for each of the past three years. We do not have an employment contract with any of our executive officers. None of our employees earned total annual salary and bonus in excess of $100,000. There has been no compensation awarded to, earned by or paid to any employee required to be reported in any table or column in any fiscal year covered by any table, other than what is set forth in the following table.

Summary Compensation Table

					Long Term Compensation			
	Annual Compensation				Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compen-sation	Restricted Stock Award(s) ($)	Securities Underlying Options SARs(#)	LTIP Payouts ($)	All Other Compen-sation ($)
Jeffrey P. Vickers CEO	2003	$91,700	-0-	-0-	N/A	-0-	N/A	$ 9,250
	2002	$90,849	-0-	-0-	N/A	-0-	N/A	$ 4,542
	2001	$90,579	-0-	-0-	N/A	-0-	N/A	$ 4,529

In the preceding table, the column titled "All Other Compensation" is comprised entirely of profit sharing amounts and the 401(k) Company matching funds discussed below.

If we achieve net income in a fiscal year, our Board of Directors may determine to contribute an amount based on our profits to the Employees' Profit Sharing Plan and Trust (the "Profit Sharing Plan"). An eligible employee may be allocated from 0% to 15% of his other compensation depending upon the total contribution to the Profit Sharing Plan. A total of 20% of the amount allocated to an individual vests after three years of service, 40% after four years, 60% after five years, 80% after six years and 100% after seven or more years. On retirement, an employee is eligible to receive the vested amount. On death, 100% of the amount allocated to an individual is payable to the employee's beneficiary. We made total contributions to the Profit Sharing Plan, matching and discretionary, for the years ended December 31, 2003, 2002 and 2001 of $49,570, $26,019, and $24,614, respectively. As of December 31, 2003, vested amounts in the Profit Sharing Plan for all officers as a group was approximately $358,557.

Effective July 1, 1997, we executed an Adoption Agreement Nonstandardized Code 401(k) Profit Sharing Plan that incorporated a 401(k) Plan into the existing Profit Sharing Plan. This retirement plan was amended and updated to comply with legislative changes effective September 30, 2003. Eligible employees are allowed to defer up to 15% of their compensation and we match up to 5%.

Our 1993 Employees' Incentive Stock Option Plan (the "Plan") expired in 2003. Nonetheless, all options outstanding at that time remain outstanding and exercisable until they expire pursuant to their terms.

If within the duration of any outstanding option, there is a corporate merger consolidation, acquisition of assets or other reorganization and if this transaction affects the optioned stock, the optionee will thereafter be entitled to receive upon exercise of his option those shares or securities that he would have received had the option been exercised prior to the transaction and the optionee had been a stockholder with respect to such shares.

A total of 300,000 shares were reserved for issuance under the Plan. Of the 300,000 reserved shares, options for 166,000 shares remain outstanding at an average exercise price of $2.34. No grants of stock options were made by us during the fiscal year ended December 31, 2003.

We intend to present a new stock incentive plan for approval by our shareholders at our 2004 Annual Meeting of Shareholders.

Aggregated Option Exercises In Last Fiscal Year and Fiscal Year-End Option Values

The following table summarizes for our Chief Executive Officer (i) the total number of shares received upon exercise of stock options during the fiscal year ended December 31, 2003, (ii) the aggregate dollar value realized upon such exercise, (iii) the total number of unexercised options, if any, held at December 31, 2003, and (iv) the value of unexercised in-the-money options, if any, held at December 31, 2003.

In-the-money options are options where the fair market value of the underlying securities exceeds the exercise or base price of the option. The aggregate value realized upon exercise of a stock option is the difference between the aggregate exercise price of the option and the fair market value of the underlying stock on the date of exercise. The value of unexercised, in-the-money options at fiscal year-end is the difference between the exercise price of the option and the fair market value of the underlying stock on December 31, 2003, which was $2.48 per share. With respect to unexercised, in-the-money options, the underlying options have not been exercised, and actual gains, if any, on exercise will depend on the value of our Common Stock on the date of exercise.

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED($)	NUMBER OF UNEXERCISED OPTIONS/SARS AT FY-END(#) EXERCISABLE/ UNEXERCISABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARS AT FY-END EXERCISABLE/ UNEXERCISABLE
Jeffrey P. Vickers, CEO	-0-	-0-	71,000/0	$ 9,970/0

Directors' Compensation

We pay each director who is not also an employee $200 per month and reimburse the directors for travel expenses. Each director who is also on the audit committee receives an additional $100 per month.

ITEM 11. SECURITIES OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth the number of shares of our Common Stock beneficially owned by each of our officers and directors and by all directors and officers as a group, as of March 15, 2004. Unless otherwise indicated, the shareholders listed in the table have sole voting and investment powers with respect to the shares indicated.

CLASS OF SECURITIES	NAME AND ADDRESS OF BENEFICIAL OWNER	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Jeffrey P. Vickers 1814 14th Ave. W. Williston, ND 58801	331,934-Direct and Indirect(a)	8.9%
Common Stock, $.01 par value	Paul A. Krile P. O. Box 329 Sioux Rapids, IA 50585	253,000-Direct	6.8%
Common Stock, $.01 par value	Cathy Kruse 723 W. 14th St. Williston, ND 58801	9,700-Direct(c)	(b)
Common Stock, $.01 par value	H. Dennis Hoffelt 9421 E. Desert Lake Sun Lakes, AZ 85248	41,000-Direct and Indirect(d)	1.1%
Common Stock, $.01 par value	Connie R. Hval 7400 3rd Ave. E. Williston, ND 58801	9,500-Direct(e)	(b)
Common Stock, $.01 par value	Jeffrey B. Jennings 1410 1st Ave. W. Williston, ND 58801	10,500-Direct(f)	(b)
Common Stock, $.01 par value	Duane Ashley 910 15th St. W. Williston, ND 58801	--	--
Common Stock, $.01 par value	Nick Voller 222 University Ave. Williston, ND 58801	--	--
Common Stock, $.01 par value	Officers and Directors as a Group- (eight persons)	655,634-Direct and Indirect	17.6%

(a) Includes 139,634 shares owned directly by Mr. Vickers, 2,500 in a self-directed individual retirement account, 72,000 shares held jointly with his wife, Nancy J. Vickers, 25,500 shares held directly by his wife, 1,300 shares in his wife's self-directed individual retirement account, and an aggregate 20,000 shares held by him as custodian for his children. Also included are 71,000 shares that may be purchased by Mr. Vickers under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(b) Less than 1%.

