REMINGTON OIL & GAS CORP
Form 10-K/A
December 16, 2003

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K/A
AMENDMENT NO. 1

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

FOR THE TRANSITION PERIOD FROM TO

COMMISSION FILE NUMBER 1-11516

REMINGTON OIL AND GAS CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	75-2369148
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer Identification No.)
8201 PRESTON ROAD, SUITE 600, DALLAS, TEXAS	75225-6211
(Address of principal executive offices)	(Zip code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(214) 210-2650

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

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, $0.01 Par Value	New York Stock Exchange

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

COMMON STOCK, $0.01 PAR VALUE

(Title of Class)

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

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

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

The aggregate market value of common stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, was $401,219,317. On March 27, 2003, the number of outstanding shares of common stock, $0.01 par value, was 26,399,437.

REMINGTON OIL AND GAS CORPORATION

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PART I

ITEM 1. BUSINESS.

GENERAL

Remington Oil and Gas Corporation

- Incorporated - 1991, Delaware

- Address - 8201 Preston Road, Suite 600, Dallas, Texas 75225-6211

- Telephone number - (214) 210-2650

- Website - www.remoil.net - Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website under the link "SEC Filings" as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

- 29 employees on December 31, 2002

We began operations in 1981 as OKC Limited Partnership. In 1992, the limited partnership was converted into a corporation named Box Energy Corporation. In 1997, we changed the name of the company to Remington Oil and Gas Corporation. We restructured our two classes of common stock into a single class of voting common stock when we merged with S-Sixteen Holding Company in December 1998.

Our primary business operation is exploration, development, and production of oil and gas reserves in the offshore Gulf of Mexico and onshore Gulf Coast areas. All of our assets are located in these areas and all of our revenues and expenses are generated in these same regions of the United States.

LONG-TERM STRATEGY

Our long-term strategy is to increase our oil and gas reserves and production while keeping our finding and development costs and operating costs competitive with our industry peers. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential. Our drilling program will contain some high risk/high reserve potential opportunities as well as some lower risk/lower reserve potential opportunities, in order to achieve a balanced program of reserve and production growth. Success of this strategy is contingent on various risk factors, as discussed in our filings with the Securities and Exchange Commission.

ACTIVITIES AND OPERATIONS

We identify prospective oil and gas properties primarily by using 3-D seismic technology. After acquiring an interest in a prospective property, we drill one or more exploratory wells. If the exploratory wells find commercial oil and/or gas, we complete the wells and begin producing the oil or gas.

Because most of our operations are located in the offshore Gulf of Mexico, we must install facilities such as offshore platforms and gathering pipelines in order to produce the oil and gas and deliver it to the marketplace. Certain properties require additional drilling to fully develop the oil and gas reserves and maximize the production from a particular discovery. In order to increase our oil and gas reserves and production, we continually reinvest our net operating cash flow into new or existing exploration, development and acquisition activities.

We share ownership in our oil and gas properties with various industry partners. We currently operate 66 of our offshore properties, while others operate the remainder of our properties. As operator, we are able to maintain a greater degree of control over the timing and amount of capital expenditures.

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RISKS INVOLVED IN EXPLORATION, DEVELOPMENT, AND PRODUCTION

Exploration, development, and production operations can be very risky. Each time we drill a well, there is a risk that the well will not find oil or gas reserves. If a well does find reserves, it is possible that the well will not produce enough oil or gas to return a profit on the amount invested in the well. We mitigate exploration and drilling risks by using 3-D seismic data and other applied technology to identify and define the parameters prior to drilling, although this does not guarantee successful results. Our success depends upon the quality of the information used to determine drilling locations and the abilities and experience of our management, technical, and service personnel.

Additional operating risks include mechanical failure, title risk, blowouts, environmental pollution, and personal injury. We maintain both general liability insurance and activity specific insurance against major production losses, blowouts, redrilling, and many other operating hazards, including certain pollution risks. Uninsured losses or losses and liabilities that exceed the limits of our insurance could adversely affect our financial condition.

COMPETITION IN THE OIL AND GAS INDUSTRY

We compete with:	We compete for:
- Large integrated oil and gas companies	- Operational, technical, and support staff
- Independent exploration and production companies	- Options and/or leases on properties
- Private individuals	- Sales of oil and gas production
- Sponsored drilling programs	- Access to capital

Many of our competitors may have significantly more financial, personnel, technological, and other resources available. In addition, some of the larger integrated companies may be better able to respond to industry changes including price fluctuations, oil and gas demands, and governmental regulations.

MARKETS FOR OIL AND GAS PRODUCTION

Oil and gas are generally homogenous commodities, and the market prices for these commodities fluctuate significantly. Purchasers adjust prices for quality, refined product yield, geographic proximity to refineries or major market centers, and the availability of transportation pipelines or facilities. Outside factors beyond our control combine to influence the market prices. Some of the more critical factors that affect oil and gas commodity prices include the following:

- Changes in supply and demand

- Changes in refinery utilization

- Levels of economic activity throughout the country

- Seasonal or extraordinary weather patterns

- Political developments throughout the world

We have no real ability to influence or predict the market prices. Therefore, we normally sell our oil and gas production based on posted market prices, spot market indices, or prices derived from the posted price or index. At times we will lock in a fixed price for a portion of our future production to be delivered as it is produced. An independent marketing company sells approximately 91% of our gas production. The revenue from the sale of gas by this marketing company accounted for approximately 54% of our total oil and gas revenues in 2002. In addition, we sold approximately 86% of our total oil production to two companies during the year, which accounted for approximately 36% of our total oil and gas revenues in 2002. Because other customers and marketers are available, we believe that the loss of any of these companies would not be detrimental to our operations nor have a material effect on our revenues.

GOVERNMENTAL REGULATION OF OIL AND GAS OPERATIONS AND ENVIRONMENTAL REGULATIONS

Numerous federal and state regulations affect our oil and gas operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability.

State regulations relate to virtually all aspects of the oil and gas business including drilling permits, bonds, and operation reports. In addition, many states have regulations relating to pooling of oil and gas properties, maximum rates of production, and spacing and plugging and abandonment of wells.

Our oil and gas operations are subject to stringent federal, state, and local environmental laws and regulations. Environmental laws and regulations are complex, change frequently, and have tended to become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may be commenced or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex, and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. The most significant environmental obligations applicable to our operations relate to compliance with the federal Oil Pollution Act and the Clean Water Act. The Oil Pollution Act and its implementing regulations ("OPA") establish requirements for the prevention of oil spills and impose liability for damages resulting from spills into waters of the United States. OPA also requires operators of offshore oil production facilities, such as our facilities in the Gulf of Mexico, to demonstrate to the U.S. Minerals Management Service that they possess at least $35.0 million in financial resources that are available to pay for costs that may be incurred in responding to an oil spill. The Clean Water Act and its implementing regulations impose restrictions and strict controls on the discharge of wastes into the waters of the United States, including discharges of oil, produced water and sand, drilling fluids, drill cuttings, and other wastes typically generated by the oil and gas industry. Although we believe that we are in compliance with the requirements of OPA, the Clean Water Act and other statutes governing the discharge of materials into the environment, the cost of compliance with this federal and state legislation could have a significant impact on our financial ability to carry out our oil and gas operations.

Our operations are also subject to environmental laws and regulations that impose requirements for remediation of soil and groundwater contamination. In many cases, these laws apply retroactively to previous waste disposal practices regardless of fault, legality of the original activities, or ownership or control of sites. A company could be subject to severe fines and cleanup costs if found liable under these laws. We have never been a liable party under these laws nor have we been named a potentially responsible party for waste disposal at any site. However, we do own and operate onshore properties that were previously owned and operated by companies whose waste disposal practices, while legal and standard within the industry at the time they occurred, may have resulted in on-site contamination that may require remedial action under current standards, and there can be no assurance that we will not be required to undertake remedial actions for such instances of contamination in connection with our ownership and operation of these properties.

OTHER BUSINESS INFORMATION

Except for our oil and gas leases with third parties and licenses to acquire or use seismic data, we have no material patents, licenses, franchises, or concessions that we consider significant to our oil and gas operations. We do not have any "backlog" of products, customer orders, or inventory. We have not been a party to any bankruptcy, reorganization, adjustment or similar proceeding except in the capacity as a creditor.

ITEM 2. PROPERTIES.

We concentrate our principal operations in the federal waters of the Gulf of Mexico and its coastal regions. In addition to the information below, we encourage you to read "Management's Discussion and Analysis of Financial Condition and Results of Operations" found on pages 9 through 18 and "Consolidated Financial Statements and Notes to Consolidated Financial Statements" found on pages 26 through 41. Note 2 - Oil and Gas Properties and Note 9 - Oil and Gas Reserves and Present Value Disclosures in our Notes to Consolidated Financial Statements provide detailed information concerning costs incurred, proved oil and gas reserves, and discounted future net revenue for proved reserves.

LEASEHOLD ACREAGE

Our leasehold acreage of oil and gas properties at December 31, 2002, was as follows:

	UNDEVELOPED	DEVELOPED

	GROSS	NET	GROSS	NET
Offshore.......................................	305,155	155,630	165,450	70,084
Onshore..	88,624	28,244	27,250	8,152
Total..	393,779	183,874	192,700	78,236

The current terms of leases on undeveloped acreage are scheduled to expire as shown in the table below. The term of a lease may be extended by drilling and production operations.

	FOR THE YEARS ENDED DECEMBER 31,								
	2003		2004		2005		2006 - BEYOND		
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET	G
Offshore............	5,000	4,375	0	0	20,278	11,264	279,877	139,991	30
Onshore.............	12,670	3,456	29,788	6,963	34,716	8,440	11,450	9,385	8
Total...............	17,670	7,831	29,788	6,963	54,994	19,704	291,327	149,376	39

PROVED OIL AND GAS RESERVES

Net proved oil and gas reserves at December 31, 2002, as evaluated by independent reserve engineers, Netherland, Sewell & Associates, Inc., are summarized below. The quantities of proved oil and gas reserves discussed in this section include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic and operating conditions. Proved reserves include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. Therefore, any changes in future prices, costs, regulations, technology or other unforeseen factors could materially increase or decrease the proved reserve estimates.

	NET OIL RESERVES MBBLS	NET GAS RESERVES MMCF
Offshore Gulf of Mexico....................................	8,952	118,651
Onshore Gulf Coast...	4,162	6,316
Total..	13,114	124,967

In 2002 our standardized measure of discounted future net cash flows was $351.0 million. We used December 31, 2002, West Texas Intermediate posted price of $28.00 per barrel and a Gulf Coast spot market price of $4.74 per MMBtu adjusted by property for energy content, quality, transportation fees, and regional price differentials. We estimated the costs based on the prior year costs incurred for individual properties or similar properties if a particular property did not produce during the prior year.

PRODUCING PROPERTIES

The table below summarizes our ownership in producing wells at the end of each of the last three years.

	AT DECEMBER 31,					
	2002		2001		2000	
	GROSS	NET	GROSS	NET	GROSS	NET
Oil wells						
Offshore Gulf of Mexico	25	8.67	21	6.72	14	3.57
Onshore Gulf Coast	32	12.89	35	13.61	29	11.13
Total	57	21.56	56	20.33	43	14.70
Gas wells						
Offshore Gulf of Mexico	35	11.19	38	11.02	29	7.68
Onshore Gulf Coast	75	18.52	97	23.65	85	20.92
Total	110	29.71	135	34.67	114	28.60

The decline in the gross number of wells from 2001 to 2002 is attributable to the sale of 8 wells and the discontinuance of production from a number of marginal wells.

Our offshore Gulf of Mexico properties account for approximately 80% of our oil production and approximately 92% of our gas production. In addition, total revenues from offshore Gulf of Mexico oil and gas production during 2002 accounted for approximately 89% of our total oil and gas revenues. We owned varying working interests (5% to 100%) in 94 offshore Gulf of Mexico blocks at December 31, 2002, and currently produce from 30 of these blocks. Three additional blocks are currently under development. We operate 17 of these 33 blocks. All of these blocks are located in water depths of less than 600 feet on the outer continental shelf of the Gulf of Mexico. In addition, we have invested in long-term 3-D seismic licensing agreements covering approximately 2,700 blocks in this area. Our agreements combined with our computer technology, provide our technical team immediate in-house access to these seismic data.

During 2002 we successfully drilled and completed 11 exploratory wells on 8 different properties in the offshore Gulf of Mexico. In addition, we, as operator, constructed and installed or will install 6 production platforms and drilled and completed 2 development wells on 2 different properties.

Our onshore Gulf Coast area properties are principally located in the State of Mississippi and along the Texas gulf coast. In 2002, these properties accounted for approximately 20% of our oil production and approximately 8% of our gas production. We drilled a total of 9 wells on our onshore properties during 2002 and completed 6 wells as producers. Our working interests in these wells range from 15% to 50%.

DRILLING ACTIVITIES

The following is a summary of our exploration and development drilling activities for the past three years.

	FOR THE YEARS ENDED DECEMBER 31,								
	2002				2001				
	GROSS		NET		GROSS		NET		GR
	PROD.	DRY	PROD.	DRY	PROD.	DRY	PROD.	DRY	PROD.
Exploratory									
Offshore Gulf of Mexico.......	11	4	5.28	1.66	13	2	4.77	0.91	12
Onshore Gulf Coast...........	5	3	1.66	0.75	9	3	2.81	0.90	18
Total........................	16	7	6.94	2.41	22	5	7.58	1.81	30
Development									
Offshore Gulf of Mexico.......	2	--	0.66	--	2	--	0.58	--	3
Onshore Gulf Coast...........	1	--	0.13	--	5	2	1.11	0.55	2
Total........................	3	--	0.79	--	7	2	1.69	0.55	5

We had an interest in 1 well (0.25 net) in progress at December 31, 2002, 2 wells (0.80 net) in progress at December 31, 2001, and 2 wells (0.65 net) in progress at December 31, 2000.

OTHER PROPERTY AND OFFICE LEASE

We own several non-contiguous tracts of land covering approximately 2,500 surface acres in Southern Louisiana and Southern Mississippi. We lease approximately 17,000 square feet of office space in Dallas, Texas. The lease on this office space expires in April 2008.

ITEM 3. LEGAL PROCEEDINGS.

We are not a party to any material legal proceedings at this time.

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

None

PART II

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

Our common stock trades on the New York Stock Exchange under the symbol REM. Prior to June 20, 2002, we traded on the Nasdaq National Market under the symbol ROIL and on the Pacific Exchange under the symbol REM.P. The following table sets forth the high and low closing price per share for the periods indicated.

	COMMON STOCK HIGH	COMMON STOCK LOW
2003		
First Quarter through March 27, 2003	19.75	16.63
2002		
Fourth Quarter	17.900	14.190
Third Quarter	19.450	13.460
Second Quarter	21.670	16.950
First Quarter	20.570	15.100
2001		
Fourth Quarter	18.350	13.030
Third Quarter	17.060	11.440
Second Quarter	19.190	12.125
First Quarter	16.250	11.625

On March 27, 2003, the last reported sales price for our common stock was $17.16 per share. On that date, there were 726 stockholders of record, including 92 stockholders of record of class A common stock and 107 stockholders of record of class B common stock who had not yet surrendered their old stock for the new common stock to which they are entitled.

In the early part of 2000, one of our subsidiaries, that at that time was 94%-owned by us, paid dividends in the amount of $17,000 to its minority shareholders. In 2000 the subsidiary acquired and retired the stock of the two minority holders. As a result, the subsidiary is now wholly-owned by us, and there is no longer the issue of dividends being paid by a subsidiary to persons outside the consolidated group. No dividends have ever been paid on our common stock. Our credit facility agreement prohibits our paying dividends. The determination of future cash dividends, if any, will depend upon, among other things, our financial condition,

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cash flow from operating activities, the level of our capital and exploration expenditure needs, future business prospects, and renegotiation of our line of credit.

The remaining information called for by this item relating to "Securities Authorized for Issuance under Equity Compensation Plans" is reported in Item 12, Security Ownership of Certain Beneficial Owners and Management, beginning on page 57 of this report.

ITEM 6. SELECTED FINANCIAL DATA.

The selected consolidated financial data should be read in conjunction with our consolidated financial statements and notes to the consolidated financial statements. In addition, you should also read our "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Item 7. below.

