GEORESOURCES, INC.

P.O. Box 1505 ✦ 1407 W. Dakota Parkway, Ste. 1-B ✦ Williston, ND 58802-1505
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DATE: June 24, 2005

TO: Tracie Towner
United State Securities and Exchange Commission
Division of Corporation Finance
(Tel) 202-551-3744
(Fax) 202-772-9368

FROM: Cathy Kruse, Director and Corporate Secretary
Connie Hval, Treasurer and Chief Financial Officer
GeoResources, Inc.
(Tel) 701-572-2020
(Fax) 701-572-0277

RE: Number of pages including cover sheet: 19

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June 23, 2005

Tracie Towner
United States Securities and Exchange Commission
Division of Corporate Finance
Mail Stop 04-05
Washington, DC 20549-0405

Re: GeoResources, Inc.
Form 10-KSB for Fiscal Year Ended December 31, 2004
Filed March 30, 2005
Form 10-QSB for Fiscal Quarter Ended March 31, 2005
Filed May 13, 2005
File No. 0-08041

Dear Ms. Towner,

We are in receipt of your correspondence dated June 6, 2005, addressing issues after reviewing the above-referenced SEC filings. Attached are proposed amendments to our filings for Items 1-5, 9 and 11. Items 6, 7, 8 and 10 are addressed in this letter.

1. Critical Accounting Policies. We have amended this section of our Form 10-KSB to include additional information about significant estimates used in the preparation of our financial statements.

2. Results of Operation. We have amended the comparison of 2004 to 2003 revenue, costs and gross margin to exclude gross margin and include operating income. Operating income is fully burdened with depreciation, depletion and amortization relating to our production and is an applicable reconciliation consistent with SAB Topic 11:B.

3. Controls and Procedures. In Item 8A. of our SEC Form 10-KSB and Item 3 of our SEC Form 10-QSB, we have amended our controls and procedures to include a specific officer, the Chief Executive Officer and Chief Financial Officer, Mr. J. P. Vickers, to ensure that material information relating to the Company is made known to him. All material documents are evaluated and reviewed by Mr. Vickers.

4. Controls and Procedures. In Item 308(c) of Regulation S-B, any change in the small business issuer's "internal control over financial reporting" identified must be evaluated to determine if it is reasonably likely to materially affect the small business. We have amended our above-referenced filings to replace "significant" with "any."

RESPONSE TO COMMENT NO. 5

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Oil and Gas Properties
The Company utilizes the full cost method of accounting for oil and gas properties. All costs relating to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred. ~~Accordingly, a~~ All costs associated with the acquisition, exploration and development of oil and gas reserves are capitalized. ~~(~~ Such costs include ~~ing~~ 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 $4.68, $4.12, and $3.76 for 2004, 2003, and 2002, 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 2004, 2003 or 2002.

Gains or losses are not recognized upon the sale or other disposition of oil and gas properties, except in extraordinary transactions. Consideration received from the sale or other disposition of oil and gas properties, including from sales or transfers of properties in connection with partnerships, joint venture operations, or other forms of drilling arrangements (e.g., carried interest, turnkey wells, management fees, etc.), is credited to capitalized costs except to the extent that such consideration represents the reimbursement of current expenses.

No income is recognized from the performance of contractual services (e.g. drilling, well service, etc.) related to properties in which the Company holds an ownership or other economic interest. Any such income not recognized is credited to capitalized costs.