(c) Included are 9,500 shares which may be purchased by Ms. Kruse under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(d) Mr. Hoffelt has sole voting and investment power over 11,500 of shares and has shared voting and investment powers over the remaining 29,500 shares.

(e) Included are 9,500 shares which may be purchased by Ms. Hval under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(f) Included are 9,500 shares which may be purchased by Mr. Jennings under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

The following table sets forth information concerning persons other than our officers or directors known to us to be the beneficial owners of more than 5% of our outstanding Common Stock as of March 15, 2004.

CLASS OF SECURITIES	NAME AND ADDRESS OF PERSON	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Joseph V. Montalban P. O. Box 200 Cut Bank, MT 59427	342,700-Direct and Indirect(a)(b)	9.2%

(a) This information was obtained from our transfer agent, Wells Fargo Bank Minnesota, N.A., on March 25, 2004, and the Depository Trust Company's non-objecting beneficial owners' list dated December 31, 2003.

(b) Includes 107,000 shares owned by Montalban Oil & Gas Operations (MOGO Inc.)

We are not aware of any arrangements which could, at a subsequent date, result in a change in control of the company.

ITEM 12. <u>CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS</u>

There are no transactions or series of similar transactions since the beginning of our last fiscal year or any currently proposed transaction or series of similar transactions to which we were or are to be a party, and which the amount involved exceeds $10,000 and in which any director, executive officer, principal shareholder or any member of their immediate family had or will have a direct or indirect material interest.

PART IV

ITEM 13. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) Documents filed as Part of this Report

(1) Financial Statements and Schedules. See "Index to Consolidated Financial Statements" on next page. There are no financial statement schedules filed herewith.

(2) Exhibits See "Exhibit Index" on page 62.

(b) Reports on Form 8-K
On November 19, 2003, we filed our earnings press release for the third quarter of 2003 under Item 12 of Form 8-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

During 2003 and 2002, we paid the following fees to our principal accountants:

	2003	2002
Audit Fees	$ 24,300	$ 23,150
Audit Related Fees	1,476	1,312
Tax Fees	4,487	4,276
All Other Fees (1)	4,250	2,100
	$ 34,513	$ 30,838

(1) Services relating to review of our Quarterly Reports on Form 10-QSB and SFAS 143 research

To help assure independence of the independent auditors, the Audit committee has established a policy whereby all audit, review, attest and non-audit engagements of the principal auditor or other firms must be approved in advance by the Audit Committee; provided, however, that de minimis non-audit services may instead be approved in accordance with applicable Securities and Exchange Commission rules. This policy is set forth in our Audit Committee charter, a copy of which will be included with our proxy statement for our 2004 Annual Meeting of Shareholders. Of the fees shown in the table which were paid to our principal accountants in 2003, 78% were approved by the Audit Committee. SEC regulations and company policy did not require pre-approval for non-audit services prior to 2003.

GEORESOURCES, INC., AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS ON THE CONSOLIDATED FINANCIAL STATEMENTS

To the Board of Directors and Shareholders
GeoResources, Inc.

We have audited the accompanying consolidated balance sheets of GeoResources, Inc., and Subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2003, 2002 and 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits 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 GeoResources, Inc., and Subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years ended December 31, 2003, 2002 and 2001, in conformity with accounting principles generally accepted in the United States of America.

/s/ Richey, May & Co., LLP
Englewood, Colorado
February 20, 2004

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2003 AND 2002

ASSETS

	2003	2002
CURRENT ASSETS:		
Cash and equivalents	$ 343,419	$ 329,302
Trade receivables, net	1,084,678	821,459
Inventories	233,306	207,998
Income tax receivable	--	50,192
Prepaid expenses	35,335	28,326
Total current assets	1,696,738	1,437,277
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Properties being amortized	24,711,298	22,636,316
Properties not subject to amortization	280,565	251,714
Drilling rig and equipment	1,176,940	1,077,551
Leonardite plant and equipment	3,267,634	3,262,200
Other	756,211	757,431
	30,192,648	27,985,212
Less accumulated depreciation, depletion, amortization and impairment	(20,310,113)	(20,386,789)
Net property, plant and equipment	9,882,535	7,598,423
OTHER ASSETS	5,000	12,500
TOTAL ASSETS	$ 11,584,273	$ 9,048,200

LIABILITIES AND STOCKHOLDERS' EQUITY

	2003	2002
CURRENT LIABILITIES:		
Accounts payable	$ 985,766	$ 659,282
Accrued expenses	404,485	335,219
Current maturities of long-term debt	479,457	132,260
Total current liabilities	1,869,708	1,126,761
LONG-TERM DEBT, less current maturities	1,599,479	1,910,228
ASSET RETIREMENT OBLIGATIONS	1,735,200	--
DEFERRED INCOME TAXES	406,000	395,000
Total liabilities	5,610,387	3,431,989
CONTINGENCIES (NOTE H)		
STOCKHOLDERS' EQUITY:		
Common stock, par value $.01 per share; authorized 10,000,000 shares; issued and outstanding, 3,723,977 and 3,787,477 shares, respectively	37,240	37,875
Additional paid-in capital	295,932	384,185
Retained earnings	5,640,714	5,194,151
Total stockholders' equity	5,973,886	5,616,211
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 11,584,273	$ 9,048,200