	2002(1)	2001(1)	2000(1)	1999	1998(1
	(IN THOUSANDS, EXCEPT PRICES, VOLUMES, AND PER SHARE DAT				
FINANCIAL					
Total revenue	$104,866	$ 116,620	$ 99,661	$ 44,348	$ 84,34
Net income (loss)	$ 11,332	$ 8,344	$ 45,044	$ (3,703)	$ 13,61
Basic income (loss) per share	$ 0.45	$ 0.38	$ 2.10	$ (0.17)	$ 0.6
Diluted income (loss) per share	$ 0.42	$ 0.35	$ 1.99	$ (0.17)	$ 0.6
Total assets	$288,993	$ 240,432	$192,474	$119,326	$130,22
8 1/4% convertible subordinated notes	$ --	$ --	$ 5,880	$ 5,950	$ 38,37
Other bank debt	$ 37,400	$ 71,000	$ 27,428	$ 30,028	$ 3,50
Stockholders' equity	$193,660	$ 125,338	$102,708	$ 56,054	$ 59,69
Total shares outstanding	26,236	22,651	21,564	21,285	21,24
Cash Flow					
Net cash flow from operations	$ 71,420	$ 99,025	$ 69,963	$ 19,180	$ 54,04
Net cash flow from investing	$(92,126)	$(119,242)	$(57,511)	$(25,911)	$(38,14
Net cash flow from financing	$ 16,258	$ 21,463	$ 1,323	$ (7,931)	$ (1,42
OPERATIONAL					
Proved reserves(2) Oil (MBbls)	13,114	13,865	10,370	7,177	5,51
Gas (MMcf)	124,967	111,920	88,650	65,508	52,70
Standardized measure of discounted future net cash flows - end of year(2)	$351,042	$ 199,983	$458,649	$126,868	$ 63,46
Average sales price(3)					
Oil (per Bbl)	$ 24.27	$ 23.29	$ 27.69	$ 15.50	$ 10.8
Gas (per Mcf)	$ 3.35	$ 4.02	$ 4.02	$ 2.45	$ 3.0
Average production (net sales volume)					
Oil (Bbls per day)	4,736	3,378	3,234	3,075	3,16
Gas (Mcf per day)	47,804	58,265	34,951	26,732	16,54

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(1) Financial results for 2002 include an $8.1 million charge for impairment of long-lived properties. For 2001 financial results include a $13.5 million charge for the final settlement of the Phillips Petroleum litigation and a $10.6 million charge for impairment of long-lived properties. The results for 2000 include $12.5 million gain on sale of certain South Texas properties, and for 1998 include $49.8 million in other income from the termination of our gas sales contract and an $18.0 million charge recorded for the Phillips Petroleum judgment.

(2) The quantities of proved oil and gas reserves discussed in this table include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic

and operating conditions. Proved reserves include only quantities that we can commercially recover using current prices, costs, and existing regulatory practices and technology. We base the standardized measure of discounted future net cash flows on year-end prices. Any changes in future prices, costs, regulations, technology, or other unforeseen factors could significantly increase or decrease the proved reserve estimates.

(3) We have not entered into any financial hedges for oil or gas prices during any of the years presented, therefore the average sales prices represent

actual sales revenue per barrel or Mcf.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion will assist you in understanding our financial position, liquidity, and results of operations. The information below should be read in conjunction with the financial statements, and the related notes to financial statements. Our discussion contains both historical and forward-looking information. We assess the risks and uncertainties about our business, long-term strategy, and financial condition before we make any forward-looking statements, but we cannot guarantee that our assessment is accurate or that our goals and projections can or will be met. Statements concerning results of future exploration, exploitation, development, and acquisition expenditures as well as expense and reserve levels are forward-looking statements. We make assumptions about commodity prices, drilling results, production costs, administrative expenses, and interest costs that we believe are reasonable based on currently available information.

LONG-TERM STRATEGY AND BUSINESS DEVELOPMENTS

Our long-term strategy is to increase our oil and gas reserves and production while keeping our finding and development costs and operating costs competitive with our industry peers. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential. Our drilling program will contain some high risk/high reserve potential opportunities as well as some lower risk/lower reserve potential opportunities, in order to achieve a balanced program of reserve and production growth. Success of this strategy is contingent on various risk factors, as discussed in our filings with the Securities and Exchange Commission. Over the last three years, we have invested $297.7 million in oil and gas properties, found 191.8 Bcfe of proved reserves and replaced 251% of our production at an average finding and development cost of $1.55 per Mcfe. The following table reflects our results during the last three years.

	2002	% INCREASE (DECREASE)	2001	% INCREASE (DECREASE)	2000
Production:					
Oil MBbls	1,729	40%	1,233	4%	1,1
Gas MMcf	17,448	(18)%	21,267	67%	12,7
Total MMcfe(1)	27,822	(3)%	28,665	44%	19,8
Proved reserves:					
Oil MBbls	13,114	(5)%	13,865	34%	10,3
Gas MMcf	124,967	12%	111,920	26%	88,6
Total MMcfe(1)	203,651	4%	195,110	29%	150,8
Operating costs per Mcfe	$ 0.58	4%	$ 0.56	10%	$ 0.
Finding costs per Mcfe(2)	$ 2.40	43%	$ 1.68	73%	$ 0.
Percentage of production replaced(3)	150%		253%		3

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(1) Barrels of oil are converted to Mcf equivalents (Mcfe) at the ratio of 1

barrel of oil equals 6 Mcf of gas.

(2) Finding costs include acquisition, development and exploration costs (including exploration costs such as seismic acquisition costs).

(3) Reserves sold (5.5 Bcfe in 2002 and 14.4 Bcfe in 2000) are excluded from this calculation.

CRITICAL ACCOUNTING POLICIES

We prepare our consolidated financial statements for inclusion in this report using accounting principles that are generally accepted in the United States ("GAAP"). Our Notes to Consolidated Financial Statements included on pages 26 through 41 in this report have a more comprehensive discussion of our significant accounting policies. GAAP represents a comprehensive set of accounting and disclosure rules and requirements. We must make judgments, estimates, and in certain circumstances, choices between acceptable GAAP alternatives as we apply these rules and requirements.

Successful Efforts Method of Accounting

Oil and gas exploration and production companies choose one of two acceptable accounting methods, successful-efforts or full cost. The most significant difference between the two methods relates to the accounting treatment of drilling costs for unsuccessful exploration wells ("dry holes") and exploration costs. Under the successful-efforts method, we recognize exploration costs and dry hole costs as an expense on the income statement when incurred and capitalize the costs of successful exploration wells as oil and gas properties. Entities that follow the full cost method capitalize all drilling and exploration costs including dry hole costs into one pool of total oil and gas property costs.

We use the successful-efforts method because we believe that it more conservatively reflects on our balance sheet historical costs that have future value. However, using successful-efforts often causes our income statement to fluctuate significantly between reporting periods based on our drilling success or failure during the periods.

It is typical for companies that drill a significant number of exploration wells, as we do, to incur dry hole costs. During the last three years we have drilled 86 exploration wells, of which 18 were considered dry holes. Our dry hole costs charged to expense during this period totaled $30.0 million out of total exploratory drilling costs of $124.8 million. It is impossible to predict future dry holes; however we estimate that between 20% and 30% of our exploration wells and exploration drilling costs will be dry holes, based on past experience.

Proved Reserve Estimates

Independent reserve engineers prepare our oil and gas reserve estimates using guidelines put forth under GAAP and by the Securities and Exchange Commission. The quality and quantity of data, the interpretation of the data, and the accuracy of mandated economic assumptions combined with the judgment exercised by the reserve engineers affect the accuracy of the estimated reserves. In addition, drilling or production results after the date of the estimate may cause material revisions to the reserve estimates. You should not assume that the present value of the future net cash flow disclosed in this report reflects the current market value of the oil and gas reserves. In accordance with the Securities and Exchange Commission's guidelines, we use prices and costs determined on the date of the estimate and a 10% discount rate to determine the present value of future net cash flow. Actual prices and costs may vary significantly, and the discount rate may or may not be appropriate based on outside economic conditions.

In our 2002 year-end reserve report we used December 31, 2002, West Texas Intermediate posted price of $28.00 per barrel and a Gulf Coast spot market price of $4.74 per MMBtu adjusted by property for energy content, quality, transportation fees, and regional price differentials. We estimated the costs based on the prior year costs incurred for individual properties or similar properties if a particular property did not have production during the prior year. While we believe that future costs can be reasonably estimated, future prices are difficult to estimate since the market prices are influenced by events beyond our control. Current world political events have caused oil prices to increase significantly since December 31, 2002. Future global economic and political events will most likely result in significant fluctuations in future oil prices. In addition, cold weather during the first quarter of 2003 in the United States has resulted in significant fluctuations in natural gas prices.

Depletion, Depreciation, and Amortization of Oil and Gas Properties

We calculate depletion, depreciation, and amortization expense ("DD&A") using the estimates of proved oil and gas reserves. We segregate the costs for individual or contiguous properties or projects and record DD&A of these property costs separately using the units of production method. Material downward revisions in reserves increase the DD&A per unit and reduce our net income; likewise, material upward revisions lower the DD&A per unit and increase our net income.

Impairment of Oil and Gas Properties

Because we account for our proved oil and gas properties separately, we assess our assets for impairment property by property rather than in one pool of total oil and gas property costs. This method of assessment is another feature of successful-efforts method of accounting. Certain unforeseeable events such as significantly decreased long-term oil or gas prices, failure of a well or wells to perform as projected, insufficient data on reservoir performance, and/or unexpected or increased costs may cause us to record an impairment expense on a particular property. We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. We estimate future prices based on NYMEX 12 month strips, adjusted for basis differential and escalate both the prices and the costs for inflation if appropriate. If these estimates indicate an impairment, we measure the impairment expense as the difference between the net book value of the asset and its estimated fair value measured by discounting the future net cash flow from the property at an appropriate rate. Actual prices, costs, discount rates, and net cash flow may vary from our estimates.

In 2002, we adopted Statement of Financial Accounting ("SFAS") Standards No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," which superseded SFAS No. 121 "Accounting for Impairment of Long-Lived Assets." The Statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. The adoption of this statement did not have a material effect on our balance sheet or income statement in 2002.

We recognized impairment expenses during the last three years as follows:

	FOR THE YEARS ENDED DECEMBER 31, 2002	2001	2000
	(IN THOUSANDS)		
Unproved properties	$1,640	$ 616	$811
Proved properties	6,441	10,000	48
Total impairment expense	$8,081	$10,616	$859

Through December 31, 2001, we assessed the capitalized costs of unproved properties periodically to estimate whether their value has been impaired below the capitalized costs, recognizing a loss to the extent such impairment was indicated. In making these estimations, we considered factors such as exploratory drilling results, future drilling plans and lease expiration terms. Effective January 1, 2002, we estimate the amount of individually insignificant unproved properties which will prove unproductive by amortizing the balance of our individually immaterial unproved property costs (adjusted by an anticipated rate of future successful development) over an average lease term. The effect of this change in estimate was not material to our results of operations. Individually significant properties will continue to be evaluated periodically on a separate basis for impairment. We will transfer the original cost of an unproved property to proved properties when we find commercial oil and gas reserves sufficient to justify full development of the property. The impairment of unproved properties for the prior two years primarily resulted from the actual (due to unsuccessful exploration results) or impending forfeiture of leaseholds.

We impaired proved properties for 2002 and 2001 because of insufficient future net cash flows based on the proved developed reserves as determined by our independent reserve engineers. The properties impaired in 2002, included two properties in the Gulf of Mexico which totaled $3.5 million and two in the onshore Gulf Coast which totaled $2.9 million. During 2001, we impaired three proved properties in the offshore Gulf of

Mexico that accounted for $8.7 million and one proved property in South Texas that accounted for $1.3 million of the total $10.0 million. The impairment expense on proved properties for 2000 resulted from insufficient oil and gas reserves on a small property in Alabama. None of the impairments discussed above were the result of prices causing lower proved reserves. The impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

Under the above critical accounting policies our net income can vary significantly from period to period because events or circumstances which trigger recognition as an expense for unsuccessful wells or impaired properties cannot be accurately forecast. In addition, selling prices for our oil and gas fluctuate significantly. Therefore we focus more on cash flow from operations and on controlling our finding and development, operating, administration, and financing costs.

Accounting for Stock Based Compensation

In June 1999, the Board of Directors approved contingent stock grants to our employees and directors. In order for the grants to become effective, the price of our stock had to increase from $4.19 per share to a trigger price of

$10.42 per share and close at or above $10.42 per share for 20 consecutive trading days. Further, the trigger price had to be achieved within 5 years of the grant date. This increase from $4.19 per share to $10.42 per share represented a compound annual rate of return of 20% for 5 years. On the grant date we did not record any amounts for expense, liability, or equity because the measurement date for determining the compensation cost depended on the occurrence of an event after the date of grant. Therefore, we could not be sure that we would incur any expense as a result of the grants, and we could not reasonably estimate the amount of possible expense.

January 24, 2001, became the measurement date when the stock price closed above the trigger price for the twentieth consecutive trading day. On that date, we measured the total compensation cost at $8.1 million which was the total number of shares granted multiplied by the market price on that date. We recorded $8.1 million as restricted common stock, $5.7 million as unearned compensation reported as a separate reduction in stockholders' equity on the balance sheet, and $2.4 million as stock based compensation expense. The $2.4 million stock based compensation expense recorded in the first quarter of 2001 included a "catch up" amortization from the date of the grant to the measurement date of the total compensation cost because the cost should be recognized over the time period in which the stock grant vested to the employees or directors. We recorded $3.5 million in 2001 and $1.4 million in 2002 as stock based compensation expense related to the grants. At December 31, 2002, $3.2 million of the unearned compensation remained unamortized and will be amortized as the shares vest during the next three years. The vesting period could accelerate in the event of a change in control of the company or the death or permanent disability of an employee. A shorter vesting period would accelerate the amortization period. Except as noted above, the shares will be issued only to the extent the employees and directors remain with the company through the vesting dates.

In accounting for stock options granted to employees and directors, we have chosen to continue to apply the accounting method promulgated by Accounting Principles Board Opinion ("APB") No. 25 rather than apply an alternative method permitted by SFAS No. 123. Under APB No. 25, at the time of grant we do not record compensation expense on our income statement for stock options granted to employees or directors. If we applied an alternative method permitted by SFAS No. 123, our net income would be lower than actually reported. We disclose in our Notes to Consolidated Financial Statements the pro-forma effect on our income statement if we were to record the estimated fair value of stock options on the date granted and amortize the expense over the expected vesting of the grant. We chose the APB No. 25 method because we believe that the true cost of options is reflected under this method. If and when the market price of the stock exceeds the option exercise price, the potential dilution is reflected in diluted earnings per share. We believe this dilution is the only true cost of the option. Further, we believe that also including a theoretical or estimated dollar expense in the income statement amounts to double-counting in calculating diluted income per share - subtracting an amount from the numerator and adding an amount to the denominator to reflect the same non-cash item.

Defined Benefit Pension Plan

Total assets at fair market value (public market prices for equity and fixed income mutual funds) for our two defined benefit pension plans were $4.5 million which exceeded the total accumulated benefit obligation as of December 31, 2002. We recorded $396,000 in pension expense and contributed $2.3 million to the plans during 2002. We have consistently used an 8% estimate for our long-term rate of return on plan assets and believe that this remains appropriate based on our plans' historical rates of return and on long-term historical rates of return for indices similar to our current plan asset allocation of equities (75%) and fixed income securities (25%). If however, we reduced the assumed rate of return by 50 basis points, our projected 2003 pension plan expense would increase by approximately $21,000 and our net income would decrease by approximately $14,000.

The discount rate is another critical assumption in determining pension liabilities and expenses. We are required to use a rate that approximates the market rate for high quality, long-term fixed income investments. Accordingly, we reduced our discount rate assumption from 7.25% in 2001 to 6.5% in 2002. A lower discount rate increases the calculated present value of benefit obligations and increases pension expense. If the discount rate decreases by 50 basis points, our projected 2003 pension expense would increase by approximately $268,000, and our net income would decrease by approximately $174,000.

LIQUIDITY AND CAPITAL RESOURCES

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2002.

	PAYMENTS DUE BY PERIOD				
	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTE YEA
			(IN THOUSANDS)		
Contractual obligations Bank debt............	$37,400	$ --	$37,400	$ --	$ -
Other long-term payables..................	$ 3,218	$1,715	$ 1,503	$ --	$ -
Office lease..............................	$ 2,468	$ 441	$ 920	$984	$12
Total......................................	$43,086	$2,156	$39,823	$984	$12

On December 31, 2002, our current assets exceeded our current liabilities by $3.2 million. Our current ratio was 1.07 to 1.00.

Cash flow provided by operations for the year ended December 31, 2002, decreased by $27.6 million, or 28%, compared to the prior year primarily due to changes in working capital accounts. We expect our cash flow provided by operations for 2003 to increase because of higher projected oil and gas prices, increased production from new properties, and consistent operating, general and administrative, and interest and financing costs per Mcf equivalent (Mcfe).