Ms. Tracie Towner
Division of Corporation Finance
June 23, 2005
Page Two

5. Oil and Gas Properties section of the Significant Accounting Policies footnote.
   - The disclosure required by Rule 4-10(c)(5) of Regulation S-X is added to the first paragraph.
   - We believe the accounting for the transactions described in Rule 4-10(c)(6)(I) of Regulation S-X is disclosed in the fourth paragraph which states "Gains or losses are not recognized upon the sale or other disposition of oil and gas properties, except in extraordinary transactions."
   - We believe the accounting for the transactions described in the first part Rule 4-10(c)(6)(ii) of Regulation S-X regarding the ordinary purchase of reserves is disclosed in the first paragraph which states that all acquisition costs are capitalized.
   - For the years presented, the Company did not enter into any transaction to which the second part of Rule 4-10(c)(6)(ii) (regarding the purchase of reserves with substantially shorter lives than the production center) would be applicable.
   - The accounting for the transactions described in Rule 4-10(c)(6)(iii)(A) of Regulation S-X is added to the fourth paragraph.
   - The transactions described in Rule 4-10(c)(6)(iii)(B) of Regulation S-X are not applicable to GeoResources, Inc.
   - The accounting for the transactions described in Rule 4-10(c)(6)(iv)(A), (B), and (D) of Regulation S-X is added as a new fifth paragraph. The transactions described in Rule 4-10(c)(6)(iv)(C) are not applicable to GeoResources.

6. Income Taxes related to Oil & Gas Producing Activities, Note N. Usage of the term "imputed" is intended to make it clear to the reader that the indicated tax provision is not an amount that is actually payable or expected to be paid to taxing authorities. In accordance with paragraph 26 of SFAS 69, the statutory tax rate of 35% was used to compute the amount of the provision. Following is a schedule showing the computation of the provision for the 3 years presented.

	2004	2003	2002
O&G sales	4,452,114	3,614,592	2,980,228
Production costs	(1,922,479)	(1,786,379)	(1,619,049)
DD&A	(580,106)	(566,084)	(535,091)
O&G book operating income	1,949,529	1,262,129	826,088
Current year O&G tax deductions	(678,353)	(735,519)	(665,969)
O&G Net Operating Loss	(1,128,867)	(703,602)	(320,231)
Taxable income (loss)	142,309	(176,992)	(160,112)
Tax @ 35%	49,808	-	-

7. Standardized Measure. Due to the adoption of SFAS 143 effective January 1, 2003, we believe it is appropriate that the total discounted future net cash flows of proved oil and gas reserves should include the future asset retirement obligations associated with our wells and the related future salvage value of the equipment. Because those amounts are relatively small, we considered it reasonable to combine them with the future development costs that are disclosed in accordance with SFAS 69. We believe that inclusion of the asset retirement obligation and related salvage value provides a more comprehensive reflection of future cash flows and is more consistent with the basis of presentation of the financial statements.

Development costs" rather than "Future development, retirement and salvage." Also, the line item for "Revisions of asset retirement obligations, net of salvage value" would be deleted from the schedule of changes in the standardized measure.

8. Leonardite Plant and Mine. We have reviewed the recommended Industry Guide 7 (b)(5). In future filings, we agree to disclose the estimated tonnage and grades or quality, where appropriate. At current production rates, our recoverable tons equal 560,000 ton.

9. Comparison of 2004 to 2003 Revenue, Costs and Gross Margin for Oil and Gas Operations. In addition to the changes in Item 2 above, we have further amended the comparison of 2004 to 2003 revenue, costs and gross margin to include information regarding secondary recovery reserves attributable to LWMU.

10. Estimated Quantities of Proved Oil and Gas Reserves. The increase in proved oil reserves during the last 3 years is mainly attributable to increasing oil prices. The majority of wells evaluated have extremely low rates of production decline, typically less than 6%. Consequently, recoverable reserves are very price sensitive and an increase in crude prices will extend the life of these wells and significantly increase recoverable reserves.

11. Controls and Procedures for Form 10-QSB for the Fiscal Quarter Ended March 31, 2005. After reviewing Section II.F.4 of Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, SEC Release No. 33-8238, our principal financial officer concludes that our controls and procedures are effective. See the amended terminology resulting from Items 3 and 4 of this letter.

In connection with responding to your comments, please be advised that we acknowledge the following:

- GeoResources, Inc. is responsible for the adequacy and accuracy of the disclosure in this filing;
- That staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to this filing; and
- We may not assert staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

The proposed amendments to our filings are enclosed herewith. If you have any questions, please do not hesitate to call one of us at the number above. Thank you for your time and consideration to this matter.

Sincerely,

GEORESOURCES, INC.