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

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	2003	2002	2001
OPERATING REVENUES:			
Oil and gas	$ 3,614,592	$ 2,980,228	$ 3,064,135
Leonardite	822,219	726,920	1,152,267
Drilling	406,141	280,538	--
	4,842,952	3,987,686	4,216,402
OPERATING COSTS AND EXPENSES:			
Oil and gas production	1,786,379	1,619,049	1,856,159
Cost of leonardite sold	850,373	726,552	1,062,995
Drilling costs	369,869	237,729	--
Depreciation, depletion and amortization	759,907	696,857	744,742
Selling, general and administrative	537,141	545,368	471,517
	4,303,669	3,825,555	4,135,413
Operating income	539,283	162,131	80,989
OTHER INCOME (EXPENSE):			
Interest expense	(84,432)	(95,635)	(44,834)
Interest income	8,362	11,635	20,294
Other income and losses, net	18,898	18,955	22,369
	(57,172)	(65,045)	(2,171)
Income before income taxes	482,111	97,086	78,818
INCOME TAX EXPENSE	12,548	5,712	37,000
Income before cumulative effect of change in accounting principle	469,563	91,374	41,818
Cumulative effect on prior years accounting change, net of tax	(23,000)	--	--
Net income	$ 446,563	$ 91,374	$ 41,818
EARNINGS PER SHARE:			
Income before cumulative effect of accounting change	$ .13	$ .02	$ .01
Cumulative effect of accounting change	(.01)	--	--
Net income, basic and diluted	$ .12	$ .02	$ .01
Weighted average number of shares outstanding	3,748,396	3,787,750	3,846,176
Dilutive potential shares – Stock options	--	--	--
Adjusted weighted average shares	3,748,396	3,787,750	3,846,176

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

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	Common Stock		Additional Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance, December 31, 2000	3,912,502	$ 39,125	$ 612,571	$ 5,060,959	$ 5,712,655
Issuance of common stock	1,000	10	1,990	--	2,000
Purchase of common stock	(119,275)	(1,193)	(219,271)	--	(220,464)
Net income	--	--	--	41,818	41,818
Balance, December 31, 2001	3,794,227	37,942	395,290	5,102,777	5,536,009
Purchase of common stock	(6,750)	(67)	(11,105)	--	(11,172)
Net income	--	--	--	91,374	91,374
Balance, December 31, 2002	3,787,477	37,875	384,185	5,194,151	5,616,211
Purchase of common stock	(63,500)	(635)	(88,253)	--	(88,888)
Net income	--	--	--	446,563	446,563
Balance, December 31, 2003	3,723,977	$ 37,240	$ 295,932	$ 5,640,714	$ 5,973,886

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

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 446,563	$ 91,374	$ 41,818
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and valuation allowance	759,907	696,857	744,742
Cumulative effect of accounting change	23,000	--	--
Accretion of asset retirement obligations	76,200	--	--
Deferred income taxes	15,000	51,000	60,000
Other	8,952	10,618	34,107
Changes in assets and liabilities:			
Decrease (increase) in:			
Trade receivables	(263,219)	(195,100)	296,814
Inventories	(25,308)	(11,140)	51,647
Income taxes receivable	50,192	(27,192)	(23,000)
Prepaid expenses and other	(7,009)	(3,171)	(9,496)
Increase (decrease) in:			
Accounts payable	29,438	99,512	40,827
Income taxes payable	--	--	(75,000)
Accrued expenses	69,266	112,544	29,953
Cash provided by operating activities	1,182,982	825,302	1,192,412
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(1,130,897)	(1,558,416)	(1,844,360)
Proceeds from sale of property, plant and equipment	14,472	--	--
Collection of mortgage loans receivable	--	--	103,321
Cash used in investing activities	(1,116,425)	(1,558,416)	(1,741,039)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	300,000	1,010,000	775,000
Principal payments on long-term debt	(263,552)	(127,740)	(114,772)
Cost to purchase common stock	(88,888)	(11,172)	(220,464)
Debt issue costs	--	--	(15,000)
Cash provided by (used in) financing activities	(52,440)	871,088	424,764
INCREASE (DECREASE) IN CASH AND EQUIVALENTS	14,117	137,974	(123,863)
CASH AND EQUIVALENTS, beginning of year	329,302	191,328	315,191
CASH AND EQUIVALENTS, end of year	$ 343,419	$ 329,302	$ 191,328

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

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	2003	2002	2001
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid (received) for:			
Interest	$ 87,477	$ 91,512	$ 45,365
Income taxes (refunds)	(52,644)	(18,096)	73,400

NONCASH INVESTING AND FINANCING ACTIVITIES

During 2001, the Company issued 1,000 shares of common stock valued at $2,000 as partial payment of damage compensation on a gas property.

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

A. SIGNIFICANT ACCOUNTING POLICIES:

Nature of Operations and Principles of Consolidation
The accompanying consolidated financial statements include the accounts of GeoResources, Inc., its wholly owned subsidiary, Western Star Drilling Company ("WSDC") and its 85% owned subsidiary, Belmont Natural Resource Company, Inc. ("BNRC"). All material intercompany transactions and balances between the entities have been eliminated. The minority interest in BNRC at December 31, 2003 and 2002 is zero.

GeoResources, Inc. (the "Company") is primarily involved in oil and gas exploration, development and production in North Dakota and Montana and the mining of leonardite and manufacturing of leonardite products in North Dakota to be sold to customers located primarily in the Gulf of Mexico coastal areas. BNRC was incorporated in 1991 to exploit natural gas opportunities in the Pacific Northwest. All properties of the Company and BNRC are located in the United States.

During the third quarter of 2001, the Company purchased a used drilling rig. The rig was reconditioned by the Company and commenced drilling operations in January 2002. Also in January 2002, WSDC was incorporated. In exchange for 100% of WSDC's outstanding common stock, the Company transferred the rig and all related equipment to WSDC. WSDC provides contract oil and gas drilling services to the Company and other operators in the Williston Basin area of North Dakota.

Reclassifications
Certain accounts in the prior-year financial statements have been reclassified for comparative purposes to conform with the presentation in the current-year financial statements.