Our cash flow from operations fluctuates primarily because of changes in working capital accounts and variation in oil and gas production and prices, excluding the effects of significant unforeseen expenses or other income. Our oil and gas production will vary based on actual well performance or may be curtailed due to factors beyond our control. Hurricanes in the Gulf of Mexico will shut down our production for the duration of the storm, or as in the case of Hurricane Lili in 2002, damage production facilities so that we cannot produce a particular property for an extended amount of time. In addition, downstream activities on major pipelines in the Gulf of Mexico can also cause us to shut-in production for various lengths of time. Oil and gas prices will also vary significantly due to world political events, supply and demand of products, or weather patterns in the geographical United States. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility can significantly affect our cash flow. To mitigate effects of this volatility, we sometimes lock in prices for some portion of our production (usually less than 33%) through the use of forward sale agreements. See additional discussion under Commodity Price Risk in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Significant changes in our working capital accounts from 2001 to 2002 include an increase in our accounts receivable (a decrease in our cash flow provided by operations) due to higher oil and gas prices, increased production and increased balances due from our joint interest participants due to an increase in operating activities (drilling wells and facilities construction) at year end. Cash flow provided by operations decreased due to an increase in prepaid expenses and other current assets because of an increase in prepaid drilling costs on non-operated properties and increased pension plan contributions. In addition, due to the increase in operating activities our accounts payable increased by $13.3 million.

We incurred capital and exploration expenditures totaling $100.5 million during 2002. The capital expenditures included $4.2 million for leasehold acquisition, $45.4 million for exploration costs, $50.9 million for development costs including platform and facilities construction. During the year, we built and installed, or will install in 2003, 6 offshore platforms and facilities. In addition, in 2002 we drilled 23 exploration wells and 3 development wells.

We expect to continue to make significant capital expenditures over the next several years as part of our long-term growth strategy. We have budgeted $96.1 million for capital expenditures in 2003. Our 2003 capital and exploration budget includes $51.3 million for 30 exploratory wells. We project that we will spend $45.2 million on 21 wells in the Gulf of Mexico and $6.1 million on 9 onshore wells in South Texas and Mississippi. The budget also includes $25.8 million for platforms and development drilling on operated discoveries at South Marsh Island block 24, West Cameron blocks 416, 417 and 426, East Cameron block 185, and Eugene Island blocks 299, 302 and 397. The remaining $19.0 million will be allocated to leasehold acquisitions, seismic acquisitions, and workovers. We expect that our cash, estimated future cash flow from operations, and available bank line of credit will be adequate to fund these expenditures for the remainder of 2003.

If our exploratory drilling results in significant new discoveries, we will have to acquire additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the exploratory success and our record of reserve growth in recent years, we will be able to acquire sufficient additional capital through additional bank financing and/or offerings of debt or equity securities.

In March 2002 we issued 3.0 million shares of common stock at $18.50 per share. Net proceeds from the offering totaled approximately $52.8 million. We used $44.0 million of the net proceeds to reduce outstanding bank debt from $71.0 million to $27.0 million, and we used the remainder for working capital.

As of December 31, 2002, our amended credit facility has a borrowing base of $75.0 million. As of March 21, 2003, we had $37.4 million borrowed under the facility. The banks review the borrowing base semi-annually and may increase or decrease the borrowing base at their discretion relative to the new estimate of proved oil and gas reserves. The banks will reevaluate the borrowing base in April 2003. Our oil and gas properties are pledged as collateral for the line of credit. Additionally, we have agreed not to pay dividends. Unless renewed or extended, the line of credit expires on May 3, 2004, when all principal becomes due.

The most significant financial covenants in the line of credit include maintaining a minimum current ratio (as defined in the agreement) of 1.0 to 1.0, a minimum tangible net worth of $85.0 million plus 50% of net income (accumulated from the inception of the agreement) and 100% of any non-redeemable preferred or common stock offerings, and interest coverage of 3.0 to 1.0. We are currently in compliance with these financial covenants in all material respects. If we don't comply with these covenants, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

RESULTS OF OPERATIONS

In 2002, we recorded net income totaling $11.3 million or $0.45 basic income per share, and $0.42 diluted income per share, compared to a net income of $8.4 million or $0.38 basic income per share and $0.35 diluted income per share in 2001. The increase in net income resulted primarily from lower total costs and expenses,

primarily the $13.5 million settlement expense for Phillips Petroleum recorded in 2001. In addition, total revenues decreased by 10% primarily because of lower gas prices.

The following table discloses the net oil and gas production volumes, sales, and sales prices for each of the three years ended December 31, 2002, 2001, and 2000. The table is an integral part of the following discussion of results of operations for the periods 2002 compared to 2001 and 2001 compared to 2000.

	2002	% INCREASE (DECREASE)	2001	% INCREASE (DECREASE)	20
Oil production volume (MBbls)...............	1,729	40%	1,233	4%	1
Oil sales revenue..........................	$ 41,969	46%	$28,717	(12)%	$32
Price per Bbl..............................	$ 24.27	4%	$ 23.29	(16)%	$ 2
Increase (decrease) in oil sales revenue due to:					
Change in prices...........................	$ 1,208		$(5,196)		
Change in production volume................	12,044		1,229		
Total increase (decrease) in oil sales revenue..................................	$ 13,252		$(3,967)		
Gas production volume (MMcf)................	17,448	(18)%	21,267	67%	12
Gas sales revenue..........................	$ 58,412	(32)%	$85,504	67%	$51
Price per Mcf..............................	$ 3.35	(17)%	$ 4.02	0%	$
Increase (decrease) in gas sales revenue due to:					
Change in prices...........................	$ (14,249)		$ 0		
Change in production volume................	$ (12,843)		34,230		
Total increase (decrease) in gas sales revenue..................................	$ (27,092)		$34,230		

2002 compared to 2001

Oil sales revenue increased by $13.3 million, or 46%, because oil production increased by 496,000 barrels, or 40%, and average oil prices increased by $0.98 or 4%. Oil production from offshore Gulf of Mexico increased by 591,000 barrels, or 73%, because of production from new properties. Oil production from onshore gulf coast properties decreased by 95,000 barrels, or 21%, because of natural depletion of the existing producing properties and the sale of certain properties in South Texas in April 2002. Average prices increased from $23.29 in 2001 to $24.27 in 2002, which increased oil revenues by $1.2 million.

Gas sales revenue decreased by $27.1 million, or 32% because of lower average gas prices and lower production. Average gas prices decreased from $4.02 per Mcf in 2001 to $3.35 per Mcf, or 17%, in 2002, causing gas sales revenues to decrease by $14.2 million. Production decreased by 3.8 Bcf, or 18%, primarily because of lower gas production from the offshore Gulf of Mexico. During the fourth quarter of 2001 we lost production from a well on East Cameron block 364. The production from this property during 2001 was 3.1 Bcf compared to 0.3 Bcf during 2002. The decrease from this property was partially offset by increased gas production from new offshore properties.

Other income increased primarily because of a $4.1 million gain on the sale of certain immaterial South Texas properties in April 2002.

Total operating costs increased by $203,000 and operating costs per Mcfe increased by $0.02 to $0.58 during 2003.

Impairment expense for 2002 included a $6.4 million charge for impaired proved property costs and $1.6 million for amortization of unproved property costs. During 2001, we recorded $10.0 million for impairment charges of proved property costs and $616,000 for impairment of unproved property costs.

Exploration expenses increased by $2.5 million, or 19%, because of increased dry hole costs during 2002 partially offset by a $2.7 million decrease in seismic expenses in 2002 compared to 2001. Depreciation,

depletion and amortization expense increased by $265,000, or less than 1% for the year ended December 31, 2002, compared to the prior year. During 2002, depreciation, depletion and amortization increased to $1.38 per Mcfe from $1.33 per Mcfe in 2001.

General and administrative expenses decreased by $410,000, or 7%, due primarily to lower legal fees. Stock based compensation expense decreased by $2.1 million or 56% because in 2001 we included a "catch up" provision related to the contingent stock grants. The catch up included the period June 1999 (the date of the grant) to January 2001 (the date of measurement). The grant became effective in January 2001 when the requirements for the triggering of the stock grants were achieved. During the second quarter of 2001, we settled the Phillips litigation and charged $13.5 million to settlement expense. Interest and financing expense decreased because of lower interest rates and lower outstanding debt. Income taxes increased by $2.5 million as a result of increased income before taxes.

2001 compared to 2000

Oil production increased by 4% in 2001 compared to the prior year because of a 15% increase in offshore Gulf of Mexico production partially offset by lower oil production from Mississippi and South Texas. Oil production from the Gulf of Mexico increased because of new wells that began producing in 2001.

Average oil prices decreased 16% during 2001 which in turn caused oil sales revenues to be $5.2 million lower.

Gas sales revenue increased by $34.2 million or 67% because of a 67% increase in production compared to 2000. Production from the offshore Gulf of Mexico increased by 8.7 Bcf, or 101%, while gas production from South Texas decreased by 0.4 Bcf, or 7%. Five offshore properties began to produce for the first time during 2001 and three additional offshore properties increased their production significantly either from new wells drilled and completed or because 2001 was their first full year of production. We expected the decrease in production from South Texas after we sold certain properties in 2000. Average prices were unchanged.

Interest income decreased by $467,000, or 32% because of lower rates earned on our short-term investments and because we used the $9.0 million of restricted cash previously set aside for the Phillips Petroleum judgment in the settlement of that litigation in May 2001. Other income decreased because we had a non-recurring $12.5 million gain from the sale of South Texas properties in 2000.

Operating costs and expenses increased by $5.9 million, or 58%, because of new producing properties. Exploration expenses increased by $6.3 million, or 92%, because of increased dry hole costs for two offshore and one onshore well compared to six onshore wells in 2000. Offshore wells typically are significantly more costly than the onshore wells. The impairment expense for 2001 primarily resulted from insufficient future net cash flow for three offshore Gulf of Mexico properties, which accounted for $8.7 million, one South Texas property, which accounted for $1.3 million, and one unproved offshore Gulf of Mexico property lease that was forfeited in 2002 which accounted for $616,000. Depreciation, depletion and amortization expense increased by $17.3 million because of production from new properties.

General and administrative expenses have remained substantially level with prior year amounts. Stock based compensation expense includes $3.5 million for amortization of compensation costs related to the contingent stock grant and $246,000 for stock based directors fees.

On May 22, 2001, we settled the litigation with Phillips Petroleum Company. Of the total $42.5 million settlement, we had previously recorded $20.2 million as an accrued liability. We recorded $12.3 million of the remaining $22.3 million as additional settlement expense and capitalized $10.0 million as the cost for our purchase of the net profits interest. In addition, we charged the remaining $1.2 million deferred net profits expense related to a royalty settlement in 2000 to the settlement expense. During 2000, we reached two separate settlement agreements with the Minerals Management Service concerning claims for underpaid royalties due on offshore Gulf of Mexico properties. Because of the agreements, we recorded expenses of $5.4 million during 2000.

Interest and financing costs decreased 16% because of lower interest rates applicable to our outstanding debt and because we are no longer accruing interest on the Phillips judgment.

During 2001, we recorded income tax expense totaling $3.6 million, all of which is deferred. We fully utilized our net deferred income tax benefit during 2000 and the first quarter of 2001.

NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 143 "Accounting for Asset Retirement Obligations" will be effective for years beginning after June 15, 2002. The statement requires that we estimate the fair value for our asset retirement obligations (dismantlement and abandonment of oil and gas wells and offshore platforms) in the periods the assets are first placed in service. Currently we accrue the estimated liability for dismantlement and abandonment over the life of the property using a unit of production method. Because of this new standard, effective January 1, 2003, we must increase both our recorded assets and liabilities by the estimated cost of the ultimate asset retirement obligation. We will then increase the estimated obligation amount by contingency and inflation factors, and then discount the total amount to present value. Further, on a periodic basis we will record the accretion of the discount. For properties owned at December 31, 2002, we estimate the undiscounted asset retirement obligation to be approximately $15.0 million. We will also amortize the cost into depletion, depreciation, and amortization expense. The charges to the income statement will not be materially different under this standard as compared to our present method.

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148, "Accounting for Stock-Based Compensation -- Transition and Disclosure." SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition to SFAS No. 123's fair value method of accounting for stock-based employee compensation. SFAS No. 148 also amends the disclosure provisions of SFAS No. 123 and APB No. 28, "Interim Financial Reporting," to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. While SFAS No. 148 does not amend SFAS No. 123 to require companies to account for employee stock options using the fair value method, the disclosure provisions of SFAS No. 148 are applicable to all companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method of SFAS No. 123 or the intrinsic value method of APB No. 25. We disclose in our Notes to Consolidated Financial Statements the pro-forma effect on our income statement if we were to record the estimated fair value of stock options on the date granted and amortize the expense over the expected vesting of the grant.

SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Intangible Assets" became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. The appropriate application of SFAS Nos. 141 and 142 to oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves is unclear. Depending on how the accounting and disclosure literature is clarified, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. Additional disclosures required by SFAS Nos. 141 and 142 would be included in the notes to financial statements. Historically, we, like many other oil and gas companies, have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after SFAS Nos. 141 and 142 and became effective.

This interpretation of SFAS Nos. 141 and 142 would affect only our balance sheet classification of oil and gas leaseholds. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies."

At December 31, 2002, we had net leaseholds cost of approximately $35.8 million. If we applied the interpretation currently being deliberated, this classification would require us to make the disclosures set forth under SFAS No. 142 related to these interests. We will continue to classify our oil and gas leaseholds as oil and gas properties until further guidance is provided.

In June 2002, the Financial Accounting Standards Board issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses accounting and financial reporting for costs associated with certain exit or disposal activities. We do not anticipate initiating any activities that are subject to this standard.

Financial Accounting Standards Board Interpretation No. 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. We have no guarantees affected by this interpretation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

INTEREST RATE RISK

Our revolving bank line of credit is sensitive to changes in interest rates. At December 31, 2002, the unpaid principal balance under the line was $37.4 million which approximates its fair value. The interest rate on this debt is based on a premium of 150 to 225 basis points over the London Interbank Offered Rate ("Libor"). The rate is reset periodically, usually every three months. If on December 31, 2002, Libor changed by one full percentage point (100 basis points) the fair value of our revolving debt would change by approximately $93,000. We have not entered into any interest rate hedging contracts.

COMMODITY PRICE RISK

A vast majority of our production is sold on the spot markets. Accordingly, we are at risk for the volatility in the commodity prices inherent in the oil and gas industry.

Occasionally we sell forward portions of our production under physical delivery contracts that by their terms cannot be settled in cash or other financial instruments. Such contracts are not subject to the provisions of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities." Accordingly we do not provide sensitivity analysis for such contracts. For the period January 1, 2003, through March 31, 2003, we did not have any forward sales contracts in place. For the period April 1, 2003, through December 31, 2003, we have physical delivery contracts in place to sell 21,500 MMBtu of gas per day and 1,200 barrels of oil per day at the following prices:

	PRICE PER	
PERIOD	BARREL	MMBTU
April 1, 2003 through June 30, 2003	$30.92	$5.16
July 1, 2003 through September 30, 2003	$28.70	$4.89

October 1, 2003 through December 31, 2003.................	$27.41	$4.95

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To The Stockholders and Board of Directors of
Remington Oil and Gas Corporation

We have audited the accompanying consolidated balance sheet of Remington Oil and Gas Corporation ("the Company"), a Delaware corporation, as of December 31, 2002, and the related consolidated statements of income, stockholders' equity and cash flows for the year ended December 31, 2002. These consolidated 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. The financial statements of Remington Oil and Gas Corporation as of December 31, 2001, and for the two years in the period ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 15, 2002.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Remington Oil and Gas Corporation as of December 31, 2002, and the results of their operations and their cash flows for the year ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed above, the consolidated financial statements of Remington Oil and Gas Corporation as of December 31, 2001, and for the two years in the period ended December 31, 2001, were audited by other auditors who have ceased operations. As described in Note 1, these consolidated financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards (Statement) No. 148, Accounting for Stock Based Compensation -- Transition and Disclosure, which was adopted by the Company as of December 31, 2002. Our audit procedures with respect to the disclosures in Note 1 for 2001 and 2000 included (a) agreeing the as reported and proforma net income, as reported and proforma basic earnings per share, and as reported and proforma diluted earnings per share to the previously issued financial statements, (b) agreeing the stock based employee compensation expense (including any related tax effects) determined under a fair value method for all awards to the Company's underlying records obtained from management, and (c) testing the mathematical accuracy of the reconciliation of proforma net income to reported net income. In our opinion, the disclosures for 2001 and 2000 in Note 1 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 and 2000 consolidated financial statements of the Company other than with respect to such disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

/s/ ERNST & YOUNG LLP

Dallas, Texas
March 24, 2003

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THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To The Stockholders and Board of Directors of Remington Oil and Gas Corporation

We have audited the accompanying balance sheets of Remington Oil and Gas Corporation ("the Company"), a Delaware corporation, as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity and cash flows for the three years in the period ended December 31, 2001. These consolidated 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. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Remington Oil and Gas Corporation as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Dallas, Texas
March 15, 2002

The above is a copy of the Report of Independent Public Accountants issued by Arthur Andersen LLP in connection with Remington Oil and Gas Corporation's filing of an annual report on Form 10-K for the year ended December 31, 2001. Arthur Andersen LLP has not reissued its Report in connection with the filing of the Company's annual report on Form 10-K for the year ended December 31, 2002, nor has Arthur Andersen LLP consented to the inclusion of their Report in this annual report on Form 10-K. Arthur Andersen LLP has ceased practicing before the Securities and Exchange Commission. See Exhibit 23.2 for further discussion. The consolidated balance sheet as of December 31, 2000, and the consolidated statements of income, stockholders' equity, and cash flows for the year ended December 31, 1999, have not been included in the accompanying financial statements.