Cathy Kruse

Cathy Kruse
Director/Corporate Secretary

Connie Hval

Connie Hval
Chief Financial Officer

Enclosures

RESPONSE TO COMMENT NO. 1

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

General. The preparation of financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, management evaluates its estimates, including evaluations of any allowance for doubtful accounts and impairment of long-lived assets. Management bases its estimates on historical experience and various other assumptions it believes to be reasonable under the circumstances. The results of these evaluations form a basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, management believes that its estimates are reasonable and as accurate as possible given currently available information. The following critical accounting policies relate to the more significant judgments and estimates used in the preparation of our consolidated financial statements. ~~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 plus ~~and estimated~~ estimated future development and dismantlement costs is depleted on the unit-of-production based ~~is~~ on our total ~~using~~ proved oil and gas reserves as estimated by independent petroleum engineers. ~~determined by independent petroleum engineers.~~

Proved ~~R~~reserves are the quantity of oil and gas that may be recovered in the future from known reservoirs under economic and operating conditions existing as of the end of the year. Reserve estimates change over time as additional information becomes available and assumptions regarding future events are revised. Reserve engineering is a subjective process that is dependent on the quality of available data ~~and~~ on engineering and geological interpretation and judgment,~~.~~ and on assumptions of oil and gas commodity prices, production costs and ~~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 and dismantlement costs. ~~increases, our depletion increases, which reduces our net income.~~

The independent petroleum engineers who estimate our proved reserves rely primarily on the historical volumetric production from our properties or similar properties in the area. Also, it is assumed that future oil and gas prices, production costs, and development and dismantlement costs will be the same as those actually prevailing at the end of the year and that those prices and costs will remain constant for all future periods. Our future development projects are based on the undeveloped properties that we own as of year-end and on our long-term capital expenditures budget.

All of the underlying estimates and assumption utilized in estimating our proved reserves and future development and dismantlement costs will change over time. However, the factor that has historically had the greatest impact on the estimation of our proved reserves is the actual year-end oil commodity price that is assumed to remain constant for all future years. Oil prices are volatile and influenced by numerous factors beyond our control. See also "Risk Factors" in Item 1 to this report for further information regarding oil prices and reserves.

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. All of the factors discussed in the three paragraphs above also effect the determination of the present value of the future cash inflows from proved reserves. 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

Our ~~Potential impairment of~~ long-lived assets consist of ~~(other than oil and gas properties)~~ property and equipment. Other than oil and gas properties previously discussed, long-lived assets with an indefinite life are reviewed at least annually for impairment, while other long-lived assets are ~~is~~ reviewed whenever events or changes in circumstances indicate that ~~the~~ carrying values ~~amount~~ of these asset~~-assets may~~ are -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. Our estimate of future net cash flows is primarily based upon the assumption that the trends of actual historical cash flows will continue in the future for the projected remaining physical life of the property. 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. The fair value of the liability is estimated based on historical experience in plugging and abandoning wells, federal and state regulatory requirements, estimated productive lives of wells, estimates of the cost to plug and abandon wells in the future, and the Company's credit-adjusted risk-free interest rate. Any or all of those factors may change over time as additional information becomes available. The effect of such changes on our estimate of the liability is recorded in the period in which the change is made. The factor that is most likely to have a material effect on our estimated liability is the estimated productive lives of wells. This estimate is based on the study by our independent petroleum engineers discussed in the oil and gas properties section above.

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 record ~~estimate our~~ income taxes expense. . This process involves calculating ~~estimating~~ our current taxes payable ~~exposure~~ and ~~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 estimate the recoverability of ~~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. Due to our history of incurring taxable losses in most years, we do not project that we will generate future taxable income. Therefore, the recoverability of our deferred tax assets is based solely on the future reversal of existing timing differences. ~~To the extent we believe that recovery is not likely, we must establish a valuation allowance.~~ Accordingly, w~~We~~e have recorded a valuation allowance ~~due to uncertainties related to our ability to utilize some~~ for the excess ~~of~~ of our statutory depletion carryforward over the future reversal of existing timing differences. ~~. 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 ~~Off Balance Sheet Arrangements~~

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

RESPONSE TO COMMENT NO. 2

Comparison of 2004 to 2003 ~~Revenue, Costs and Gross Margin~~ For Oil and Gas Operations