Use of Estimates
The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates used in preparing these financial statements include the unaudited quantity of oil and gas reserves which directly affects the computation of depletion of oil and gas properties. It is at least reasonably possible that the estimates used will change within the next year.

Cash Equivalents
For purposes of the statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. The Company periodically maintains cash balances in financial institutions in excess of FDIC limits. The Company evaluates the credit worthiness of these financial institutions in determining the risk associated with these deposits.

Inventories
Inventories are stated at the lower of cost (first-in, first-out method) or market. The cost of crude oil inventory is comprised of lease operating expense and depreciation, depletion and amortization. The cost of leonardite inventories is comprised of direct mining and processing costs including labor costs, plant operating costs, additives and supplies, and depreciation.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with the acquisition, exploration and development of oil and gas reserves (including costs of abandoned leaseholds, delay lease rentals, dry hole costs, geological and geophysical costs, certain internal costs associated directly with acquisition, drilling and well equipment inventory, exploration and development activities, estimated dismantlement and abandonment costs, site restoration and environmental exit costs, etc.) are capitalized.

All capitalized costs of oil and gas properties, net of estimated salvage values, plus the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. The Company's oil and gas depreciation, depletion and amortization rate per equivalent barrel of oil produced was $4.12, $3.76, and $4.07 for 2003, 2002, and 2001, respectively.

In addition, the capitalized costs are subject to a "ceiling test" which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate, of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. As a result of this ceiling test, the Company had no write-downs of its oil and gas properties during 2003, 2002 or 2001.

Gains or losses are not recognized upon the sale or other disposition of oil and gas properties, except in extraordinary transactions.

The Company leases non-producing acreage for its exploration and development activities. The cost of these leases plus accumulated delay rentals is recorded at the lower of cost or fair market value. It is expected that evaluation of these leases will occur primarily over the next three years. At December 31, 2003, the costs of these unevaluated, undeveloped oil and gas properties, which are not being amortized, were acquired during the following years:

2003	$ 51,763
2002	47,758
2001	96,669
2000	34,780
1999 and prior	49,595
Total	$ 280,565

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the purchase method of accounting for business combinations and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The oil and gas industry is currently discussing the appropriate balance sheet classification of oil and gas mineral rights held by lease or contract. The Company classifies these assets as a component of oil and gas properties in accordance with its interpretation of SFAS No. 19 and common industry practice. There is also a view that these mineral rights are intangible assets as defined in SFAS 141, "Business Combinations", and, therefore, should be classified on the balance sheet as intangible assets apart from oil and gas properties.

Upon adoption of SFAS 141, the Company did not change its classification of contractual mineral rights. The Company believes its current accounting for such mineral rights as part of oil and gas properties is appropriate under the full cost method of accounting. However, if the accounting for mineral rights held by lease or contract is ultimately changed so that costs associated with mineral rights not held under fee title are required to be classified as long term intangible assets pursuant to the guidelines of SFAS 141, then the reclassified amount as of December 31, 2003, would be $280,565. Management does not believe that the ultimate outcome of this issue will have a significant impact on the Company's cash flows, results of operations or financial condition.

Other Property and Equipment
Other property, plant and equipment is stated at cost. Major replacements and improvements are capitalized. Maintenance and repair costs are generally charged to expense as incurred. When assets are sold, retired, or otherwise disposed of, the cost and related accumulated depreciation are eliminated from the accounts and gain or loss is recognized.

Depreciation of the drilling rig and equipment, after a 20% provision for salvage value, is computed on a composite basis for the total rig investment using the units-of-production method over an estimated useful life of 1,500 drilling days as of the in-service date or date of major refurbishment. Depreciation of the leonardite plant and equipment is computed using the straight-line method over estimated useful lives of 3 to 25 years. Depreciation of other property and equipment is computed principally on the straight-line method over the following estimated useful lives:

Office building	20 years
Office furniture and equipment	3-7 years
Reymert property	15 years

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Impairment of Long-Lived Assets

Potential impairment of long-lived assets (other than oil and gas properties) is reviewed whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. No impairment losses have been recognized on long-lived assets.

Asset Retirement Obligations

If a reasonable estimate of the fair value can be made, the Company will record a liability for legal obligations associated with the future retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal operation of the assets.

The fair value of a liability for an asset retirement obligation is recognized in the period in which the liability is incurred. The fair value is measured using expected future cash outflows (estimated using current prices that are escalated by an assumed inflation rate) discounted at the Company's credit-adjusted risk-free interest rate. The liability is then accreted each period until it is settled or the asset is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded. The initial fair value of the asset retirement obligation is capitalized and subsequently depreciated or amortized as part of the carrying amount of the related asset.

The Company has recorded asset retirement obligations related to its oil and gas properties. The Company has also identified other asset retirement obligations that are not recorded because a reasonable estimate of the fair value cannot be made due to the indeterminate life of the associated assets. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Revenue Recognition

Revenue from the sale of oil and gas production, net of royalties, is recognized when deliveries occur. Revenue from the sale of leonardite products is recognized when shipments are made. Drilling revenue from daywork contracts is recognized as the work progresses. WSDC has not engaged in any footage or turnkey drilling contracts.

Operating Costs and Expenses

Oil and gas production costs, the cost of leonardite sold, and drilling costs exclude a provision for depreciation and depletion. Depreciation and depletion expense is shown in the aggregate in the accompanying consolidated statements of operations.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the amount of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. A valuation allowance is provided for deferred tax assets not expected to be realized.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Stock Options

The Company accounts for stock options under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. The effect on net income or earnings per share if the Company had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation", to stock-based employee compensation has not been presented as no options were granted and therefore there is no effect for the years ended December 31, 2003, 2002, and 2001.

Earnings Per Share of Common Stock

Basic earnings per share is determined using net income divided by the weighted average shares outstanding during the period. Diluted earnings per share is computed by dividing net income by the weighted average shares outstanding, assuming all dilutive potential common shares were issued. The effect of outstanding stock options was antidilutive in 2003, 2002, and 2001.