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED BALANCE SHEETS

	AT DECEMBER 31,	
	2002	2001
	(IN THOUSANDS, EXCEPT SHARE DATA)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14,929	$ 19,377
Accounts receivable	32,555	19,445
Prepaid drilling costs	3,115	400
Prepaid expenses and other current assets	1,863	1,087
TOTAL CURRENT ASSETS	52,462	40,309
PROPERTIES		
Oil and gas properties (successful-efforts method)	510,921	433,988
Other properties	3,182	3,023
Accumulated depreciation, depletion and amortization	(279,722)	(237,661)
TOTAL PROPERTIES	234,381	199,350
OTHER ASSETS		
Other assets	2,150	773
TOTAL OTHER ASSETS	2,150	773
TOTAL ASSETS	$ 288,993	$ 240,432
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 47,523	$ 34,232
Short-term notes payable and current portion of other long-term payables	1,715	3,253

TOTAL CURRENT LIABILITIES	49,238	37,485
LONG-TERM LIABILITIES		
Notes payable	37,400	71,000
Other long-term payables	1,503	3,758
Deferred income taxes	7,192	2,851
TOTAL LONG-TERM LIABILITIES	46,095	77,609
TOTAL LIABILITIES	95,333	115,094
COMMITMENTS AND CONTINGENCIES (NOTE 4)		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value, 25,000,000 shares authorized Shares issued -- none		
Common stock, $.01 par value, 100,000,000 shares authorized, 26,327,195 shares issued and 26,236,459 shares outstanding in 2002, 22,685,240 shares issued and 22,650,881 shares outstanding in 2001	263	227
Additional paid-in capital	115,827	56,698
Restricted common stock	5,468	8,055
Unearned compensation	(3,192)	(4,581)
Treasury stock (56,377 shares common stock in 2002, at cost)	(977)	--
Retained earnings	76,271	64,939
TOTAL STOCKHOLDERS' EQUITY	193,660	125,338
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 288,993	$ 240,432

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
REVENUES			
Oil sales	$ 41,969	$ 28,717	$ 32,684
Gas sales	58,412	85,504	51,274
Interest income	198	975	1,442
Gain on sale of assets and other income	4,287	1,424	14,261
Total revenues	104,866	116,620	99,661
COSTS AND EXPENSES			
Operating costs and expenses	16,150	15,947	10,092
Exploration expenses	15,623	13,100	6,833
Depreciation, depletion, and amortization	38,528	38,263	20,976

Impairment of oil and gas properties	8,081	10,616	859
General and administrative	6,912	9,409	5,785
Settlements expense	--	13,524	5,416
Interest and financing expense	2,145	3,829	4,561
TOTAL COSTS AND EXPENSES	87,439	104,688	54,522
INCOME BEFORE TAXES	17,427	11,932	45,139
Income taxes	6,095	3,588	100
Minority interest	--	--	(5)
NET INCOME	$ 11,332	$ 8,344	$ 45,044
BASIC INCOME PER SHARE	$ 0.45	$ 0.38	$ 2.10
DILUTED INCOME PER SHARE	$ 0.42	$ 0.35	$ 1.99

See accompanying Notes to Consolidated Financial Statements.

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(IN THOUSANDS)

	COMMON STOCK $0.01 PAR VALUE	ADDITIONAL PAID IN CAPITAL	RESTRICTED COMMON STOCK	UNEARNED COMPENSATION	TREASURY STOCK
Balance December 31, 1999	$213	$ 44,273	$ --	$ --	$ --
Net income	--	--	--	--	--
Common stock issued	3	1,624	--	--	--
Dividends paid to minority stockholders of a consolidated subsidiary	--	--	--	--	--
Balance December 31, 2000	216	45,897	--	--	--
Net income	--	--	--	--	--
Contingent stock grant	--	--	8,055	(8,055)	--
Amortization of unearned compensation	--	--	--	3,474	--
Common stock issued	22	30,640	--	--	--
Tax benefit from exercise of stock options	--	794	--	--	--
Common stock repurchased and retired	(11)	(20,633)	--	--	--
Balance December 31, 2001	227	56,698	8,055	(4,581)	--
Net income	--	--	--	--	--
Amortization of unearned compensation	--	--	--	1,389	--
Common stock issued	36	57,375	(2,587)	--	--
Tax benefit from exercise of					

stock options...............	--	1,754	--	--	--
Common stock repurchased.......	--	--	--	--	(977)
Balance December 31, 2002......	$263	$115,827	$ 5,468	$(3,192)	$(977)

See accompanying Notes to Consolidated Financial Statements.

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
CASH FLOW PROVIDED BY OPERATIONS			
NET INCOME...	$ 11,332	$ 8,344	$ 45,044
Adjustments to reconcile net income			
Depreciation, depletion, and amortization................	38,528	38,263	20,976
Deferred income tax expense............................	6,095	3,600	--
Amortization of deferred finance charges.................	228	172	334
Deferred net profits expense............................	--	1,270	--
Impairment of oil and gas properties....................	8,081	10,616	859
Dry hole costs...	14,828	9,589	5,557
Cash paid for dismantlement and restoration liability.....	(247)	(622)	--
Minority interest in net income of subsidiaries..........	--	--	(5)
Stock based compensation................................	1,609	3,696	174
Royalty settlement......................................	--	--	5,416
Gain on sale of properties..............................	(4,095)	(201)	(12,640)
CHANGES IN WORKING CAPITAL			
Decrease (increase) in accounts receivable...............	(13,099)	1,580	(14,745)
Decrease (increase) in prepaid expenses and other current assets...	(5,131)	526	344
Increase in accounts payable and accrued expenses.........	13,291	10,600	19,199
Decrease (increase) in restricted cash....................	--	11,592	(550)
NET CASH FLOW PROVIDED BY OPERATIONS.......................	71,420	99,025	69,963
CASH FROM INVESTING ACTIVITIES			
Payments for capital expenditures........................	(99,865)	(119,673)	(72,678)
Proceeds from property sales.............................	7,739	431	15,167
NET CASH (USED IN) INVESTING ACTIVITIES....................	(92,126)	(119,242)	(57,511)
CASH FROM FINANCING ACTIVITIES			
Proceeds from notes payable and long-term accounts payable..	17,000	51,500	10,630
Payments on notes payable and long-term accounts payable..	(54,393)	(12,464)	(9,811)
Purchase common stock....................................	(977)	(20,644)	--
Commitment fee on line of credit.........................	--	(307)	--

Common stock issued	54,628	3,378	521
Dividends paid to minority stockholders of a consolidated subsidiary	--	--	(17)
NET CASH PROVIDED BY FINANCING ACTIVITIES	16,258	21,463	1,323
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,448)	1,246	13,775
Cash and cash equivalents at beginning of period	19,377	18,131	4,356
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 14,929	$ 19,377	$ 18,131
Cash paid for interest	$ 2,552	$ 2,925	$ 4,338
Cash paid (received) for taxes	$ --	$ (12)	$ 100
Non-cash issuance of common stock (Note 6)	$ --	$ 21,250	$ --

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

Remington Oil and Gas Corporation, formerly Box Energy Corporation, is an independent oil and gas exploration and production company incorporated in Delaware. We have working interest ownership rights in properties in the offshore Gulf of Mexico and onshore Gulf Coast. We acquired the following subsidiaries in 1998: CKB Petroleum, Inc., CKB & Associates, Inc., Box Brothers Realty Investments Company, CB Farms, Inc., and Box Resources, Inc. We consolidate 100% of the assets, liabilities, equity, income and expense of the subsidiaries and eliminate all inter-company transactions and account balances for the periods of consolidation. We own 100% of the outstanding capital stock of all of the subsidiaries. The primary operating subsidiary, CKB Petroleum, Inc., owns an undivided interest in a pipeline that transports our oil from our South Pass blocks, offshore Gulf of Mexico, to Venice Louisiana. We account for our undivided interests in properties using the proportionate consolidation method, whereby our share of assets, liabilities, revenues and expenses are included in our financial statements.

USE OF ESTIMATES IN THE PREPARATION OF FINANCIAL STATEMENTS

Management prepares the financial statements in conformity with accounting principles generally accepted in the United States. This requires estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported periods. Some of the more significant estimates include oil and gas reserves, useful lives of assets, impairment of oil and gas properties, and future dismantlement and restoration liabilities. Actual results could differ from those estimates. We make certain reclassifications to prior year financial statements in order to conform to the current year presentation.

CASH, CASH EQUIVALENTS, AND RESTRICTED CASH

Cash equivalents consist of highly liquid investments that mature within three months or less when purchased. Our cash equivalents include investment grade commercial paper and institutional money market funds. We record cash equivalents at cost, which approximates their market value at the balance sheet date.

CONCENTRATION OF CREDIT RISK

Our financial instruments that are potentially subject to a concentration of credit risk are principally cash and trade receivables. We have cash deposits at two institutions that exceed the $100,000 federally insured limit by $14.8 million and $19.3 million at December 31, 2002 and 2001, respectively. At December 31, 2002, 3 companies accounted for approximately 58% of the total accounts receivable, and at December 31, 2001, 4 companies accounted for approximately 81% of the total accounts receivable. In 2002, gas sales by a gas marketing company accounted for approximately 54% of our total oil and gas revenue. In addition, oil sales to one company accounted for approximately 23% of our total oil and gas revenues in 2002 and oil sales to a second company accounted for approximately 11% of our total oil and gas revenues in 2002. The revenue from the sale of oil and gas by the gas marketing company accounted for approximately 65% of our total oil and gas revenues in 2001. In addition, we sold approximately 56% of our total oil production to one company during the year, which accounted for approximately 14% of our total oil and gas revenues in 2001. We do not believe that the loss of services or sales from any of these companies would have a material adverse effect on us due to the fungible nature of the oil and gas production for which there is high and growing demand and numerous customers that can easily be replaced.

PROPERTY AND EQUIPMENT

We follow the successful-efforts method to account for oil and gas exploration and development expenditures. Under this method, we capitalize expenditures for leasehold acquisitions, drilling costs for productive wells and unsuccessful development wells. We amortize the capitalized costs using the units-of-production method, converting to gas equivalent units by using the ratio of 6 barrels of oil equal to one thousand cubic feet of gas. Future dismantlement, restoration and abandonment costs include the estimated costs to dismantle, restore, and abandon our offshore platforms, wells, and related facilities. We accrue for the liability over the life of the property using the units-of-production method and record the expense as a component of depreciation, depletion and amortization expense. As of December 31, 2002, the total estimated liability of our future dismantlement and restoration costs is approximately $15.0 million. The accrued liability at December 31, 2002 and 2001, was $5.7 million and $4.3 million, respectively. We record expenditures for geological, geophysical or other prospecting costs as exploration expenses on the income statement when incurred.

Periodically, if there is a large decrease in oil and gas reserves or production on a property, or if a dry hole is drilled on or near one of our properties we will review the properties for impairment. In addition, significant decreases in long-term oil and gas prices may also indicate that a property has become impaired. If the net book value of a property is greater than the estimated undiscounted future net cash flow from the same property, the property is considered impaired. We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. The impairment expense is equal to the difference between the net book value and the fair value of the asset. We estimate fair value by discounting, at an appropriate rate, the future net cash flows from the property. In addition, we assess the capitalized costs of unproved properties periodically to determine whether their value has been impaired below the capitalized costs. We recognize a loss to the extent that such impairment is indicated. In making these assessments, we consider factors such as exploratory drilling results, future drilling plans, and lease expiration terms.

Other properties include improvements on the leased office space and office computers and equipment. The company depreciates these assets using the straight-line method over their estimated useful lives that range from 3 to 12 years.

OTHER ASSETS

Other assets include the long-term portion of prepaid pension expenses (see Note 7. Employee and Director Benefit Plans -- Pension Plan), and net unamortized credit facility origination fees. The origination fees are amortized on a straight-line basis over the term of the debt. We charge the amortized amount to interest and financing costs. In addition, other assets also include a long-term account receivable totaling $366,000, which is CKB Petroleum's claim under Collateral Assignment Split Dollar Insurance Agreements among CKB Petroleum and Don D. Box (an officer and director) and two of his brothers.

The amount due CKB Petroleum from Don D. Box under the Collateral Assignment Split Dollar Insurance Agreement was $140,000 on December 31, 2002, and $135,000 on December 31, 2001.

ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses were as follows:

	AT DECEMBER 31,	
	2002	2001
	(IN THOUSANDS)	
Accounts payable - trade	$32,908	$25,907
Advance billings	8,353	5,374
Royalties and other revenue payable	5,850	2,428
Other current payables	412	523
Total accounts payable and accrued expenses	$47,523	$34,232

OIL AND GAS REVENUES

When oil and gas is produced, we sell it immediately. Consequently, we recognize oil and gas revenue in the month of actual production based on our share of the revenues. Our actual sales have not been materially different from our entitled share of production, and we do not have any significant gas imbalances.

TRANSPORTATION COSTS

We include transportation costs in operating costs and expenses. During the years ended December 31, 2002, 2001, and 2000, we incurred transportation costs totaling $2.1 million, $1.6 million and $313,000, respectively.

STOCK OPTIONS

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148, "Accounting for Stock-Based Compensation -- Transition and Disclosure." SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition to SFAS No. 123's fair value method of accounting for stock-based employee compensation.

SFAS No. 148 also amends the disclosure provisions of SFAS No. 123 and APB No. 28, "Interim Financial Reporting," to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. While SFAS No. 148 does not amend SFAS No. 123 to require companies to account for employee stock options using the fair value method, the disclosure provisions of SFAS No. 148 are applicable to all companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method of SFAS No. 123 or the intrinsic value method of APB No. 25.

We continue to apply the accounting provisions of Accounting Principles Board Opinion 25, entitled "Accounting for Stock Issued to Employees," and related interpretations to account for stock-based compensation and have adopted the disclosure requirements of SFAS 123 and SFAS 148 as of December 31, 2002. Accordingly, we measure compensation cost for stock options as the excess, if any, of the quoted market price of our stock at the date of the grant over the amount an employee must pay to acquire the stock. All of our options are granted with exercise prices at or above the quoted market price on the date of grant.

The following table summarizes relevant information as to the reported results under our intrinsic value method of accounting for stock awards, with supplemental information as if the fair value recognition provision of SFAS No. 123 had been applied:

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
As reported:			
Net income	$11,332	$8,344	$45,044
Basic income per share	$ 0.45	$ 0.38	$ 2.10
Diluted income per share	$ 0.42	$ 0.35	$ 1.99
Stock based compensation (net of tax) included in net income as reported	$ 1,046	$2,402	$ 113
Stock based compensation (net of tax) if using the fair			

value method as applied to all awards	$ 2,531	$4,248	$ 1,271
Proforma (if using the fair value method applied to all awards):			
Net income	$ 9,847	$6,498	$43,886
Basic income per share	$ 0.39	$ 0.30	$ 2.05
Diluted income per share	$ 0.36	$ 0.27	$ 1.94
Weighted average shares used in computation			
Basic	25,294	21,979	21,435
Diluted	27,122	24,414	22,759

The fair value of each option grant for the years ended December 31, 2002, 2001, and 2000 is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
Expected life (years)	10	10	10
Interest rate	4.17%	5.13%	6.18%
Volatility	61.62%	62.56%	59.01%
Dividend yield	0%	0%	0%

As required, the pro-forma disclosures above include options granted since January 1, 1995. Consequently, the effects of applying SFAS No. 123 for providing pro-forma disclosures may not be representative of the effects on reported net income for future years until all options outstanding are included in the pro-forma disclosures. For purposes of pro-forma disclosures, the estimated fair value of stock-based compensation plans and other options are amortized to expense primarily over the vesting period.

SEGMENT REPORTING

We operate in only one business segment.

ADOPTED AND NEW ACCOUNTING POLICIES

In 2002, we adopted Statement of Financial Accounting Standards No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," which superceded Statement of Financial Accounting Standards No. 121 "Accounting for Impairment of Long-Lived Assets." The Statement addressed financial accounting and reporting for the impairment or disposal of long-lived assets. The adoption of this statement did not have a material effect on our balance sheet or income statement in 2002.

Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" will be effective for years beginning after June 15, 2002. The statement requires that we estimate the fair value for our asset retirement obligations (dismantlement and abandonment of oil and gas wells and offshore platforms) in the period in which the asset is first placed in service.

Currently we accrue the estimated liability for dismantlement and abandonment over the life of the property using a unit of production method. Because of this new standard, effective January 1, 2003, we must increase both our recorded assets and liabilities by the estimated cost of the ultimate asset retirement obligation. We will then increase the estimated obligation amount by contingency and inflation factors and then discount the total amount to present value. Further, on a periodic basis we will record the accretion of the discount. For properties owned at December 31, 2002, we estimate that amount to be approximately $15.0 million. We will also amortize the cost into depletion, depreciation, and amortization expense. The charges to the income statement will not be materially different under this standard as compared to our present method.

GENERAL AND ADMINISTRATIVE EXPENSES

We report our general and administrative expenses net of reimbursed overhead costs that we allocate to working interest owners of the oil and gas properties that we operate.

INCOME TAXES

Income tax expense or benefit includes both the current income taxes and deferred income taxes. Current income tax expense or benefit equals the amount expected to be calculated on our income tax return for that year. Deferred income tax expense or benefit equals the change in the net deferred income tax asset or liability from the beginning of the year to the end of the year. We determine the amount of our deferred income tax asset or liability by multiplying the enacted tax rate by the temporary differences, net operating or capital loss carry-forwards plus any tax credit carry-forwards. The tax rate used is the effective rate applicable for the year in which we expect the temporary differences or carry-forwards to reverse. A valuation allowance offsets deferred income tax assets that are not expected to reverse in future years.

INCOME PER COMMON SHARE

We compute basic income per share by dividing net income by the weighted average number of common shares outstanding for the period. Diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted

in the issuance of common stock that then shares in the net income of the company. The following table presents our calculation of basic and diluted income per share.

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		

Net income available for basic income per share	$11,332	$8,344	$45,044
Interest expense on Convertible Notes (net of tax)	--	188	318
Net income available for diluted income per share	$11,332	$8,532	$45,362
Basic income per share	$ 0.45	$ 0.38	$ 2.10
Diluted income per share	$ 0.42	$ 0.35	$ 1.99
Weighted average common shares for basic income per share	25,294	21,979	21,435
Dilutive stock options outstanding (treasury stock method)	1,378	1,453	784
Common stock grant	450	663	--
Shares assumed issued by conversion of the Notes	--	319	540
Total common shares for diluted income per share	27,122	24,414	22,759
Potential issues of common stock for diluted income per share Weighted average shares from warrant issued in merger	--	--	200

NOTE 2 -- OIL AND GAS PROPERTIES

The following table summarizes the capitalized costs on our oil and gas properties, all of which are located in the United States.

	AT DECEMBER 31,					
	2002			2001		
	PROVED	UNPROVED	TOTAL	PROVED	UNPROVED	TOTAL
	(IN THOUSANDS)					
Onshore	$ 58,227	$ 3,511	$ 61,738	$ 55,190	$ 3,189	$ 58,379
Offshore	432,103	17,080	449,183	357,137	18,472	375,609
Total	490,330	20,591	510,921	412,327	21,661	433,988
Accumulated depreciation, depletion and amortization	(277,330)	--	(277,330)	(235,428)	--	(235,428)
Net oil and gas properties	$ 213,000	$20,591	$ 233,591	$ 176,899	$21,661	$ 198,560

SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Intangible Assets" became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. The appropriate application of SFAS Nos. 141 and 142 to oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves is unclear. Depending on how the accounting and disclosure literature is clarified, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible

assets on our balance sheets. Additional disclosures required by SFAS Nos. 141 and 142 would be included in the notes to financial statements. Historically, we, like many other oil and gas companies, have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after SFAS Nos. 141 and 142 and became effective.

This interpretation of SFAS Nos. 141 and 142 would affect only our balance sheet classification of oil and gas leaseholds. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies."

At December 31, 2002, we had net leaseholds cost of approximately $35.8 million. If we applied the interpretation currently being deliberated, this classification would require us to make the disclosures set forth under SFAS No. 142 related to these interests. We will continue to classify our oil and gas leaseholds as oil and gas properties until further guidance is provided.

The following table presents a summary of our oil and gas expenditures during the last three years.

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(UNAUDITED, IN THOUSANDS)		
Unproved acquisition costs	$ 4,215	$ 9,885	$13,057
Proved acquisition costs	--	5,000	1,779
Exploration costs	45,381	46,825	38,224
Development costs	50,904	61,145	21,249
Total	$100,500	$122,855	$74,309

We recognized impairment expenses as follows in the table below:

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		

Unproved properties	$ 1,640	$ 616	$ 811
Proved properties	6,441	10,000	48
Total impairment expense	$ 8,081	$ 10,616	$ 859

Through December 31, 2001, we assessed the capitalized costs of unproved properties periodically to estimate whether their value has been impaired below the capitalized costs, recognizing a loss to the extent such impairment was indicated. In making these estimations, we considered factors such as exploratory drilling results, future drilling plans and lease expiration terms. Effective January 1, 2002, we estimate the amount of individually insignificant unproved properties which will prove unproductive by amortizing the balance of our individually immaterial unproved property costs (adjusted by an anticipated rate of future successful development) over an average lease term. The effect of this change in estimate was not material to our results of operations. Individually significant properties will continue to be evaluated periodically on a separate basis for impairment. We will transfer the original cost of an unproved property to proved properties when we find commercial oil and gas reserves sufficient to justify full development of the property. The impairment of unproved properties for the prior two years primarily resulted from the actual (due to unsuccessful exploration results) or impending forfeiture of leaseholds.

We impaired proved properties for 2002 and 2001 because of insufficient future net cash flows based on the proved developed reserves as determined by our independent reserve engineers. In order to determine the amount of impairment on properties, we estimate future prices based on NYMEX 12 month strips adjusted

for basis differences and escalate both the prices and the costs for inflation if appropriate. The properties impaired in 2002, included two properties in the Gulf of Mexico which totaled $3.5 million and two on the onshore Gulf Coast which totaled $2.9 million. During 2001, we impaired three proved properties in the offshore Gulf of Mexico that accounted for $8.7 million and one proved property in South Texas that accounted for $1.3 million of the total $10.0 million. The impairment expense on proved properties for 2000 resulted form insufficient oil and gas reserves on one small property in Alabama.

NOTE 3 -- NOTES PAYABLE AND OTHER LONG-TERM PAYABLES

BANK CREDIT FACILITY

As of December 31, 2002, our amended credit facility of $150.0 million has a borrowing base of $75.0 million. The following schedule reflects certain information about the line of credit for the last two years.

	AT DECEMBER 31,	
	2002	2001
	(IN THOUSANDS)	

Borrowing base	$75,000	$75,000
Outstanding balance	37,400	71,000
Available amount	$37,600	$ 4,000

We pledged our oil and gas properties as collateral for this line of credit. We accrue and pay interest at varying rates based on premiums ranging from 1.5 to 2.25 percentage points over the London Interbank Offered Rates. Interest only is payable quarterly through May 3, 2004, at which time the line expires and all principal becomes due, unless the line is extended or renegotiated.

The most significant financial covenants in the line of credit include, among others, maintaining a minimum current ratio (as defined in the agreement) of 1.0 to 1.0, a minimum tangible net worth of $85.0 million plus 50% of net income (accumulated from the inception of the agreement) and 100% of any non-redeemable preferred or common stock offerings, and interest coverage of 3.0 to 1.0. We are currently in compliance with these financial covenants in all material respects. If we don't comply with these covenants, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

The banks review the borrowing base semi-annually and may increase or decrease the borrowing base at their discretion relative to the new estimate of proved oil and gas reserves. The next redetermination is scheduled for April 2003.

OTHER

Other long-term payables include certain vender financing arrangements.

FAIR VALUE OF INDEBTEDNESS

We estimate that the fair value of our long-term indebtedness, including the current maturities of such obligations, is approximately $40.6 million at December 31, 2002 and $78.0 million at December 31, 2001. We based the fair value on current rates available for our bank debt. The book value of our other long-term indebtedness approximates fair value.

NOTE 4 -- COMMITMENTS AND CONTINGENT LIABILITIES

We lease approximately 17,000 square feet of office space in Dallas, Texas. The non-cancelable operating lease expires in April 2008. The following table reflects our rent payments for the past three years and the commitment for the future minimum rental payments.

YEAR	RENT($)
2000	407,000
2001	433,000
2002	441,000

2003	441,000
2004	441,000
2005	479,000
2006	492,000
2007	492,000
Remaining commitment	123,000

We have no material pending legal proceedings.

NOTE 5 -- COMMON STOCK, PREFERRED STOCK AND DIVIDENDS

In 1998, we increased the number of authorized common stock shares to 100.0 million and authorized 25.0 million shares of "blank check" preferred stock. The par value of the common stock and preferred stock is $0.01 per share. The board of directors can approve the issue of multiple series of preferred stock and set different terms, voting rights, conversion features, and redemption rights for each distinct series of the preferred stock.

We have reserved approximately 4.0 million shares of common stock for our stock option plan and for our non-employee director stock purchase plan, which are discussed in more detail in Note 7 -- Employee and Director Benefit Plans. Dividend payments are currently prohibited by our line of credit agreement.

In the early part of 2000, one of our subsidiaries, that at that time was 94%-owned by us, paid dividends in the amount of $17,000 to its minority shareholders. In 2000 the subsidiary acquired and retired the stock of the two minority holders. As a result, the subsidiary is now wholly-owned by us, and there is no longer the issue of dividends being paid by a subsidiary to persons outside the consolidated group. No dividends have ever been paid on our common stock.

NOTE 6 -- SETTLEMENTS EXPENSE

On May 22, 2001, we settled litigation with Phillips Petroleum Company and acquired Phillips' Net Profits Interest in South Pass block 89, offshore Louisiana. We paid $21.25 million cash and issued 1,189,344 shares of our common stock as consideration for the settlement and assignment of the net profits interest.

Of the total $42.5 million settlement, we had previously recorded $20.2 million as an accrued liability. We recorded $12.3 million of the remaining $22.3 million as additional settlement expense and capitalized $10.0 million as the cost for our purchase of the net profits interest. In addition, we charged the remaining $1.2 million deferred net profits expense related to a royalty settlement in 2000 to the settlement expense.

We agreed to purchase up to 100,000 shares per week from Phillips at $17.867 per share in the event that Phillips was unable to sell the shares at or above that price. Subsequently, Phillips sold 33,900 shares on the open market, and we purchased the remaining 1,155,444 shares at a total cost of $20.6 million.

The Minerals Management Service is the grantor of all leases in the federal waters offshore Louisiana. When production is established, they collect a royalty from hydrocarbons produced from the lease. After a routine audit of our royalty payments, the Minerals Management Service issued orders to pay additional royalty on three separate claims regarding our South Pass 89 lease complex. We settled all three of those claims in 2000 for a total of $5.4 million.

NOTE 7 -- EMPLOYEE AND DIRECTOR BENEFIT PLANS

STOCK OPTION PLAN

The compensation committee of the Board of Directors, comprising three independent directors, administers the 1997 Stock Option Plan. This committee has the discretion to determine the participants, the number of shares granted to each person, the purchase price of the common stock covered by each option, and most other terms of the option. Options granted under the plan may be either incentive stock options or non-qualified stock options. The committee may issue options for up to 3.75 million shares of common stock, but no more than 937,500 shares to any individual. Forfeited options are available for future issuance. In accounting for stock options granted to employees and directors, we have chosen to continue to apply the accounting method promulgated by Accounting Principles Board Opinion No. 25 ("APB 25") rather than apply an alternative method permitted by Statement of Financial Accounting Standards No. 123 ("SFAS 123"). Under APB 25, at the time of grant we do not record compensation expense on our income statement for stock options granted to employees or directors.

A summary of our stock option plans as of December 31, 2002, 2001, and 2000, and changes during the years ending on those dates is presented below:

	AT DECEMBER 31,					
	2002		2001		2000	
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	W A E
Outstanding at beginning of year....	2,598,700	$ 6.72	2,581,503	$ 5.28	1,761,000	
Granted............................	400,000	$17.20	345,000	$15.33	979,000	
Exercised..........................	(440,978)	$ 4.87	(327,803)	$ 4.39	(33,497)	
Forfeited..........................	(5,503)	$ 9.04	--	$ --	(125,000)	
Outstanding at end of year..........	2,552,219	$ 8.68	2,598,700	$ 6.72	2,581,503	
Options exercisable at year-end.....	1,613,554	$ 6.54	1,441,384	$ 6.13	1,097,860	
Weighted-average fair value of options Granted during the year...		$12.64		$11.55		

The options outstanding at December 31, 2002, have a weighted-average remaining contractual life of 7.18 years and an exercise price ranging from $3.125 to $20.34 per share. A breakdown of the options outstanding at December 31, 2002 by price range is presented below:

OPTION PRICE RANGE	NUMBER	WEIGHTED AVERAGE EXERCISE PRICE	WEIGHTED AVERAGE REMAINING LIFE (YEARS)	NUMBER EXERCISABLE	WEIGHTED AVERAGE PRICE ON OPTIONS EXERCISABLE
$3.125 -- $4.25	1,016,901	$ 3.86	7.00	716,569	$ 3.90
$5.0625 -- $6.9375	499,818	$ 6.34	4.92	499,818	$ 6.34
$8.625 -- $9.00	145,000	$ 8.95	5.73	135,000	$ 8.97
$11.00 -- $15.32	460,500	$13.84	8.05	252,167	$12.72
$16.55 -- $20.34	430,000	$17.16	9.80	10,000	$16.67

The table below reflects the effect on our net income if we recorded the estimated compensation costs for the stock options using the estimated fair value as determined by applying the Black-Scholes option pricing model.

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
As reported:			
Net income	$11,332	$8,344	$45,044
Basic income per share	$ 0.45	$ 0.38	$ 2.10
Diluted income per share	$ 0.42	$ 0.35	$ 1.99
Stock based compensation (net of tax at statutory rate of 35%) included in net income as reported	$ 1,046	$2,402	$ 113
Stock based compensation (net of tax at statutory rate of 35%) if using the fair value method as applied to all awards	$ 2,531	$4,248	$ 1,178
Proforma (if using the fair value method applied to all awards):			
Net income	$ 9,847	$6,498	$43,866
Basic income per share	$ 0.39	$ 0.30	$ 2.05
Diluted income per share	$ 0.36	$ 0.27	$ 1.94
Weighted average shares used in computation Basic	25,294	21,979	21,435
Diluted	27,122	24,414	22,759

The fair value of each option grant for the years ended December 31, 2002, 2001, and 2000 is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
Expected life (years)	10	10	10
Interest rate	4.17%	5.13%	6.18%
Volatility	61.62%	62.56%	59.01%
Dividend yield	0%	0%	0%

NON-EMPLOYEE DIRECTOR STOCK PURCHASE PLAN

The non-employee director stock purchase plan allows the non-employee directors to receive their directors' fees in shares of restricted common stock instead of cash. The number of shares received will be equal to 150% of the cash fees divided by the closing market price of the common stock on the day that the

cash fees would otherwise be paid. The director cannot transfer the common stock until one year after issuance or the termination of a director resulting from death, disability, removal, or failure to be nominated for an additional term. The director can vote the shares of restricted stock and receive any dividend paid.

PENSION PLAN

Remington and CKB Petroleum, Inc. each have a noncontributory defined benefit pension plan. The retirement benefits available are generally based on years of service and average earnings. We fund the plans with annual contributions at least equal to the minimum funding provisions of the Employee Retirement Income

Security Act of 1974, as amended, but usually no more than the maximum tax deductible contribution allowed. Plan assets consist primarily of equity and fixed income securities. The following table sets forth the reconciliation of the benefit obligation, plan assets, and funded status for the pension plans.