	Year 2004	% Increase (Decrease) From 2003	Year 2003	% Increase (Decrease) From 2002
Oil and gas production sold (BOE)	123,831	(9.8%)	137,237	(3.5%)
Average price per BOE	$ 35.95	36.5%	$ 26.34	25.7%
Oil and gas revenue	$ 4,452,114	23.2%	$ 3,614,592	21.3%
Production costs	$ 1,922,479	7.6%	$ 1,786,379	10.3%
Average production cost per BOE	$ 15.53	19.3%	$ 13.02	14.3%
Depreciation, depletion and amortization	$ 580,106	2.5%	$ 566,084	5.8%
~~Gross margin~~	~~$ 2,529,635~~	~~38.4%~~	~~$ 1,828,213~~	~~34.3%~~
Operating income	$ 1,949,529	54.5%	$ 1,262,129	52.8%

The relative changes in revenue, production costs and gross margin for oil and gas operations in years ended 2004 and 2003 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, and gas in thousands of cubic feet at atmospheric conditions, abbreviated MCF. We convert gas to its approximate "oil equivalent" by its relative energy content of six MCF to 1 BBL of oil to express total oil and gas sales in barrels of oil equivalent, abbreviated BOE.

Total 2004 oil and gas production sold expressed in BOE followed the trend of each of the quarters of 2004 lagging 9% to 10% behind 2003 sales volumes resulting in 9.8% or 13,400 barrels less than 2003. While this was disappointing to us, there were several reasons for the lower volumes. First, and foremost, was our desire to use administrative and technical resources to create the Landa West Madison Unit, (LWMU), a project that consumed much of our human resources from May 2004, through October 1, 2004, when the North Dakota Industrial Commission-Oil and Gas Division finally approved that Unit. Creating that unit required the drilling of 1 well (0.92 net) that was our first 2004 well drilled. Creation of that Unit is now behind us, and almost all of the water-flood implementation facilities were completed through the winter months. We had hoped water injection could have started by year-end 2004, but equipment and labor shortages combined with winter weather conditions delayed the initiation of water injection until the spring of 2005. Our second drilling project for 2004 was a 10% working interest in an 8,000-foot exploratory well that was basically only seismically defined. Since we perceived the LWMU a shallow, low risk project (92% working interest), we desired to combine that with a smaller interest in a deeper and higher risk project that could have the potential to discover a new field. Unfortunately that well did not result in any production for 2004, but technical analysis showed that it should be capable of production, possibly with horizontal technology. Even before drilling the well, the prospect partners were committed to running 3D seismic on the 2,000-acre prospect area. That seismic was completed in 2004, and from that a horizontal leg might be drilled in the existing well during 2005. As a result of most of our efforts being directed to the LWMU and not realizing any new production from our exploratory prospect, production declined at the approximate decline of all our wells for 2004 compared to 2003.

Although the production we sold was about 10% less in 2004 compared to 2003, the average value of our sales was dramatically higher leading to a significant increase in our oil and gas revenue. Revenue per BOE was higher in every quarter of 2004, from $2.13 higher in the first quarter to $13.78 higher in the fourth. Oil and gas prices were the single most important aspect of our operating performance and financial results during 2004. 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 8% in 2004, some of which directly relates to the higher oil and gas revenues, as production taxes are an "ad valorem" tax, a straight percentage of value produced at the wellhead. In 2004, $53,000 of the $136,000 increase in production costs was due to taxes. In addition, our expenses were generally higher in almost all categories due to the higher demand for oilfield goods and services. Also, the higher per Bbl revenue allowed us to increase discretionary spending. Those discretionary costs and taxes would be reduced if oil prices decrease. Discretionary costs reductions 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. The combination of lower production quantity and higher production costs resulted in 2004 average production cost per barrel increasing about 19% over 2003. Production costs and costs per BOE are one of the few financial areas we can control to a certain degree.