Recently Issued Accounting Pronouncements

In March 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities". SFAS 149 did not materially effect the financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity". SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. SFAS 150 did not materially effect the financial statements.

B. INDUSTRY SEGMENTS:

The Company assesses performance and allocates resources based upon its products and the nature of its production processes, which consist principally of a) oil and gas exploration, development and production, b) the mining and processing of leonardite, and c) oil and gas drilling. All operations are conducted within the United States. Operations of the drilling segment commenced in January 2002. Accordingly, there are no amounts in the prior periods for this segment. Sales and other material transactions between the segments have been eliminated. Certain corporate costs, assets and capital expenditures that are considered to benefit the entire organization are not allocated to the Company's operating segments. Interest income, interest expense and income taxes are also not allocated to operating segments. There are no significant accounting differences between internal segment reporting and consolidated external reporting. Presented below is information concerning the Company's operating segments for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Revenue:			
Oil and gas	$ 3,614,592	$ 2,980,228	$ 3,064,135
Leonardite	822,219	726,920	1,152,267
Drilling	406,141	280,538	--
	$ 4,842,952	$ 3,987,686	$ 4,216,402
Operating income (loss):			
Oil and gas	$ 1,262,129	$ 826,088	$ 589,582
Leonardite	(150,146)	(122,669)	(44,276)
Drilling	(22,861)	6,054	--
General corporate	(549,839)	(547,342)	(464,317)
	$ 539,283	$ 162,131	$ 80,989
Depreciation and depletion:			
Oil and gas	$ 566,084	$ 535,091	$ 618,394
Leonardite	99,478	103,780	104,562
Drilling	59,133	36,755	--
General corporate	35,212	21,231	21,786
	$ 759,907	$ 696,857	$ 744,742
Identifiable assets, net:			
Oil and gas	$ 8,576,643	$ 6,176,486	$ 5,539,560
Leonardite	848,705	860,868	976,107
Drilling	1,362,538	1,150,093	968,064
General corporate	796,387	860,753	717,988
	$ 11,584,273	$ 9,048,200	$ 8,201,719
Capital expenditures incurred:			
Oil and gas	$ 1,379,720	$ 1,054,608	$ 1,066,050
Leonardite	16,668	17,596	2,500
Drilling	99,388	109,487	968,064
General corporate	2,166	689	23,317
	$ 1,497,942	$ 1,182,380	$ 2,059,931

C. TRADE RECEIVABLES AND MAJOR CUSTOMERS:

Trade receivables at December 31, 2003 and 2002 are comprised of the following:

	2003	2002
Oil and gas purchasers	$ 504,813	$ 443,824
Oil and gas joint interest owners	69,555	96,997
Leonardite customers	246,726	189,115
Drilling customers	275,000	102,939
	1,096,094	832,875
Less allowance for doubtful accounts	(11,416)	(11,416)
	$ 1,084,678	$ 821,459

The Company is subject to credit risk associated with the purchasers of its produced oil and gas products, leonardite products and drilling services. Exposure to this credit risk is controlled through credit approvals and monitoring procedures. Collateral is not required. Receivables from joint interest owners are subject to collection under operating agreements that generally provide lien rights.

The Company primarily sells crude oil. The Company's production of crude oil is concentrated in the Williston Basin of North Dakota, which is a mature basin. In addition, 33% and 11% of the Company's 2003 oil and gas production was from the Wayne Field and Leonard Field, respectively. Due to the significance of these fields, disruptions could adversely affect the Company.

The Company had major customers that purchased oil and gas products as follows:

	Customer	
	A	B
Percent of total revenue for the years ended-		
December 31, 2003	28%	36%
December 31, 2002	38%	29%
December 31, 2001	52%	*
Percent of total accounts receivable as of-		
December 31, 2003	20%	26%
December 31, 2002	24%	30%

* Not a major customer.

Management believes that other purchasers would buy the Company's oil and gas if any of its customers were lost.

D. INVENTORIES:

As of December 31, 2003 and 2002, inventories by major classes are comprised of the following:

	2003	2002
Crude oil	$ 60,416	$ 53,056
Leonardite inventories:		
Finished products	72,220	79,122
Raw materials	34,160	38,860
Materials and supplies	66,510	36,960
Total leonardite inventories	172,890	154,942
	$ 233,306	$ 207,998

E. LONG-TERM DEBT:

Long-term debt at December 31, 2003 and 2002 consists of the following. The oil and gas loan and the revolving line of credit (RLOC) are with the same bank.

	2003	2002
The 1997 Oil & Gas Loan, prime plus .75%, collateralized by oil and gas properties	$ --	$ 260,228
The 2001 Oil & Gas RLOC, converted to a loan January 5, 2004, interest at prime (4.0% rate at December 31, 2003), due in monthly installments of $43,229 plus interest through January 2008, collateralized by oil and gas properties	2,075,000	1,775,000
Installment note payable, 9.5%, due in monthly installments of $320 including interest through January 2005, collateralized by a vehicle	3,936	7,260
Total long-term debt	2,078,936	2,042,488
Less current maturities	(479,457)	(132,260)
Long-term debt, less currentmaturities	$ 1,599,479	$ 1,910,228

Subsequent to year-end, verbal agreement was reached between the Company and its bank, whereby the bank will establish a new $3,000,000 RLOC with interest only payable monthly at the bank's prime rate. The RLOC will expire March 5, 2007, and require repayment of the then outstanding balance by March 5, 2011, in monthly payments at the bank's prime rate. The RLOC will be collateralized by oil and gas properties and all other terms of this new RLOC will be essentially identical to the Company's prior RLOC that expired January 2004. It is fully expected that the new RLOC will be executed in the near future.

E. LONG-TERM DEBT (Continued):

Aggregate maturities required on long-term debt at December 31, 2003, are as follows:

Year Ending December 31:	
2004	$ 479,457
2005	518,750
2006	518,750
2007	518,750
2008	43,229
	$ 2,078,936

The Company's borrowing base for debt secured by oil and gas properties is limited by the net present value of future oil and gas production of the properties as determined annually by the bank.