	AT DECEMBER 31,	
	2002	2001
RECONCILIATION OF THE CHANGE IN BENEFIT OBLIGATION		
Beginning benefit obligation	$3,305	$3,103
Service cost	291	151
Interest cost	263	221
Actuarial loss	1,179	59
Benefits paid	(205)	(229)
Ending benefit obligation	$4,833	$3,305
RECONCILIATION OF THE CHANGE IN PLAN ASSETS		
Beginning market value	$2,766	$3,090
Actual return on plan assets	(324)	(282)
Employer contributions	2,269	187
Benefit payments	(205)	(229)
Ending market value	$4,506	$2,766
FUNDED STATUS AND AMOUNTS RECOGNIZED IN THE BALANCE SHEET		
Funded status	$ (327)	$ (539)
Unrecognized net actuarial loss	2,473	813

Adjusted prepaid benefit cost	$2,146	$ 274

The net periodic pension cost recognized in our income statements include the following components:

	FOR YEARS ENDED DECEMBER 31, 2002	2001	2000
	(IN THOUSANDS)		
COMPONENTS OF NET PERIODIC PENSION COST			
Service cost	$291	$151	$119
Interest cost on projected benefit obligation	263	221	226
Expected return on plan assets	(219)	(239)	(273)
Recognized net actuarial loss	62	--	--
Net amortization and deferrals	--	--	(2)
Net periodic pension cost	$397	$133	$ 70

	FOR YEARS ENDED DECEMBER 31, 2002	2001	2000
	(IN THOUSANDS)		
WEIGHTED AVERAGE ASSUMPTIONS			
Discount rate	6.50%	7.25%	7.50%
Expected return on plan assets	8.00%	8.00%	8.00%
Rate of compensation increase	3.00%	3.00%	3.00%

Remington's aggregate projected benefit obligation at December 31, 2002 was $4.2 million and the aggregate fair value of plan assets was $3.8 million. On December 31, 2002, Remington had a prepaid benefit cost of $1.8 million. CKB Petroleum's aggregate projected benefit obligation at December 31, 2002 was $613,000 and the aggregate fair value of plan assets was $673,000. On December 31, 2002, CKB Petroleum had a prepaid benefit cost of $344,000.

CONTINGENT STOCK GRANT

In June 1999, the Board of Directors approved a contingent stock grant to our employees and directors. In order for the grant to become effective, the price of our stock had to increase from $4.19 per share to a trigger price of $10.42 per share and close at or above $10.42 per share for 20 consecutive trading days within 5 years of the grant date.

On January 24, 2001, the stock price closed above the trigger price for the twentieth consecutive trading day. On that date, we measured the total compensation cost at $8.1 million which was the total number of shares granted multiplied by the market price on that date. We recorded $8.1 million as restricted common stock, $5.7 million as unearned compensation reported as a separate reduction in stockholders' equity on the balance sheet, and $2.4 million as stock based compensation expense. The $2.4 million stock based compensation expense recorded in the first quarter of 2001 included a "catch up" amortization from the date of the grant to the measurement date of the total compensation cost. During the last three quarters of 2001 we amortized an additional $1.0 million. During 2002 we amortized $1.4 million to stock based compensation expense. The remaining unearned compensation expense will be amortized over the next three years as the shares vest. The total compensation expense may decrease if an employee fails to vest because he is no longer employed for any reason other than death, disability, or normal retirement, or if a director no longer serves for any reason other than death.

EMPLOYEE SEVERANCE PLAN, POST RETIREMENT BENEFITS AND POST EMPLOYMENT BENEFITS

Our employee severance plan provides severance benefits ranging from 2 months to 18 months of the employee's base salary if the employee is terminated involuntarily. The plan incorporates the provisions and terms of any individual contract or agreement that an employee may have with the company. Certain of the executive officers have individual employment contracts with the company.

We have never paid postretirement benefits other than pensions and have not obligated ourselves to pay such benefits in the future. Future obligations for postemployment benefits are immaterial. Therefore, we have not recognized any liability for either.

NOTE 8 -- INCOME TAXES

The following table provides a summary of our income tax expense:

	FOR YEARS ENDED DECEMBER 31, (IN THOUSANDS)		
	2002	2001	2000
Current income tax expense (benefit)	$ --	$ (12)	$100
Deferred income tax expense	6,095	3,600	--
Total income tax expense	$6,095	$3,588	$100

Total income tax expense differs from the amount computed by applying the federal income tax rate to net income before income taxes as follows:

	FOR YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Federal income tax expense at statutory rate	$6,095	$4,175	$15,799
Net adjustment to valuation allowance	--	(575)	(15,799)
Other	--	(12)	100
Total income tax expense	$6,095	$3,588	$ 100

The following table reflects the significant components of our deferred tax asset.

	AT DECEMBER 31,	
	2002	2001
	(IN THOUSANDS)	
(Liability) from difference in book and tax basis of oil and gas properties	$(15,671)	$(14,777)
Asset from difference in book and tax basis of other assets	43	826
Asset from difference in book and tax basis of accrued liabilities	2,745	2,923
Federal income tax operating loss carry-forward	5,275	7,761
Federal capital loss carry-forwards	--	--
Alternative minimum tax credit carry-forward	416	416
Total deferred tax (liability)	$ (7,192)	(2,851)
Valuation allowance	--	--
Net deferred tax (liability)	$ (7,192)	$ (2,851)

The unused federal income tax operating loss carry-forward of $15.1 million will expire during the years 2007 through 2020 if not utilized sooner.

NOTE 9 -- OIL AND GAS RESERVES AND PRESENT VALUE DISCLOSURES (UNAUDITED)

The estimates of oil and gas reserves were prepared by the independent reserve engineering firm of Netherland, Sewell & Associates, Inc. The determination of these reserves is a complex and interpretative process that is subject to continued revision as additional information becomes available. In many cases, a relatively accurate determination of reserves may not be possible for several years due to the time necessary for development drilling, testing and studies of the reservoirs. We do not file reserve estimates with any other Federal authority or agency.

The quantities of proved oil and gas reserves presented below include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic and operating conditions. Proved reserves include only quantities that we can commercially recover using current prices, costs, existing regulatory practices and technology. Therefore, any changes in future prices, costs, regulations, technology or other unforeseen factors could significantly increase or decrease proved reserve estimates. Our proved undeveloped reserves are generally brought on line within 12 months. Alternatively, they are associated with long life fields where economics dictate waiting for an existing wellbore available for sidetrack, or waiting to mobilize a platform rig for operations. Accordingly, proved undeveloped reserves in major fields may be carried for many years. The following table presents our net ownership interest in proved oil and gas reserves.

	AT DECEMBER 31,					
	2002		2001		2000	
	OIL BBLS	GAS MCF	OIL BBLS	GAS MCF	OIL BBLS	GAS MCF
	(IN THOUSANDS)					
Beginning of period	13,865	111,920	10,370	88,650	7,177	65,508
Revisions of previous estimates	(596)	(4,271)	1,221	(1,414)	71	893
Extensions, discoveries and other	1,678	39,603	3,507	45,951	5,028	44,528
Reserves purchased	--	--	--	--	35	294
Reserves sold	(104)	(4,837)	--	--	(760)	(9,816)
Production	(1,729)	(17,448)	(1,233)	(21,267)	(1,181)	(12,757)
End of period	13,114	124,967	13,865	111,920	10,370	88,650
Proved developed reserves	7,977	71,481	6,690	60,756	5,345	71,995

The proved developed and undeveloped reserves and standardized measure of discounted future net cash flows associated with South Pass block 89 were burdened by a 33% net profits interest for the year ended December 31, 2000. In May 2001, we purchased the net profits interest from Phillips Petroleum. The reserves included in the above table for the two previous years include our full net ownership interest without any reduction for the net profits interest, because the agreement creating the net profits allowed only an interest in the net profit and not an ownership interest in the oil and gas reserves.

The following tables represent value-based information about our proved oil and gas reserves. The standardized measure of discounted future net cash flows result from the application of specific criteria applicable to the value-based disclosures of all oil and gas reserves in the industry. Due to the imprecise nature of estimating oil and gas reserve quantities and the uncertainty of future economic conditions, we cannot make any representation about interpretations that may be made or what degree of reliance that may be placed on this method of evaluating proved oil and gas reserves.

We compute future cash revenue by multiplying the year-end commodity prices or contractual pricing if applicable, by estimated future production from proved oil and gas reserves. We use year end West Texas Intermediate posted prices per barrel and Gulf Coast spot market prices or NYMEX Henry Hub futures price per MMBtu adjusted by property for energy content, quality, transportation fees, and regional price differentials.

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
West Texas Intermediate (per barrel)	$28.00	$16.75	$26.80
Gulf Coast Spot Market (per MMbtu)	$ 4.74	$ 2.65	--
NYMEX Henry Hub futures price (per MMbtu)	--	--	$ 9.78

We estimated the costs based on the prior year costs incurred for individual properties, or, similar properties if a particular property did not have production during the prior year. We calculated the future net profits expense by multiplying the net profit percentage by the future revenue less production and development costs on South Pass block 89. Future income tax expense was determined by applying the current tax rate to the estimated future net cash flow from all properties. Finally, we discounted the future net cash flow, after tax, by 10% per year to arrive at the standardized measure of discounted future net cash flows presented below.

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Oil and gas revenues	$946,813	$542,193	$1,111,238
Production costs	(150,084)	(107,586)	(96,847)
Development costs (1)	(116,944)	(84,561)	(75,995)
Net Profits expense	--	--	(15,059)
Income tax expense	(166,864)	(53,020)	(287,959)
Net cash flow	512,921	297,026	635,378
10% annual discount	(161,879)	(97,043)	(176,729)
Standardized measure of discounted future net cash flows	$351,042	$199,983	$ 458,649

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(1) Based on Netherland, Sewell & Associates' reserve report for January 1, 2003, we estimate that the amount of capital required to convert proved undeveloped reserves to proved developed reserves will be $88.2 million of the $116.9 million of future development costs, including $25.9 million in 2003, $14.5 million in 2004 and $10.4 million in 2005. Our actual expenditures may differ from these estimates. Capital expenditures incurred to develop proved undeveloped reserves were $28.5 million in 2002, $19.3 million in 2001 and $2.3 million in 2000.

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REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

The following table summarizes the principal sources of change in the standardized measure of discounted future net cash flows from year to year.

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Standardized measure of discounted cash flows at beginning of year	$199,983	$458,649	$126,868
Sales and transfers of oil and gas produced, net of production costs and net profits expense	(84,231)	(98,274)	(73,866)
Net changes in prices and production costs	198,760	(486,774)	268,139
Net changes in estimated development costs	(4,229)	70	4,500
Net changes in estimated net profits expense	--	10,510	(7,139)
Net changes in income tax expense	(79,090)	172,708	(175,031)
Extensions, discoveries and improved recovery less related costs	123,755	89,048	314,747
Proved oil and gas reserves purchased	--	--	2,888
Proved oil and gas reserves sold	(6,997)	--	(26,016)
Previously estimated development costs incurred during the year	22,893	32,687	8,776
Revisions of previous quantity estimates	(24,244)	13,356	8,274
Other changes	(15,556)	(37,861)	(6,178)
Accretion of discount	19,998	45,864	12,687
Standardized measure of discounted future net cash flows at end of year	$351,042	$199,983	$458,649

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REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 10 -- QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	FOR YEARS ENDING DECEMBER 31,	
	2002	2001
	(IN THOUSANDS, EXCEPT PER SHARE DATA)	
FIRST QUARTER		
Net revenues(1)	$19,375	$39,290
Net income	$ 258	$14,657

Basic net income per share	$ 0.01	$ 0.68
Diluted net income per share	$ 0.01	$ 0.60
SECOND QUARTER		
Net revenues(1)	$27,406	$33,380
Net income (2)	$ 6,252	$ 1,241
Basic net income per share	$ 0.24	$ 0.06
Diluted net income per share	$ 0.22	$ 0.05
THIRD QUARTER		
Net revenues(1)	$25,937	$22,664
Net income	$ 3,967	$ 383
Basic net income per share	$ 0.15	$ 0.02
Diluted net income per share	$ 0.14	$ 0.02
FOURTH QUARTER		
Net revenues(1)	$27,663	$18,887
Net income (loss)	$ 855	$(7,937)
Basic net income per share	$ 0.03	$ (0.35)
Diluted net income per share	$ 0.03	$ (0.35)

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(1) Net revenues include only oil and gas sales revenue.

(2) Net income during the second quarter of 2002 includes a $4.1 million gain on sale of certain South Texas properties.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

As recommended by Remington's Audit Committee, Remington's Board of Directors on April 17, 2002, dismissed Arthur Andersen LLP ("Andersen") as Remington's independent public accountants and engaged Ernst & Young LLP to serve as Remington's independent public accountants for 2002.

Andersen's reports on Remington's consolidated financial statements for the past two years did not contain an adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles.

During Remington's two most recent fiscal years and through April 17, 2002, there were no disagreements with Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure which, if not resolved to Andersen's satisfaction, would have caused them to make reference to the subject matter in connection with their report on Remington's consolidated financial statements for such years; and there were no reportable events, as listed in Item 304(a)(1)(v) of Regulation S-K.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The following information relates to the members of our board of directors or executive officers during 2002. Each director holds office until his successor is elected and qualified or until his resignation or removal. Executive officers hold their respective offices at the pleasure of the board of directors.

DON D. BOX Age 52

POSITIONS WITH US:

- Director since March 1991
- Executive Vice President since October 1997
- Chairman of the Board January 1994-October 1997
- Chief Executive Officer August 1996-October 1997
- President August 1996-March 1997

POSITIONS WITH OUR AFFILIATES:

- CKB Petroleum, Inc.
  - Vice President since September 1997
  - Director August 1982-September 1997
  - President August 1982-September 1997
- CKB & Associates, Inc.
  - Vice President since May 1981
  - Director May 1981-September 1997

OUTSIDE DIRECTORSHIPS

- Authoriszer, Inc.

EDUCATION

- Bachelor of Arts -- University of Pennsylvania
- Bachelor of Science in Economics -- The Wharton School of the University of Pennsylvania
- Masters of Business Administration -- Southern Methodist University

JOHN E. GOBLE, JR., CPA Age: 56

POSITIONS WITH US:

- Director since April 1997
- Member -- Audit Committee (Chairman)

EMPLOYMENT:

- Byrd Investments -- Investment and financial advisor since 1986

OUTSIDE DIRECTORSHIPS:

- Miracle of Pentecost Foundation

EDUCATION:

- Bachelor of Business Administration -- Southern Methodist University

WILLIAM E. GREENWOOD Age: 64

POSITIONS WITH US:

- Director since April 1997
- Member -- Audit Committee
- Member -- Compensation Committee

EMPLOYMENT:

- Consultant since 1995
- Director and Chief Operating Officer -- Burlington Northern Railroad Corporation from 1990 until 1994

OUTSIDE DIRECTORSHIPS:

- Transport Dynamics Inc. (Chairman)
- President -- Mendota Museum and Historical Society

EDUCATION:

- Bachelor of Science -- Marquette University

DAVID H. HAWK Age: 58

POSITIONS WITH US:

- Director since September 1997
- Chairman of the Board since October 1997
- Member -- Executive Committee

EMPLOYMENT:

- J.R. Simplot Company (a large producer of frozen potatoes, vegetables, fertilizer and cattle) -- Director, Energy Natural Resources since 1984
- Previously employed with Atlantic Richfield Company and Tenneco Inc. as an Exploration Geologist
- Prior executive positions with IGC Production Company, Sundance Oil Company and Horn Resources Corporation

EDUCATION:

- Bachelor of Science in Geology and Distinguished Graduate Medalist -- University of Idaho
- Master of Science in Geology -- University of Oklahoma

JAMES ARTHUR LYLE, CCIM Age: 58

CURRENT POSITIONS WITH US:

- Director since September 1997
- Member -- Compensation Committee

EMPLOYMENT:

- Owner -- James Arthur Lyle & Associates, Inc., a commercial, industrial and investment real estate firm, since 1976

OUTSIDE DIRECTORSHIPS:

- Director, Chief Operating Officer and President since 1984 - Hueco Mountain Estates, Inc., a 10,500 acre multi-use real estate development located in El Paso County, Texas

EDUCATION:

- Bachelor of Science in Industrial Management -- Georgia Institute of Technology

DAVID E. PRENG Age: 56

POSITION WITH US:

- Director since April 1997
- Chairman -- Compensation Committee

EMPLOYMENT:

- Chief Executive Officer and President since 1980 -- Preng and Associates, an international executive search firm specializing in the energy industry

OUTSIDE DIRECTORSHIPS:

- Director -- Community National Bank
- Fellow -- Institute of Directors

EDUCATION:

- Bachelor of Science in Business Administration -- Marquette University
- Master of Business Administration -- DePaul University

THOMAS W. ROLLINS Age: 72

POSITIONS WITH US:

- Director since July 1996
- Member -- Executive Committee

EMPLOYMENT:

- Chief Executive Officer since 1985 -- Rollins Resources, a natural gas and oil consulting firm

- Previously held executive positions and/or directorships with Shell Oil Company, Pennzoil Company, Florida Gas Transmission Company, Pogo Producing Company, Magma Copper Company and Felmont Oil Corporation.