The margin between average revenue per BOE and average cost per BOE was $20.42 in 2004 compared to $13.32 in 2003. Oil and gas depletion in 2004 was $580,106, or 2% higher than 2003. ~~As a result, our gross margin~~ Operating income for the oil and gas segment of our operations increased to ~~$2.5~~ $1.9 million in 2004 compared to ~~$1.8~~$1.3 million for 2003. ~~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 2005 to be a year of high activity for us and the oil and gas industry. We have one drilling permit remaining from an un-drilled well we had budgeted for 2004 and a new permit in progress, both of which are in Bottineau County, ND. We believe many oil and gas operating companies intend to increase their exploration and production activities in 2005. That will strain the availability of oil and gas related labor, equipment and services which may adversely affect our ability to reach our goals.

Comparison of 2004 to 2003 ~~Revenue, Costs and Gross Margin~~ For Drilling Operations

	Year 2004	% Increase (Decrease) From 2003	Year 2003	% Increase (Decrease) From 2002
Operating days	133.1	136.8%	56.2	55.2%
Drilling revenue	$ 1,077,367	165.3%	$ 406,141	44.8%
Average revenue per day	$ 8,094	12%	$ 7,227	(6.7%)
Drilling Costs	$ 1,009,051	172.8%	$ 369,869	55.6%
Average costs per day	$ 7,581	15.2%	$ 6,581	–%
Depreciation, depletion and amortization	$ 128,335	117%	$ 59,133	60.9%

~~Gross margin~~	~~$ 68,316~~	~~88.3%~~	~~$ 36,272~~	~~(15.3%)~~
Operating income (loss)	$ (60,019)	(163%)	$ (22,861)	(478%)

Our oil and gas drilling subsidiary, Western Star Drilling Company, ("WSDC") commenced operations January 2, 2002, and its assets basically consist of one drilling rig labeled E-25 capable of drilling depths up to 8,000 feet. 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 were 148 in 2004 compared to 85 in 2003. During 2004, drilling operations consisted of one well for us, and five wells for other operators, for a total of six wells with footage of 40,270. This compares to five drilled in 2003, of which three were drilled for us and two for other operators, with footage of 20,122. The significant increase in 2004 footage was due to deeper depths of the 2004 drilling.

The increased level of rig utilization for 2004 met our expectations, and we believe the demand for drilling services should be higher in 2005. Operating days and revenue from companies other than GeoResources more than doubled in 2004 as demand for drilling services increased. Drilling costs also increased substantially in fairly close proportion to revenue. Part of the drilling cost increases were due to rig repairs and discretionary upgrading as we continue making rig improvements using drilling cash flow. Revenue and costs per day were also both higher. The costs per day were higher due to the factors mentioned above, and the per day revenue increased due to WSDC's ability to charge more for its improved equipment. 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 ways including day-work, turnkey and footage.

Drilling rig depreciation in 2004 was $128,335, or 117% higher due to the increased number of days the rig was utilized. Operating income (loss) in 2004 was ($60,019) compared to a loss of $22,861 in 2003. ~~As a result of revenue and costs, drilling gross margin in 2004 was almost twice as high compared to 2003, although both were somewhat slim margins with 2004 at 6.3% of revenue and 2003 at 8.9%.~~ Because WSDC has value to us over and above its financial profit potential, our primary goal in these first few years is that drilling operations result in a positive ~~gross margin and~~ cash flow. ~~When depreciation is taken into account for WSDC, neither year contributed to our net income, but it was not our expectation that it would.~~ Going forward, we still expect cash flow from drilling operations may be re-invested into the drilling equipment to expand WSDC's project capabilities.

Comparison of 2004 to 2003 Consolidated Analysis of the Financial Statements

	Year 2004	% Increase (Decrease) From 2003	Year 2003	% Increase (Decrease) From 2002
Total operating revenue	$ 6,820,125	41%	$ 4,842,592	21%
Cost of operations	$ 4,099,678	36%	$ 3,006,621	16%
~~Total gross margin~~	~~$ 2,720,447~~	~~48%~~	~~$ 1,836,331~~	~~31%~~
Depreciation, depletion and amortization	$ 842,658	11%	$ 759,907	9%
Selling, general and administrative	$ 594,017	11%	$ 537,141	(2%)
Operating income	$ 1,283,772	138%	$ 539,283	233%
Nonoperating expenses	$ (60,639)	6%	$ (57,172)	(12%)
Income before taxes	$ 1,223,133	154%	$ 482,111	397%
Income taxes	$ 117,287	835%	$ 12,548	120%
Effect of change in accounting principle	--	--	$ (23,000)	--
Net income	$ 1,105,846	148%	$ 446,563	389%