The Company's oil and gas RLOC/loan was obtained pursuant to financing agreements which include the following covenants: Maintain a current ratio of not less than 1.25 to 1 exclusive of current maturities of long-term debt; maintain debt to tangible net worth of not more than 1.5 to 1; not encumber certain of its assets; restrict borrowings from, and credit extensions to, other parties; restrict reorganization or mergers in which the Company is not the surviving corporation; and not pay cash dividends without the bank's consent. The Company was not in compliance with the current ratio requirement at December 31, 2003.

F. ASSET RETIREMENT OBLIGATIONS:

Effective January 1, 2003, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" which requires that the fair value of a liability for an asset retirement obligation associated with a tangible long-lived asset be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. The asset retirement obligations recorded by the Company relate to the future plugging and abandonment costs of its oil and gas wells.

A liability is incurred in the period in which an oil or gas well is acquired or drilled. The fair value of the liability is estimated based on historical experience in plugging and abandoning wells, federal and state regulatory requirements, estimated useful lives of wells based on engineering studies, estimates of the cost to plug and abandon wells in the future, and the Company's credit-adjusted risk-free interest rate. Revisions of the liability occur due to changes of those factors. Each period the liability is accreted to its future estimated value until the liability is settled. Settlement of the liability occurs when a well is sold or plugged and abandoned. Accretion expense is included in oil and gas production expense on the Company's consolidated statements of operations.

F. ASSET RETIREMENT OBLIGATIONS (Continued):

Prior to adoption of SFAS No. 143, the Company assumed that the salvage value of oil and gas well equipment equaled the plugging and abandonment costs. Therefore, no liabilities for retirement obligations were recorded. The initial adoption of SFAS No. 143 on January 1, 2003, resulted in a one-time non-cash after-tax charge to operations of $23,000 recorded as the cumulative effect of a change in accounting principle. The adoption also resulted in an increase to oil and gas properties being amortized of $1,562,000, a discounted liability for asset retirement obligations of $1,589,000, and a decrease of deferred income tax liabilities of $4,000. There was no impact on the Company's cash flows as a result of adopting SFAS No. 143.

Changes in asset retirement obligations for the year ended December 31, 2003 were as follows:

Beginning of year	$ --
Carrying amount at adoption	1,589,000
Liabilities incurred	25,000
Revisions to estimate	45,000
Accretion expense	76,200
Liabilities settled	--
End of year	$ 1,735,200

Pro forma net income for the years ended December 31, 2003, 2002, and 2001, assuming retroactive application of SFAS No. 143 is as follows:

	2003	2002	2001
Net income	$ 469,563	$ 46,899	$ 14,718
Net income per share, basic and diluted	$ .13	$ .01	$ --

G. INCOME TAXES:

The tax effects of significant temporary differences and carryforwards which give rise to the Company's deferred tax assets and liabilities at December 31, 2003 and 2002, are as follows:

	2003	2002
Deferred Tax Assets:		
Net operating loss carryforward	$ 361,000	$ 179,000
Statutory depletion carryforward	1,678,000	1,621,000
Other	64,000	66,000
	2,103,000	1,866,000
Valuation Allowance:		
Beginning of year	(918,000)	(821,000)
(Increase) decrease	(11,000)	(97,000)
End of year	(929,000)	(918,000)
Deferred Tax Liabilities:		
Property, plant and equipment	(1,580,000)	(1,343,000)
Net Deferred Tax Liability, long-term	$ (406,000)	$ (395,000)

The components of income tax expense for the years ended December 31, 2003, 2002 and 2001, are as follows:

	2003	2002	2001
Current tax benefit	$ 2,452	$ 45,288	$ 23,000
Deferred tax benefit (expense)	(4,000)	46,000	85,000
Increase in deferred tax assets valuation allowance	(11,000)	(97,000)	(145,000)
Income tax (expense)	$ (12,548)	$ (5,712)	$ (37,000)

During 2002 and 2001, the Company recorded deferred tax benefits that resulted primarily from net operating losses generated for which there are no currently refundable federal taxes. During 2003, the Company recorded deferred tax expense of only $4,000 since the benefit of the net operating loss and depletion carryforwards generated was offset by property, plant and equipment timing differences. The Company increased the deferred tax asset valuation allowance in each year based upon the projection of utilizing less statutory depletion carryforwards in the future.

G. INCOME TAXES (Continued):

A receivable for state income taxes of $50,192 was recorded at December 31, 2002, for the carryback of 2002 and 2001 state net operating losses.

The provision for income taxes does not bear a normal relationship to pre-tax earnings. A reconciliation of the U.S. federal income tax rate with the actual effective rate for the years ended December 31, 2003, 2002 and 2001 is as follows:

	2003	2002	2001
Income tax expense at statutory rate	35%	35%	35%
Change in deferred tax assets and liabilities	(32)	(128)	(167)
Change in valuation allowance	2	100	184
Other	(2)	(1)	(5)
	3%	6%	47%

For income tax purposes, the Company has a statutory depletion carryover of approximately $5,890,000 that, subject to certain limitations, may be utilized to reduce future taxable income. This carryforward does not expire. The Company also has a federal net operating loss carryforward of approximately $1,310,000, which if not utilized, will begin to expire in 2021.

H. STOCK OPTION AND PROFIT-SHARING PLANS:

Stock Option Plan

In 1993, the Company adopted the 1993 Incentive Stock Option Plan, whereby 300,000 shares of the Company's common stock were reserved for options that could be granted pursuant to the terms of the plan. Under the terms of the plan, the option price could not be less than 100% of the fair market value of the Company's common stock on the date of grant, and if the optionee owned more than 10% of the voting stock, the option price per share could not be less than 110% of the fair market value. The plan expired February 17, 2003.