OUTSIDE DIRECTORSHIPS:

- Director -- Pheasant Ridge Winery

- Director -- The Teaching Company

- Director -- Nature Conservancy of Texas

EDUCATION:

- Geological Engineering Degree and Distinguished Graduate Medalist -- The Colorado School of Mines

ALAN C. SHAPIRO Age: 57

POSITIONS WITH US:

- Director since May 1994

- Audit Committee

EMPLOYMENT:

- The Ivadelle and Theodore Johnson Professor of Banking and Finance in the Department of Finance and Business Economics, Marshall School of Business, University of Southern California, since 1992

- Chairman of the Department of Finance and Business Economics, University of Southern California, 1993-1998

- Frequent consultant and expert witness to business and government

PUBLICATIONS:

- Multinational Financial Management, a best selling textbook used in MBA programs worldwide

- Numerous other books and articles

EDUCATION:

- Bachelor of Arts in Mathematics -- Rice University

- Ph.D. in Economics -- Carnegie Mellon University

JAMES A. WATT Age: 53

POSITIONS WITH US:

- Chief Executive Officer since February 1998

- President since March 1997
- Director since September 1997
- Member -- Executive Committee

POSITIONS WITH OUR AFFILIATES:

- CKB Petroleum, Inc.
  - Director and President since January 1999
- CKB & Associates, Inc.
  - Director and President since January 1999

PREVIOUS EMPLOYMENT HIGHLIGHTS:

- Vice President/Exploration -- Seagull E&P, Inc., 1993-1997
- Vice President/Exploration and Exploitation -- Nerco Oil & Gas, Inc., 1991-1993

OUTSIDE DIRECTORSHIPS:

- Director -- Suzuki Institute of Dallas

EDUCATION:

- Bachelor of Science in Physics -- Rensselaer Polytechnic Institute

ROBERT P. MURPHY Age: 44

POSITIONS WITH US:

- Chief Operating Officer since October 2000 and Senior Vice President/Exploration & Production since July 1999
- Vice President/Exploration, January 1998-June 1999

PREVIOUS EMPLOYMENT:

- Director -- Cairn Energy USA, Inc., May 1996-November 1997
- Vice President -- Exploration -- Cairn Energy USA, March 1993-January 1998
- Exploration Geologist -- Cairn Energy USA, 1990-March 1993

- Exploration Geologist -- Enserch Exploration, 1984-1990

EDUCATION:

- Bachelor of Science in Geology -- The University of Texas at Austin
- Master of Science in Geosciences -- The University of Texas at Dallas

STEVEN J. CRAIG Age: 51

POSITIONS WITH US:

- Senior Vice President/Planning and Administration since April 1997

POSITIONS WITH OUR AFFILIATES:

- CKB Petroleum, Inc.
  - Director and Vice President since January 1999
  - Vice President and Assistant Treasurer, March 1997-October 1997
  - Director, March 1997-August 1997
- CKB & Associates, Inc.
  - Director and Vice President since January 1999
  - Vice President and Assistant Treasurer, March 1997-October 1997
  - Director, March 1997-August 1997
- S-Sixteen Holding Company
  - Vice President and Assistant Treasurer, March 1997-October 1997
  - Director, March 1997-August 1997

EDUCATION:

- Bachelor of Arts in Economics -- Southern Methodist University
- Master of Business Administration in Finance and Quantitative Analysis -- Southern Methodist University

J. BURKE ASHER Age: 62

POSITIONS WITH US:

- Vice President/Finance since December 1997
- Secretary since October 1996
- Chief Accounting Officer, September 1996-December 1997

POSITIONS WITH OUR AFFILIATES:

- CKB Petroleum, Inc.
  - Treasurer and Assistant Secretary since March 1997
  - Director, March 1997-April 1997
- CKB & Associates, Inc.
  - Treasurer and Assistant Secretary since March 1997
  - Director, March 1997-August 1997

- S-Sixteen Holding Company
  - Treasurer and Assistant Secretary, March 1997-December 1998
  - Director, March 1997-August 1997

EDUCATION:

- Bachelor of Science in Economics -- The Wharton School of the University of Pennsylvania

GREGORY B. COX Age: 49

POSITIONS WITH US:

- Vice President/Exploration since January 2002
- Exploration Manager since October 1997

EDUCATION:

- Bachelor of Science in Geology -- University of Texas at Arlington

EDWARD V. HOWARD, CPA Age: 39

POSITIONS WITH US:

- Vice President/Controller since March 1992
- Assistant Secretary since October 1997

EDUCATION:

- Bachelor of Business Administration -- West Texas State University

Except for Mr. Rollins' consulting practice, no director has a significant personal interest in the exploration, development or production of oil and gas. Mr. Rollins is required to abstain on matters in which there may be a conflict of interest between us and one of his clients.

LITIGATION INVOLVING DIRECTORS AND EXECUTIVE OFFICERS

We know of no reportable litigation involving the directors or executive officers.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Based solely upon our review of Forms 3, 4, and 5 received by us for 2002, all persons required by Section 16(a) of the Securities Exchange Act of 1934 ("the Act") to file such forms complied with Section 16(a) of the Act.

ITEM 11. EXECUTIVE COMPENSATION.

The following table summarizes the compensation paid by the company during 2002, 2001, and 2000 to the company's Chief Executive Officer and its four most highly compensated executive officers, other than the Chief Executive Officer, whose total annual salary and bonus in 2002 exceeded $100,000.

SUMMARY COMPENSATION TABLE

		ANNUAL COMPENSATION				LONG-TERM C
NAME AND PRINCIPAL POSITION	FISCAL YEAR	SALARY ($)	BONUS ($)	OTHER ANNUAL COMPENSATION ($)(1)	RESTRICTED STOCK AWARDS (#)	SECURI UNDERL OPTIO SAR' (#)
James A. Watt.................. Chief Executive Officer and President	2002	360,000	252,000	--	(2)	35,0
	2001	320,004	405,000	--	62,089(3)	35,0
	2000	282,501	296,000	--	--.......	123,0
Robert P. Murphy................ Chief Operating Officer and Senior Vice President/ Exploration and Production	2002	275,004	159,000	--	--.......	32,0
	2001	225,000	200,000	--	41,791(3)	25,0
	2000	187,506	140,000	--	--.......	66,0
Gregory B. Cox.................. Vice President/ Exploration	2002	167,004	57,000	--	--.......	20,0
	2001	147,000	45,000	--	30,089(3)	15,0
	2000	132,300	43,000	--	--.......	45,0
Steven J. Craig................. Senior Vice President/ Planning and Administration	2002	165,000	41,000	--	--.......	18,0
	2001	125,808	46,000	--	27,391(3)	12,0
	2000	121,008	29,000	--	--.......	39,0
J. Burke Asher.................. Vice President/Finance and Secretary	2002	150,000	37,000	--	--.......	17,5
	2001	119,600	44,000	--	26,077(3)	11,5
	2000	115,008	27,600	--	--.......	37,0

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(1) No amount is included, as it is less than 10% of the total salary and bonus of the individual for the year.

(2) Effective March 17, 1997, in connection with his initial employment agreement, Mr. Watt was awarded 15,000 restricted shares of common stock, which vested and became unrestricted 20% per year from the effective date.

(3) On January 24, 2001, contingent grants of the number of shares of common stock shown became effective. For Mr. Cox, the shares vest 50% on June 17, 2002, and 25% each on June 17, 2003 and 2004. For the other officers, the shares vest 20% annually beginning January 17, 2002. Except in the event of death, long-term disability, or change of control, the officers will forfeit unvested shares if their employment with us terminates prior to the vesting dates.

(4) These amounts are for group term life insurance premiums paid by the company.

See "Change in Control Arrangements and Employment Contracts" below.

LONG TERM STOCK BASED INCENTIVE PROGRAMS

Stock Options

We have stock option plans for our employees and directors because we believe these options act as both an incentive and a reward for the long-term growth of our company. The core of our stock option program is

the 1997 stock option plan. Both directors and employees are eligible for options under this plan. Significant attributes of the 1997 plan include the following:

- Approved by the stockholders.

- Administered by the Compensation Committee of our board of directors.

- Subject to adjustments, up to 3,750,000 shares of our common stock may be issued under the plan.

- Up to 25% of issuable shares may be issued to any single individual.

- Both qualified incentive and non-qualified options may be issued.

- The plan terminates December 4, 2007.

The importance of whether an option is granted as a qualified incentive option or a non-qualified option is mainly tax driven. If an option is an incentive option, the exercise price can be no less than the fair market value on the date of grant. Additional details concerning the 1997 stock option plan are contained in the plan itself. For a copy of the plan, call Investor Relations at (214) 210-2650.

OPTION GRANTS IN LAST FISCAL YEAR

	INDIVIDUAL GRANTS				
NAME	NUMBER OF SECURITIES UNDERLYING OPTIONS GRANTED	PERCENT OF TOTAL OPTIONS GRANTED TO EMPLOYEES IN FISCAL YEAR	EXERCISE PRICE $/SHARE	EXPIRATION DATE	GRANT DATE PRESENT VALUE $(1)
James A. Watt..................	35,000	11%	17.15	12/17/12	440,640
Robert P. Murphy...............	32,000	10%	17.15	12/17/12	402,870
Gregory B. Cox.................	20,000	6%	17.15	12/17/12	251,794
Steven J. Craig................	18,000	6%	17.15	12/17/12	226,615
J. Burke Asher.................	17,500	5%	17.15	12/17/12	220,320

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(1) We determined these values using the Black-Scholes option pricing model with the following assumptions: stock price volatility of 61.61%; interest rate based on the yield to maturity of a 10-year Treasury security; exercise in the tenth year; and a dividend rate of zero. We made no adjustments for nontransferability or risk of forfeiture. Our use of this model does not constitute an endorsement or an acknowledgment that such model can accurately determine the value of options. No assurance can be given that the actual value, if any, realized by an executive upon the exercise of these options will approximate the estimated values calculated by using the Black-Scholes model.

AGGREGATED OPTION EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION VALUES

NAME	NUMBER OF SHARES ACQUIRED ON EXERCISE	VALUE REALIZED ($)(1)	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS AT FISCAL YEAR-END		VALUE OF UNEX IN-THE-MONEY O FISCAL YEAR-EN	
			EXERCISABLE	UNEXERCISABLE	EXERCISABLE	UN
James A. Watt...........	49,099	603,580	308,197	99,333	3,633,763	
Robert P. Murphy........	33,588	495,251	137,742	70,666	1,514,724	
Gregory B. Cox..........	--	--	73,666	45,000	809,762	
Steven J. Craig.........	56,402	563,653	23,597	21,000	248,450	
J. Burke Asher..........	32,151	494,442	54,499	37,500	550,277	

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(1) Computed as the number of securities multiplied by the difference between the option exercise price and the mean of the high and low price of our common stock on the date of exercise.

(2) Computed as the number of securities multiplied by the difference between the option exercise prices and the closing price of our common stock on December 31, 2002.

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CONTINGENT STOCK GRANTS

In 1999, the directors approved contingent awards of stock to employees and directors totaling 679,937 shares of our common stock. The number of shares awarded to each employee and director was based on the employee's annual base salary as of June 17,1999, or in the case of non employee directors, $100,000, divided by $4.19, which was the closing stock price on June 17, 1999. In order for the grant to be effective, our stock had to close above a trigger price of $10.42 for 20 consecutive trading days within 5 years of the grant date. This trigger was achieved on January 24, 2001. Recipients of the grant must remain an employee or a director during the vesting schedules in order to receive the shares. Employees and directors individually elected one of two vesting periods. The first vesting schedule has 50% percent of the grant vesting on June 17, 2002, with an additional 25% vesting on June 17, 2003, and the final 25% vesting on June 17, 2004. 264,863 shares are subject to this vesting schedule. The second vesting option has 20% of the grant vesting on January 17, 2002, with an additional 20% vesting on each successive January 17 through 2006. 395,090 shares are subject to the second vesting schedule. While 679,937 shares of restricted stock were granted in 1999, as of March 27, 2003, 659,953 shares are subject to the grant because a director voluntarily surrendered 23,880 shares, a new employee was granted 6,535 shares, and an employee terminated, forfeiting 2,639 shares. The number of shares subject to the grant may decrease to the degree that participants fail to remain with us during the vesting period. In the event of a participant's death while employed or serving as a director with us, or reaching the retirement age of 65 or receiving long term disability benefits while employed with us, a grant becomes 100% vested. In addition, the grants can become 100% vested upon a change of control.

PENSION PLANS

Our defined benefit pension plans provide retirement and other benefits to eligible employees upon reaching the "normal retirement age," which is age 65 or after 3 years of service (5 years if employment terminated prior to January 1, 2001), if later. Directors who are not also employees of the company are not eligible to participate in the plans. Employees are eligible to participate on January 1 following the completion of six months of service or the attainment of age 20 1/2, if later. Additional provisions are made for early or late retirement, disability retirement and benefits to surviving spouses. At normal retirement age, an eligible employee will receive a monthly retirement income equal to 35% of his or her average monthly compensation during the three consecutive calendar years in the prior 10 years which provide the highest average compensation, plus 0.65% of such average compensation in excess of the amount shown in the Social Security Covered Compensation Table (as published annually by the Internal Revenue Service) multiplied by his or her years of service, limited to 35 years. If an employee terminates employment (other than by death or disability) before completion of three years of service (five years if employment terminated prior to January 1, 2001), no benefits are payable. If an employee terminates employment after three years of service (five years if employment terminated prior to January 1, 2001), the employee is entitled to all accrued benefits. The following table illustrates the annual pension for plan participants that retire at "normal retirement age" in 2002:

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PENSION PLAN TABLE

	YEARS OF SERVICE (1)(3)(4)				
AVERAGE COMPENSATION(1)(2)	15	20	25	30	35
($)	($)	($)	($)	($)	($)
125,000	52,135	54,930	57,725	60,520	63,315
150,000	63,323	66,930	70,538	74,145	77,753
175,000	74,510	78,930	83,350	87,770	92,190
200,000	85,698	90,930	96,163	101,395	106,628
225,000	85,698	90,930	96,163	101,395	106,628
250,000	85,698	90,930	96,163	101,395	106,628
300,000	85,698	90,930	96,163	101,395	106,628
400,000	85,698	90,930	96,163	101,395	106,628
450,000	85,698	90,930	96,163	101,395	106,628
500,000	85,698	90,930	96,163	101,395	106,628

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(1) As of December 31, 2002, the Internal Revenue Code does not allow qualified plan compensation to exceed $200,000 or the benefit payable annually to exceed $160,000. The Internal Revenue Service will adjust these limitations for inflation in future years. When the limitations are raised, the compensation considered and the benefits payable under the pension plans will increase to the level of the new limitations or the amount otherwise payable under the pension plans, whichever amount is lower.

(2) Subject to the above limitations, compensation in this table is generally equal to all of a participant's cash compensation paid in a fiscal year (the total of Salary, Bonus, and Other Annual Compensation in the Summary Compensation Table). Average compensation in this table is the average of a

plan participant's compensation during the highest three consecutive years out of the prior 10 years.

(3) The estimated credited service at December 31, 2002, for the executive officers shown in the Summary Compensation Table on page 49 is as follows: James A. Watt (6 years), Robert P. Murphy (5 years), Steven J. Craig (8 years), J. Burke Asher (6 years), and Gregory B. Cox (5 years).

(4) The normal form of payment is a life annuity for a single participant or a 50% joint and survivor annuity for a married participant. Such benefits are not subject to a deduction for Social Security or other offset amounts.

Compensation of Directors

- Only non-employee directors are compensated for board service
- Compensation includes:
  - Annual retainer of $20,000
  - $1,000 per board meeting attended (Chairman of the Board receives extra $250 per board meeting attended)
  - Unless surrendered, eligible for stock grant (see discussion of grant beginning on page 53)
  - Committee meeting fee of $750 per meeting attended by committee members or $1,000 for the committee chairman per meeting attended, if on a different day than a full board meeting
  - Directors are entitled to reimbursement of company related out-of-pocket expenses
  - We provide directors and officers insurance and indemnification to the full extent allowed by law
  - All or part of a director's board compensation may be received in company stock in accordance with the Non-Employee Director Stock Purchase Plan
- There were 5 board meetings in 2002

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- All directors attended at least 75% of the meetings
- During 2001, we paid an entity controlled by director David E. Preng $2,000 for consulting fees.
- In 2002, non-employee directors were awarded non-qualified stock options with exercise prices of $17.15, exercisable 1/3 per year beginning one year after the date of grant, as follows:
  - David H. Hawk - 10,000 shares
  - John E. Goble, David E. Preng, and Alan C. Shapiro - 7,500 shares each
  - William E. Greenwood, Thomas W. Rollins, and James Arthur Lyle - 5,000 shares

each

Non-Employee Director Stock Purchase Plan

- This plan was approved by the stockholders December 4, 1997
- Each non-employee director may, once a year, elect to receive all or part of his board compensation in our common stock
- The number of shares received equals 150% of the cash amount of compensation divided by the closing market price of our common stock on the day the cash fees would be payable
- Shares received under this plan may not be transferred for one year after issuance
- Shares may be transferred earlier than one year based on a director's death, disability or departure from the board
- During the restricted transfer period the director may vote the stock and receive any dividends
- The board may terminate this plan at any time
- Shares received under plan for 2002:

- John E. Goble, Jr.	1,041 shares in lieu of $12,000 cash
- William E. Greenwood	2,560 shares in lieu of $29,500 cash
- James Arthur Lyle	2,243 shares in lieu of $25,750 cash
- David E. Preng	2,266 shares in lieu of $26,000 cash
- Thomas W. Rollins	692 shares in lieu of $8,000 cash
- Alan C. Shapiro	2,560 shares in lieu of $29,500 cash

Change in Control Arrangements and Employment Contracts

All of our full-time regular employees are covered by a severance plan that we adopted in 1997. Under this plan, if an employee is involuntarily terminated, as that term is defined in the plan, the employee will be entitled to a payment of between two months base pay and eighteen months base pay depending on the employee's job and years of experience. If an employee voluntarily quits, is terminated for cause as defined in the plan, dies, leaves due to a disability for which benefits are payable, or the termination is expected to be of short duration, the employee is not eligible for payment under the plan. In addition, under certain circumstances, a change in control could cause immediate vesting and triggering of stock options and contingent stock grants. As of December 31, 2002, if the contingent stock grants were vested by a change in control, it would result in the issuance of a maximum aggregate of 447,192 shares to directors and employees.