~~Oil and gas depletion in 2004 was $580,106, or 2% higher than 2003. Leonardite depreciation in 2004 was $99,412 and remained relatively flat. Drilling rig depreciation in 2004 was $128,335, or 117% higher due to the increased number of days the rig was utilized.~~ Depreciation on general corporate assets in 2004 was $34,805, or 1% lower than 2003. General corporate depreciation includes our office building and equipment and amortization of the Reymert property.

Selling, general and administrative costs (SG&A) were 11% higher in 2004 due in part to higher selling costs associated with our 54% increase in leonardite sales and a $19,000 non-routine parking lot repair.

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 H to the Financial statements for further information. The $23,000 charge for an accounting change in 2003 is entirely due to our adoption of SFAS 143. See Note G to the Financial Statements for further information.

As a result of all the factors discussed above, net income was $1,105,846 or $0.30 per share compared to a net income of $446,563 or $0.12 per share in 2003.

Comparison of 2004 to 2003 ~~Revenue, Costs and Gross Margin~~ For Leonardite Operations

	Year 2004	% Increase (Decrease) From 2003	Year 2003	% Increase (Decrease) From 2002
Leonardite sold (Tons)	10,093	53.9%	6,558	0.7%
Average price	$ 127.88	2.0%	$ 125.38	12.3%
Leonardite revenue	$ 1,290,644	57.0%	$ 822,219	13.1%
Production costs	$ 1,168,148	37.4%	$ 850,373	17.0%
Average production costs per ton	$ 115.74	(10.7%)	$ 129.67	16.2%
Depreciation, depletion and amortization	$ 99,412	--	$ 99,478	(4.1%)
~~Gross margin (deficit)~~	~~$ 122,496~~	~~535%~~	~~$ (28,154)~~	~~(7,751%)~~
Operating income (loss)	$ 23,084	118%	$ (127,632)	(23.4%)

Leonardite product sales were $1,290,644 in 2004 compared to $822,219 in 2003, an increase of $468,425 or 57%. This increase was due to more drilling activity in the Gulf and more specialty product sales as a result of the higher oil prices. Production sold in 2004 was 10,093 tons at an average price of $127.88 compared to 6,558 tons at an average price of $125.38 for 2003.

Cost of leonardite sold was $1,168,148 in 2004 compared to $850,373 in 2003, an increase of $317,775 or 37.4%. Average production costs per ton were $115.74 and $129.67 for 2004 and 2003, respectively. Costs per ton decreased approximately 10.7% for 2004 compared to 2003 due mainly to the higher sales volume in relation to fixed costs. Leonardite depreciation in 2004 was $99,412 and remained relatively flat.

~~Gross margin for 2004 leonardite operations before deductions for depreciation and selling, general and administrative expenses was $122,496 compared to a deficit of $28,154 for 2003. The increase in 2004 gross margin was higher sales and lower production costs as discussed above.~~