Information with respect to the stock option plan's activity is as follows:

	Shares Available for Options	Shares Subject to Outstanding Options
December 31, 2000	98,000	178,000
Granted	--	--
Exercised	--	--
December 31, 2001	98,000	178,000
Granted	--	--
Cancelled	2,500	(2,500)
Exercised	--	--
December 31, 2002	100,500	175,500
Granted	--	--
Cancelled	(100,500)	--
Exercised	--	--
December 31, 2003	--	175,500

Information with respect to the options outstanding and exercisable at December 31, 2003, is as follows:

Number of shares	Exercise Price	Expiration Date
87,500	2.37	May 2007
88,000	2.31	December 2007
175,500		

The average exercise price is $2.34 for options outstanding and exercisable at December 31, 2003.

H. STOCK OPTION AND PROFIT-SHARING PLANS (Continued):

Profit-sharing Plan

The Company has a 401(k) profit sharing plan that covers all employees with one year of service who elect to enter the plan. Effective July 1, 1997, the Company amended the plan to provide for employee contributions. Employees may elect to contribute amounts subject to IRS and plan limitations. The Company contributes an amount equal to each employee's contribution up to a maximum of 5% of the employee's compensation. The Company may also make additional discretionary contributions to the plan. The Company's total contributions to the plan, matching and discretionary, for the years ended December 31, 2003, 2002 and 2001 were $49,593, $26,019 and $24,614, respectively.

I. CONTINGENCIES:

The Company is a defendant in a bankruptcy case with respect to a preference claim brought on November 8, 2002, in the United States Bankruptcy Court, Southern District of Texas, Houston Division (adversary proceeding number 02-03827, In Re: Ramba, Inc., Lowell T. Cage, Trustee v. GeoResources, Inc.) The bankruptcy trustee of a former leonardite customer, Ambar, Inc. (n/k/a Ramba, Inc.) has sued the Company for approximately $139,000 in an amended preference claim in Bankruptcy Court. The defense has been vigorous, and the District Court is presently considering the Company's Motion for Summary Judgment. If the Motion is granted, little exposure to the claim will remain. As of December 31, 2003 and 2002, the Company has recorded a reserve of $50,000 with respect to this matter.

All of the Company's operations are generally subject to federal, state or local environmental regulations. The Company's oil and gas business segment is affected particularly by those environmental regulations concerned with the disposal of produced oilfield brines and other wastes. The Company's leonardite mining and processing segment is subject to numerous state and federal environmental regulations, particularly those concerned with air quality at the Company's processing plant, and surface mining permit and reclamation regulations. The amount of future environmental compliance costs cannot be determined at this time.

J. OFFICE FACILITIES:

In 1991, the Company purchased an office building, one-half of which it occupies. The building is included in other property and equipment in the accompanying consolidated balance sheets and consists of the following at December 31, 2003 and 2002:

	2003	2002
Building and improvements	$ 163,834	$ 163,834
Accumulated depreciation	(104,710)	(96,519)
	$ 59,124	$ 67,315

J. OFFICE FACILITIES (Continued):

The Company leases the remainder of the building to unaffiliated businesses under cancelable lease agreements. During 2003, 2002 and 2001, the Company received $19,800, $19,050, and $20,675, respectively, in rental income from the building that is included in other income in the accompanying statements of operations.

K FINANCIAL INSTRUMENTS:

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. The carrying value of long-term debt approximates fair value based on the variable nature of the interest rates.

L. RELATED PARTY TRANSACTIONS:

At December 31, 2003 and 2002, the Company had made expense advances to its President of $8,627 and $2,100, respectively.

During 2003 and 2002, WSDC incurred rent expense of $3,500 and $9,500, respectively, paid to its President and Vice-President under month-to-month leases for office and shop space. Also during 2002, WSDC paid drilling rig repair expense of $1,650 to a company owned by the Vice President and purchased a vehicle for $11,686 from a company owned by the President. At December 31, 2003 and 2002, WSDC owed $2,461 and $2,611, respectively, to its officers.

M. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES:

Net capitalized costs related to the Company's oil and gas producing activities are summarized as follows as of December 31, 2003, 2002 and 2001:

	2003	2002	2001
Proved properties	$ 24,711,298	$ 22,636,316	$ 21,594,355
Unproved properties	280,565	251,714	239,067
Total	24,991,863	22,888,030	21,833,422
Less accumulated depreciation, depletion, amortization and impairment	(17,043,589)	(17,306,505)	(16,771,414)
Net capitalized costs	$ 7,948,274	$ 5,581,525	$ 5,062,008

M. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Costs incurred in oil and gas property acquisition, exploration and development activities, including capital expenditures are summarized as follows for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Property acquisition costs:			
Proved	$ 25,674	$ 27,799	$ 31,138
Unproved	32,358	38,858	135,148
Exploration costs	231,355	103,545	82,976
Development costs	1,090,333	884,406	816,788
	$ 1,379,720	$ 1,054,608	$ 1,066,050

The Company's results of operations from oil and gas producing activities (excluding corporate overhead and financing costs) are presented below for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Oil and gas sales	$ 3,614,592	$ 2,980,228	$ 3,064,135
Production costs	(1,786,379)	(1,619,049)	(1,856,159)
Depletion, depreciation and amortization	(566,084)	(535,091)	(618,394)
	1,262,129	826,088	589,582
Imputed income tax provision	--	--	--
	$ 1,262,129	$ 826,088	$ 589,582

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

The reserve information presented below is based upon reports prepared by the independent petroleum engineering firm of Broschat Engineering and Management Services. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of mature producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions existing as of the end of each respective year. The year-end selling price of oil and gas is one of the primary factors affecting the determination of proved reserve quantities which fluctuate directly with that price. The selling price of oil was significantly lower at December 31, 2001, than at December 31, 2003 or 2002.

M. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited) (Continued)
Presented below is a summary of the changes in estimated proved reserves of the Company, all of which are located in the United States, for the years ended December 31, 2003, 2002 and 2001:

	2003		2002		2001	
	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)
Proved reserves, beginning of year	2,487,000	421,000	2,098,000	350,000	2,487,000	545,000
Purchases of reserves-in-place	--	--	21,000	--	--	---
Sales of reserves-in-place	--	--	--	--	(1,000)	(72,000)
Extensions and discoveries	34,000	--	--	--	--	--
Improved recovery	--	--	136,000	--	--	--
Revisions of previous estimates	73,000	(26,000)	372,000	82,000	(238,000)	(112,000)
Production	(136,000)	(8,000)	(140,000)	(11,000)	(150,000)	(11,000)
Proved reserves, end of year	2,458,000	387,000	2,487,000	421,000	2,098,000	350,000

Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves of the Company are presented below as of December 31:

	Oil (bbl)	Gas (mcf)
2003	1,636,000	387,000
2002	1,582,000	421,000
2001	1,330,000	350,000

M. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited)

Statement of Financial Accounting Standards No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines which are briefly discussed below. Future cash inflows and future production and development costs are determined by applying year-end selling prices and year-end production and development costs to the estimated quantities of oil and gas to be produced. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. Estimated future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion, depletion carryforwards, net operating loss carryforwards, and investment tax credit carryforwards. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's expectations of actual revenues or future net cash flows to be derived from those reserves nor their present worth.

Presented below is the standardized measure of discounted future net cash flows as of December 31, 2003, 2002 and 2001. As shown, the future cash inflows as of December 31, 2001, were significantly lower than at December 31, 2003 or 2002. This is primarily due to the low oil price in effect on December 31, 2001.

	2003	2002	2001
Future cash inflows	$ 70,919,000	$ 65,178,000	$ 29,635,000
Future production costs	(28,371,000)	(25,792,000)	(13,963,000)
Future development, retirement and salvage	(5,267,000)	(4,408,000)	(3,958,000)
Future income tax expense	(9,748,000)	(9,457,000)	(2,114,000)
Future net cash flows	27,533,000	25,521,000	9,600,000
Less effect of a 10% discount factor	(11,966,000)	(11,063,000)	(4,120,000)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 15,567,000	$ 14,458,000	$ 5,480,000

M. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited) (Continued)

The principal sources of change in the standardized measure of discounted future net cash flows are as follows for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Standardized measure, beginning of year	$ 14,458,000	$ 5,480,000	$ 15,022,000
Sales of oil and gas produced, net of production costs	(1,828,000)	(1,361,000)	(1,208,000)
Net changes in prices and production costs	1,690,000	9,621,000	(12,192,000)
Purchases of reserves-in-place	--	180,000	--
Sales of reserves-in-place	--	--	(54,000)
Extensions, discoveries and other additions, less related costs	325,000	1,190,000	--
Revisions of previous quantity estimates and other	594,000	3,337,000	(1,240,000)
Development costs incurred during the year and changes in estimated future development costs	4,000	(235,000)	45,000
Revisions of asset retirement obligations, net of salvage value	(364,000)	--	--
Accretion of discount	853,000	406,000	480,000
Net change in income taxes	(165,000)	(4,160,000)	4,627,000
Standardized measure, end of year	$ 15,567,000	$ 14,458,000	$ 5,480,000

Signatures

Pursuant to the requirements of Section 13 of the Exchange Act, the Registrant caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GEORESOURCES, INC. (the "Registrant")

Dated: March 30, 2004

/s/ J. P. Vickers
J. P. Vickers, President

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

(Power of Attorney)

Each person whose signature appears below constitutes and appoints J. P. VICKERS and DENNIS HOFFELT his true and lawful attorneys-in-fact and agents, each acting alone, with full power of stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-KSB and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, each acting alone, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in each acting alone, or his substitute or substitutes, may lawfully do or cause to be done by virtue thereof.

Signatures	Title	Date
/s/ J. P. Vickers J. P. Vickers	President (principal executive officer and principal financial officer) and Director	3/30/04
/s/ Cathy Kruse Cathy Kruse	Secretary and Director	3/30/04
/s/ Dennis Hoffelt Dennis Hoffelt	Director	3/30/04
/s/ Paul A. Krile Paul A. Krile	Director	3/30/04
/s/ Nick Voller Nick Voller	Director	3/30/04
/s/ Duane Ashley Duane Ashley	Director	3/30/04

OFFICERS & DIRECTORS

J.P. Vickers
Director & President
Williston, North Dakota

Jeffrey B. Jennings
VP, Land & Finance
Williston, North Dakota

Cathy Kruse
Director & Secretary
Williston, North Dakota

Connie R. Hval
Treasurer
Williston, North Dakota

H. Dennis Hoffelt
Director, Audit Committee
Williston, North Dakota

Paul A. Krile
Director, Audit Committee
President & Owner
Ranco Fertiservice
Sioux Rapids, Iowa

Nick Voller
Director, Audit Committee
Certified Public Accountant
Williston, North Dakota

Duane Ashley
Director
Senior Salesman
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TRANSFER AGENT

For information regarding change of address or other information regarding your stockholder account, please contact our transfer agent directly:
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
1-800-468-9716
www.wellsfargo.com/com/shareowner_services

STOCK TRADED

Our Common Stock trades on the Nasdaq SmallCap Market tier of the Nasdaq Stock Market under the symbol GEOI.

SECURITY MARKET MAKERS

The following investment securities firms made a market in our Common Stock during 2003:

Archipelago, L.L.C., Chicago, IL
Cincinnati Stock Exchange, Cincinnati, OH
Goldman Sachs & Co., New York, NY
Knight Securities L.P., New York, NY
Morgan, Keegan, Inc., Birmingham, AL
National Stock Exchange, Cincinnati, OH
Schwab Capital Markets, Jersey City, NJ
The Brut ECN, LLC, Ridgefield, NJ

FORWARD LOOKING INFORMATION

Information herein contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by words such as "may," "expect," "anticipate," "estimate," or "continue," or comparable words. In addition, all statements other than statements of historical facts that address activities that the Company expects or anticipates will or may occur in the future are forward-looking statements. Readers are encouraged to read the SEC reports of the Company, particularly its Form 10-KSB for the Fiscal Year Ended December 31, 2003, for meaningful cautionary language disclosure.

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