Employment Agreements

We have employment agreements with James A. Watt, Robert P. Murphy, Gregory B. Cox, Steven J. Craig, and J. Burke Asher. The most significant terms of such agreements are summarized below:

James A. Watt

- Term of three years from January 31, 2000, subject to single year extensions by mutual agreement

- Base salary of $270,000 a year, subject to discretionary increases

- Eligible to receive discretionary performance bonus (targeted at 70% of base salary)

- If terminated prior to a change in control, without cause, he receives his salary plus a pro rata bonus

- He receives 2.99 times the sum of his base salary plus his target bonus if he is terminated within 24 months of a change in control, other than for death, disability or cause, or he leaves for good reason within the 24 month period

Robert P. Murphy

- Term of three years from September 30, 1999, subject to single year extensions by mutual agreement

- Base salary of $175,000 a year, subject to discretionary increases

- Eligible to receive discretionary performance bonus (targeted at 50% of base salary)

- If terminated prior to a change in control, without cause, he receives his salary plus a pro rata bonus

- He receives 2.99 times the sum of his base salary plus his target bonus if he is terminated within twelve months of a change in control, other than for death, disability or cause, or he leaves for good reason within the twelve month period

Gregory B. Cox

- Term of two years from April 30, 2002, subject to one year extensions by mutual agreement

- Base salary of $167,000, subject to discretionary increases

- Eligible to receive discretionary performance bonus (targeted at 35% of base salary)

- If terminated prior to a change in control, without cause, he receives all accrued compensation and a pro rata bonus plus a severance payment in lieu of further compensation equal to 1 times his current base salary

- He receives accrued compensation and a pro rata bonus and 2 times the sum of his base salary plus target bonus if he is terminated within twelve months of a change in control, other than for death, disability or cause, or he leaves for good reason within the twelve month period

Steven J. Craig and J. Burke Asher

- Term of two years from September 30, 1999, subject to single year extensions by mutual agreement

- Base salary of $114,200 (Mr. Craig) and $109,200 (Mr. Asher), subject to discretionary increases

- Eligible to receive discretionary performance bonus (targeted at 20% of base salary)

- Severance payments similar to Robert Murphy's, except that Mr. Craig and Mr. Asher each receive 2 times the sum of his annual salary plus target bonus in connection with leaving employment within twelve months of a change in control

Compensation Committee Interlocks and Insider Participation in Compensation Decisions

David E. Preng, William E. Greenwood, and James Arthur Lyle served on the compensation committee in 2002. No executive officer or employee serves on the compensation committee of the board. None of our executive officers serves on the board of directors of any other entity that has an executive officer serving on our board.

BOARD COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

We believe that employing and retaining highly qualified and high performing executive officers is vital to our achievement of long-term business goals. To this end, the Compensation Committee of the board of directors (the "Committee") developed an executive compensation program which is designed to attract and retain such officers.

The philosophy is to develop a systematic, competitive executive compensation program which recognizes an executive officer's position and responsibilities, takes into account competitive compensation levels payable within the industry by similarly sized companies, and reflects both individual and company performance.

The executive compensation program developed by the Committee is composed of the following three elements: (i) a base salary, (ii) a performance-based annual cash incentive (short-term), and (iii) a stock-based incentive (long-term). Under this program, short-term and long-term incentives are "at risk" and are based on performance of the company versus defined goals.

The Committee compiles data reflecting the compensation practices of a broad range of organizations in the oil and gas industry that are similar to us in size and performance. For both the base salary and annual cash incentives portions of executive compensation discussed below, the Committee adopted a philosophy of paying the executive officers at a level that is competitive and within the ranges reflected by the data compiled.

Base salaries

Base salary is the portion of an executive officer's total compensation package which is payable for performing the specific duties and assuming the specific responsibilities defining the executive's position with the company. The Committee's objective is to provide each executive officer a base salary that is competitive at the desired level.

Annual cash incentives

The Committee developed a performance-based annual cash incentive plan covering the executive officers and top managers. The objectives in designing the plan are to reward participants for accomplishing objectives which are generally measurable and increase shareholder value. Under the annual cash incentive plan, the Committee has established a "target" cash incentive award for each executive officer (including the Chief Executive Officer) that is payable based mostly upon the company's achieving certain performance targets and, to a lesser extent, for achieving highly challenging individual performance objectives. The performance targets are increasing reserves and production; controlling finding, development, production, and general and administrative costs; and achieving an acceptable overall return on capital; all of which are competitive with a peer group of oil and gas companies. The Committee also determined that award levels under the plan should be fiscally prudent.

Long-term stock-based incentives

We maintain a stock option plan for officers and other employees. The philosophy is to award stock options to selected plan participants based on their levels within the company and upon individual merit. The plan is to grant stock options which are competitive within the industry for other individuals at the employee's level and which provide the employee a meaningful incentive to remain with the company, to increase performance, and to focus on achieving long-term increases in shareholder value. Other factors the Committee considers in granting stock options include the employee's contributions toward achieving the company's long-term objectives, such as reserve and production growth, as well as the employee's contributions in achieving the company's short-term and long-term profitability targets.

COMPENSATION COMMITTEE

David E. Preng
William E. Greenwood
James Arthur Lyle

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PERFORMANCE GRAPH

The following performance graph compares the performance of all classes of our common stock to the Nasdaq indices of United States companies and to a peer group comprising Nasdaq companies listed under the Standard Industrial Classification Codes 1310-1319 for the company's last five fiscal years. Such industrial codes include companies engaged in the oil and gas business. The graph assumes that the value of an investment in our common stock and in each index was $100 at December 31, 1997, and that all dividends were reinvested.

PEFORMANCE GRAPH

	12/31/1997	12/31/1998	12/31/1999	12/31/2000	12/
REMA(1)........................	100.00	69.88	84.99	284.76	37
REMB(1)........................	100.00	61.46	74.76	250.48	33
NASDAQ U.S.	100.00	141.00	261.50	157.40	12
NASDAQ O&G.....................	100.00	48.60	50.20	104.30	7

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(1) The last day of trading for REMA and REMB was December 24, 1998. Effective at the opening of trading on December 28, 1998, both former classes of stock were replaced by a new single class of voting common stock (REM). The values shown above as of December 31, 1998, 1999, 2000, 2001 and 2002 for REMA give effect to the 1.15:1 exchange ratio that the former holders of REMA received in the exchange for the new class of common stock, and the 1:1 exchange ratio that the former holders of REMB received in the exchange for the new class of common stock.

Until December 24, 1998, our 2 classes of common stock were traded on the Nasdaq Stock Exchange under the symbols ROILA and ROILB. From December 28, 1998, through June 19, 2002, our single class of common stock traded on the Nasdaq Stock Exchange under the symbol ROIL. Since June 20, 2002, our common stock has traded on the New York Stock Exchange under the symbol REM. The designation REMA and REMB are used in the table above only to distinguish between the two classes of common stock that were outstanding on December 31, 1997.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Ownership of Certain Beneficial Owners

As of March 27, 2003, the following persons held shares of the company's common stock in amounts totaling more than 5% of the total shares of common stock outstanding. This information was furnished to us by such persons or statements filed with the Commission.

NAME AND ADDRESS OF BENEFICIAL OWNER	SHARES OF COMMON STOCK BENEFICIALLY OWNED	PERCENT OF COMMON STOCK
J.R. Simplot.. 999 Main Street Boise, Idaho 83702(1)	5,477,928(1)	20.8%

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(1) 2,785,028 shares are directly owned by JRS Properties III L.P. ("JRS Properties III"). The J.R. Simplot Self Declaration of Revocable Trust (the "Trust"), of which Mr. Simplot is the beneficiary and trustee, controls JRS Properties III. The Trust and a trust for the benefit of Mr. Simplot's spouse ("Mrs. Simplot's Trust"), which exercises no investment control, holds approximately 79.6% of the beneficial interest in the shares owned by JRS Properties III. 2,692,900 shares are directly owned by JRS Properties L.P. ("JRS Properties"). The Trust controls JRS Properties. The Trust and Mrs. Simplot's Trust hold approximately 98.7% of the beneficial interest in the shares owned by JRS Properties.

Ownership of Management

The number of shares of the company's common stock beneficially owned as of March 27, 2003, by directors of the company, each officer listed in the compensation table on page 49, and as a group comprising all directors and executive officers, are set forth in the following table. This information was furnished to the company by such persons.

NAME	SHARES OF COMMON STOCK BENEFICIALLY OWNED	OPTIONS EXERCISABLE WITHIN 60 DAYS OF MARCH 27, 2003	TOTAL	PERCENT OF COMMON STOCK
J. Burke Asher........................	18,397	66,833	85,230	*
Don D. Box............................	73,947	191,667	265,614	1.0%
Gregory B. Cox........................	48,546	40,120	88,666	*
Steven J. Craig.......................	92,282	28,264	120,546	*
John E. Goble, Jr.....................	23,666	90,001	113,667	*
William E. Greenwood..................	22,619	116,667	139,286	*
David H. Hawk.........................	2,430	--	2,430	*
James Arthur Lyle.....................	36,787	116,667	153,454	*
Robert P. Murphy......................	34,719	156,742	191,461	*
David E. Preng........................	56,766	126,667	183,433	*
Thomas W. Rollins.....................	20,979	91,667	112,646	*
Alan C. Shapiro.......................	47,621	116,667	164,288	*
James A. Watt.........................	108,988	349,197	458,185	1.7%
All directors and executive officers as a group (14 persons)............	615,493	1,512,991	2,128,484	7.6%

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* Less than one percent of the outstanding shares.

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The following table presents information about our equity compensation plans at December 31, 2002:

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	NUM SEC REM AVA FOR IS
	(A)	(B)	
Equity compensation plans approved by stockholders................................	2,552,219	$8.68	5
Equity compensation plans not approved by stockholders................................	447,192	$0.00	
Total..	2,999,411	$7.39	5

========= ===== ==

The information above regarding equity compensation plans not approved by the stockholders includes contingent one-time stock grants made in 1999 to all employees and directors, which include the following significant attributes:

- Shares awarded based on annual base salary as of June 17, 1999, or in the case of non-employee directors $100,000, divided by $4.19 (the closing price on June 17, 1999).

- In order for the grants to become effective, our common stock had to close at or above $10.42 per share for 20 consecutive trading days within 5 years of the grant date (the "trigger event").

- The trigger event was achieved on January 24, 2001.

- 686,472 shares were awarded. As of December 31, 2002, 212,761 shares have vested, and 26,519 shares have been forfeited. Of the remaining 447,192 shares, 131,117 shares vest 50% on June 17, 2003, and 50% on June 17, 2004; and 316,075 shares vest 25% on each successive January 17 beginning January 17, 2003.

- Each employee and director must remain an employee or director during his/her respective vesting schedule in order to receive the shares.

- In the event of death, long-term disability, change of control, or reaching the retirement age of 65, the shares will fully vest.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

A resolution adopted in 1992 by our board of directors authorizes us to enter into a transaction with an affiliate of ours so long as the board of directors determines that such a transaction is fair and reasonable to us and is on terms no less favorable to us than can be obtained from an unaffiliated party in an arms' length transaction.

We acquired a long-term receivable under a Collateral Assignment Split Dollar Insurance Agreement between CKB Petroleum, Inc. and Don D. Box in a merger in 1998. The amount due CKB Petroleum from Don D. Box under the Collateral Assignment Split Dollar Insurance Agreement was $140,000 on December 31, 2002, and $135,000 on December 31, 2001.

ITEM 14. CONTROLS AND PROCEDURES.

As of the end of the period covered by this report, our management, including our Chief Executive Officer and our Principal Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as defined in Exchange Act Rule 13a-15(e). Based on that evaluation, our management, including the Chief Executive Officer and the Principal Financial Officer, concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report. Further, during the period covered by this report, there was no significant change in internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

(a) Documents filed as part of this report:

1. Financial Statements included in Item 8:

   (i) Independent Auditors' Report

   (ii) Consolidated Balance Sheets as of December 31, 2002 and 2001

   (iii) Consolidated Statements of Income for years ended December 31, 2002, 2001 and 2000

   (iv) Consolidated Statement of Stockholders' Equity for years ended December 31, 2002, 2001 and 2000

   (v) Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000

   (vi) Notes to Consolidated Financial Statements

   (vii) Supplemental Oil and Natural Gas Information (Unaudited) (Included in the Notes to Consolidated Financial Statements)

2. Financial Statement Schedules

Financial statement schedules are omitted as they are not applicable, or the required information is included in the financial statements or notes thereto.

(b) Reports on Form 8-K:

We filed no reports on Form 8-K during the three months ended December 31, 2002.

(c) Exhibits:

3.1#	Certificate of Amendment of Certificate of Incorporation of Remington Oil and Gas Corporation.
3.3###	By-Laws as amended.
10.1***	Pension Plan of Remington Oil and Gas as Amended and Restated Effective January 1, 2000.
10.2***	Amendment Number One to the Pension Plan of Remington Oil and Gas Corporation.
10.3###	Amendment Number Two to the Pension Plan of Remington Oil and Gas Corporation.
10.4###	Amendment Number Three to the Pension Plan of Remington Oil and Gas Corporation.
10.6*	Box Energy Corporation Severance Plan.
10.7++	Box Energy Corporation 1997 Stock Option Plan. (as amended June 17, 1999 and May 23, 2001)
10.8*	Box Energy Corporation Non-Employee Director Stock Purchase Plan
10.9+	Form of Employment Agreement effective September 30, 1999, by and between Remington Oil and Gas Corporation and two executive officers.

10.10+	Form of Employment Agreement effective September 30, 1999, by and between Remington Oil and Gas Corporation and an executive officer.
10.11**	Employment Agreement effective January 31, 2000, by and between Remington Oil and Gas Corporation and James A. Watt.
10.12###	Form of Employment Agreement effective April 30, 2002, by and between Remington Oil and Gas Corporation and an executive officer.
21###	Subsidiaries of the registrant.
23.1+++	Consent of Ernst & Young LLP.
23.2+++	Notice Regarding Consent of Arthur Andersen LLP.
23.3+++	Consent of Netherland, Sewell & Associates.
31.1+++	Certification of James A. Watt, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2+++	Certification of J. Burke Asher, Principal Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+++	Certification of James A. Watt, Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+++	Certification of J. Burke Asher, Principal Financial Officer, pursuant to 18 U.S.C. Section 1350, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99***	Letter from Remington Oil and Gas Corporation to Securities and Exchange Commission regarding Arthur Andersen LLP representations.

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* Incorporated by reference to the Company's Form 10-K (file number 1-11516) for the fiscal year ended December 31, 1997 filed with the Commission on March 30, 1998.

Incorporated by reference to the Company's Registration Statement on Form S-4 (file number 333-61513) filed with the Commission and effective on November 27, 1998.

+ Incorporated by reference to the Company's Form 10-Q (file number 1-11516) for the fiscal quarter ended September 30, 1999 filed with the Commission on November 12, 1999.

** Incorporated by reference to the Company's Form 10-K (file number 1-11516) for the fiscal year ended December 31, 1999 filed with the Commission on March 29, 2000.

++ Incorporated by reference to the Company's Form 10-Q (file number 1-11516) for the fiscal quarter ended September 30, 2001 filed with the Commission on November 9, 2001.

*** Incorporated by reference to the Company's Form 10-K (file number 1-11516) for the fiscal year ended December 31, 2001 filed with the Commission on March 21, 2002.

Incorporated by reference to the Company's Form 10-K (file number 1-11516) for the year ended December 31, 2002, filed with the Commission on March 31, 2003.

+++ Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Amendment No. 1 to this report to be signed on its behalf by the undersigned, thereunto duly authorized.

REMINGTON OIL AND GAS CORPORATION

By: /s/ JAMES A. WATT

James A. Watt
President and Chief Executive Officer

Date: December 16, 2003

EXHIBIT INDEX

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