RESPONSE TO COMMENT NO. 3 & 4

ITEM 8A. <u>CONTROLS AND PROCEDURES</u> <u>(Form 10-KSB)</u>

The Company's ~~We carried out an evaluation under the supervision and with the participation of our management, including our~~ Chief Executive Officer and Chief Financial Officer, Mr. J. P. Vickers, has implemented the Company's disclosure controls ~~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"))~~ to ensure that material information relating to the Company is made known to Mr. Vickers. Our executive officers have evaluated the effectiveness of the Company's disclosure controls and procedures as of March 31, 2005 (the "Evaluation Date"). ~~,~~ Based on such ~~that~~ evaluation, Mr. Vickers ~~our Chief Executive Officer and Chief Financial Officer~~ concluded that, as of the Evaluation Date, the Company's ~~our~~ disclosure controls and procedures are effective in alerting him on a timely basis to material ~~to ensure that~~ information relating ~~required~~ to the Company that is required to be included in our reports filed or submitted under the Security ~~be disclosed by us in our~~ Exchange Act of 1934. ~~reports was recorded, processed, summarized and reported within the applicable time periods.~~ Moreover, ~~tT~~here were ~~have been~~ no ~~significant~~ changes ~~to our~~ in internal controls or~~, to our knowledge,~~ in other factors that have materially ~~could significantly~~ affected or are reasonably likely to materially affect the Company's internal ~~these~~ controls over financial reporting.~~, including any corrective actions with regard to significant deficiencies and material weaknesses.~~

RESPONSE TO COMMENT 3, 4 & 11

Item 3. Controls and Procedures.

10QSB

~~As of the end of the period covered by this report, we evaluated, under the supervision and with the participation of our management, including our~~ The Company's -Chief Executive Officer and Chief Financial Officer, Mr. J. P. Vickers, has implemented the Company's ~~the effectiveness of the design and operation of our~~ disclosure controls and procedures to ensure that material information relating to the Company is made known to Mr. Vickers. ~~over financial reporting pursuant to Rule 13a-15 and 15d-15 of the Securities Exchange Act of 1934. Based upon that evaluation, our Chief Executive Officer and Chief Financial~~ Our executive ~~O~~officers have evaluated the effectiveness of the Company's ~~concluded that our~~ disclosure controls and procedures as of March 31, 2005 (the Evaluation Date"). ~~over financial reporting are adequate and effective in timely alerting them to material information required to be included in this quarterly report on Form 10-QSB.~~ Based on such evaluation, Mr. Vickers concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective in alerting him on a timely basis to material information relating to the Company that is required to be included in our reports filed or submitted under the Securities Exchange Act of 1934.

~~Disclosure controls and procedures, no matter how well-designed and implemented, can provide only reasonable assurance of achieving an entity's disclosure objectives. The likelihood of achieving such objectives is affected by limitations inherent in disclosure controls and procedures. These limitations include the fact that human judgment in decision-making can be faulty and that breakdowns in internal control can occur because of human failures such as simple errors or mistakes or because of intentional circumvention of the established process.~~

During the period covered by this report, there have been no ~~significant~~ changes in our internal controls over financial reporting or in other factors, that have ~~which could~~ materially ~~significantly~~ affected or are reasonably likely to materially affect the Company's internal controls over financial reporting. ~~, including any corrective actions with regard to significant deficiencies or material weaknesses.~~

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, 2004, the costs of these unevaluated, undeveloped oil and gas properties, which are not being amortized, were acquired during the following years:

2004	$	40,556
2003		36,388
2002		32,022
2001		59,744
2000 and prior		45,211
Total	$	213,921

RESPONSE TO COMMENT NO. 9 (CHANGES MADE FROM ORIGINAL DOCUMENT NOT FROM CHANGES MADE FOR COMMENT NO. 2)

Comparison of 2004 to 2003 Revenue, Costs and Gross Margin For Oil and Gas Operations

	Year 2004	% Increase (Decrease) From 2003	Year 2003	% Increase (Decrease) From 2002
Oil and gas production sold (BOE)	123,831	(9.8%)	137,237	(3.5%)
Average price per BOE	$ 35.95	36.5%	$ 26.34	25.7%
Oil and gas revenue	$ 4,452,114	23.2%	$ 3,614,592	21.3%
Production costs	$ 1,922,479	7.6%	$ 1,786,379	10.3%
Average production cost per BOE	$ 15.53	19.3%	$ 13.02	14.3%
Gross margin	$ 2,529,635	38.4%	$ 1,828,213	34.3%

The relative changes in revenue, production costs and gross margin for oil and gas operations in years ended 2004 and 2003 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, and gas in thousands of cubic feet at atmospheric conditions, abbreviated MCF. We convert gas to its approximate "oil equivalent" by its relative energy content of six MCF to 1 BBL of oil to express total oil and gas sales in barrels of oil equivalent, abbreviated BOE.

Total 2004 oil and gas production sold expressed in BOE followed the trend of each of the quarters of 2004 lagging 9% to 10% behind 2003 sales volumes resulting in 9.8% or 13,400 barrels less than 2003. While this was disappointing to us, there were several reasons for the lower volumes.

First, and foremost, was our desire to use administrative and technical resources to create the Landa West Madison Unit, (LWMU), a project that consumed much of our human resources from May 2004, through October 1, 2004, when the North Dakota Industrial Commission-Oil and Gas Division finally approved that Unit. Creating that unit required the drilling of 1 well (0.92 net) that was our first 2004 well drilled. Creation of that Unit is now behind us, and almost all of the water-flood implementation facilities were completed through the winter months. We had hoped water injection could have started by year-end 2004, but equipment and labor shortages combined with winter weather conditions delayed the initiation of water injection until the spring of 2005. As a result of the formation of LWMU, secondary recoverable reserves (105,000 BO) were assigned to Proved Developed of which 50% were classified as Proved Developed Non-producing and 50% as Proved Developed Producing.

The Grann-County#1 well was taken off of production in June, 2004 in preparation for conversion to water injection. Prior to any active water injection LWMU production realized a quick positive response by removing 200 Bbls/day of fluid draw down from the reservoir. This helped to augment the line drive mechanism already existing in the adjoining Landa Madison Unit. Secondary reserves (53,000 BO) due to the Grann-County #1 injection well were assigned to Proved Developed Producing.

An additional 52,000 BO of secondary reserves were assigned to Proved Developed Non-Producing in anticipation of the Stella Rice 2-27 being completed as an injection well. Conversion of both wells to water injectors is expected to be completed during the summer, 2005. This will fully complete the line drive mechanism in the water flood.

Our second drilling project for 2004 was a 10% working interest in an 8,000-foot exploratory well that was basically only seismically defined. Since we perceived the LWMU a shallow, low risk project (92% working interest), we desired to combine that with a smaller interest in a deeper and higher risk project that could have the potential to discover a new field. Unfortunately that well did not result in any production for 2004, but technical analysis showed that it should be capable of production, possibly with horizontal technology. Even before drilling the well, the prospect partners were committed to running 3D seismic on the 2,000-acre prospect area. That seismic was completed in 2004, and from that a horizontal leg might be drilled in the existing well during 2005. As a result of most of our efforts being directed to the LWMU and not realizing any new production from our exploratory prospect, production declined at the approximate decline of all our wells for 2004 compared to 2003.

Although the production we sold was about 10% less in 2004 compared to 2003, the average value of our sales was dramatically higher leading to a significant increase in our oil and gas revenue. Revenue per BOE was higher in every quarter of 2004, from $2.13 higher in the first quarter to $13.78 higher in the fourth. Oil and gas prices were the single most important aspect of our operating performance and financial results during 2004. 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 8% in 2004, some of which directly relates to the higher oil and gas revenues, as production taxes are an "ad valorem" tax, a straight percentage of value produced at the wellhead. In 2004, $53,000 of the $136,000 increase in production costs was due to taxes. In addition, our expenses were generally higher in almost all categories due to the higher demand for oilfield goods and services. Also, the higher per Bbl revenue allowed us to increase discretionary spending. Those discretionary costs and taxes would be reduced if oil prices decrease. Discretionary costs reductions 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. The combination of lower production quantity and higher production costs resulted in 2004 average production cost per barrel increasing about 19% over 2003. Production costs and costs per BOE are one of the few financial areas we can control to a certain degree.

The margin between average revenue per BOE and average cost per BOE was $20.42 in 2004 compared to $13.32 in 2003. As a result, our gross margin for the oil and gas segment of our operations increased to $2.5 million in 2004 compared to $1.8 million for 2003. 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 2005 to be a year of high activity for us and the oil and gas industry. We have one drilling permit remaining from an un-drilled well we had budgeted for 2004 and a new permit in progress, both of which are in Bottineau County, ND. We believe many oil and gas operating companies intend to increase their exploration and production activities in 2005. That will strain the availability of oil and gas related labor, equipment and services which may adversely affect our ability to reach our goals.