REMINGTON OIL & GAS CORP
Form 10-K
March 12, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(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, 2003

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 (State or other jurisdiction of incorporation or organization)	75-2369148 (I.R.S. employer Identification No.)
8201 PRESTON ROAD, SUITE 600, DALLAS, TEXAS (Address of principal executive offices)	75225-6211 (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 or any amendment to this Form 10-K. [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 $379,990,179. On March 10, 2004, the number of outstanding shares of common stock, $0.01 par value, was 27,042,398.

REMINGTON OIL AND GAS CORPORATION

TABLE OF CONTENTS

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. Further, our website contains our corporate governance documents including our Code of Business Conduct and Ethics that applies to all directors and employees including our Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer. Persons may obtain free of charge a copy of the reports listed above and our corporate governance documents by written request to the Secretary of the Company.

- 33 employees on December 31, 2003

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 an 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 participants. We currently operate the majority of our offshore properties. As operator, we are able to maintain a greater degree of control over the timing and amount of capital expenditures.

RISKS INVOLVED IN EXPLORATION, DEVELOPMENT, AND PRODUCTION

Exploration, development, and production operations can be risky. These risks fall into two broad categories. First there is the risk that each time we drill a well, the well will not find oil or gas reserves. Even 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 try to mitigate these 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. Much of 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.

Second is the broad category of operating risks. 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:

- Large integrated oil and gas companies

- Independent exploration and production companies

- Private individuals

- Sponsored drilling programs

We compete for:

- Operational, technical, and support staff

- Options and/or leases on properties

- Markets for the sale of oil and gas production

- 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. We use an independent company to market almost all of our offshore gas production and a portion

of our offshore oil production. Because oil and gas are homogenous commodities and other customers and marketers are readily available, we believe that the loss of any of our current customers or our independent marketing company 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 and associated regulations 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. 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, or that the costs associated with such remedial actions will be fully covered by insurance.

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" and "Consolidated Financial Statements and Notes to Consolidated Financial Statements." 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 property as of December 31, 2003, was as follows:

	UNDEVELOPED		DEVELOPED	
	GROSS	NET	GROSS	NET
Offshore	389,302	203,806	205,450	90,834
Onshore	70,012	22,030	29,850	10,052
Total	459,314	225,836	235,300	100,886

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,							
	2004		2005		2006		2007 & BEYOND	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Offshore	--	--	20,278	11,264	118,240	61,120	250,784	131,422
Onshore	27,480	6,596	32,132	6,819	5,230	4,666	5,170	3,949
Total	27,480	6,596	52,410	18,083	123,470	65,786	255,954	135,371

PROVED OIL AND GAS RESERVES

Net proved oil and gas reserves at December 31, 2003, as calculated in a full review of 100% of our properties 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	NET GAS

	RESERVES MBBLS	RESERVES MMCF
Offshore Gulf of Mexico	7,753	137,985
Onshore Gulf Coast	3,866	4,447
Total	11,619	142,432

In 2003 our standardized measure of discounted future net cash flows was $486.3 million. We used December 31, 2003, West Texas Intermediate posted price of $29.25 per barrel and a Gulf Coast spot market price of $5.97 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,					
	2003		2002		2001	
	GROSS	NET	GROSS	NET	GROSS	NET
Oil wells						
Offshore Gulf of Mexico	27	11.05	25	8.67	21	6.72
Onshore Gulf Coast	32	12.25	32	12.89	35	13.61
Total	59	23.30	57	21.56	56	20.33
Gas wells						
Offshore Gulf of Mexico	45	17.37	35	11.19	38	11.02
Onshore Gulf Coast	75	16.36	75	18.52	97	23.65
Total	120	33.73	110	29.71	135	34.67

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 81% of our oil production and approximately 96% of our gas production. In addition, total revenues from offshore Gulf of Mexico oil and gas production during 2003 accounted for approximately 92% of our total oil and gas revenues. We owned varying working interests (5% to 100%) in 113 offshore Gulf of Mexico blocks at December 31, 2003, and currently produce from 36 of these blocks. Seven additional blocks are currently under development. We operate a majority of these 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 2003 we successfully drilled and completed 15 exploratory wells on 13 different properties in the offshore Gulf of Mexico. In addition, we, as operator, constructed and installed or will install 9 production platforms and drilled and completed 3 development wells on 3 different properties.

Our onshore Gulf Coast area properties are principally located in the State of Mississippi and along the Texas Gulf Coast. In 2003, these properties accounted for approximately 19% of our oil production and approximately 4% of our gas production. We drilled a total of 6 wells on our onshore properties during 2003 and completed 4 wells as producers. Our working interests in these wells range from 15% to 100%.

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,								
	2003				2002				
	GROSS		NET		GROSS		NET		GROSS
	PROD.	DRY	PROD.	DRY	PROD.	DRY	PROD.	DRY	PROD.
Exploratory									
Offshore Gulf of Mexico.....	15	7	8.00	3.46	11	4	5.28	1.66	13
Onshore Gulf Coast..........	2	1	.41	1.00	5	3	1.66	0.75	9
Total......................	17	8	8.41	4.46	16	7	6.94	2.41	22
Development									
Offshore Gulf of Mexico.....	3	1	1.37	0.50	2	--	0.66	--	2
Onshore Gulf Coast..........	2	1	0.25	0.20	1	--	0.13	--	5
Total......................	5	2	1.62	0.70	3	--	0.79	--	7

We had an interest in 3 wells (2.10 net) in progress at December 31, 2003, 1 well (0.25 net) in progress at December 31, 2002, and 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	LOW
2004		
First Quarter through March 10, 2004	$21.12	$18.06
2003		
Fourth Quarter	20.30	17.25
Third Quarter	19.48	17.09
Second Quarter	19.59	15.32
First Quarter	19.75	16.63
2002		
Fourth Quarter	17.90	14.19
Third Quarter	19.45	13.46
Second Quarter	21.67	16.95
First Quarter	20.57	15.10

On March 10, 2004, the last reported sales price for our common stock was $19.60 per share. On that date, there were 622 stockholders of record, including 45 stockholders of record of class A common stock and 83 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.

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, 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 following table presents information about our equity compensation plans at December 31, 2003:

	NUMBER OF SECURITIES TO BE ISSUED	WEIGHTED AVERAGE

PLAN CATEGORY	UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER OF SE REMAINING AV FOR FUTURE I
	(A)	(B)	(C)
Equity compensation plans approved by stockholders.....	2,334,333	$10.93	164,01
Equity compensation plans not approved by stockholders.....	259,636	$ 0.00	
Total..........................	2,593,969	$ 9.84	164,01

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").

8

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

- 686,472 shares were awarded. As of December 31, 2003, 385,989 shares have vested, and 40,847 shares have been forfeited. Of the remaining 259,636 shares, 65,563 shares vest on June 17, 2004, and 194,073 shares vest 1/3 on each successive January 17 beginning on January 17, 2004.

- 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 or a change of control, an employee's or director's shares will fully vest. In the event of the long-term disability of an employee, or the employee reaching the retirement age of 65, the shares will fully vest.

9

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.

	2003(1)	2002(1)	2001(1)	2000(1)	1999
	(IN THOUSANDS, EXCEPT PRICES, VOLUMES, AND PER SHARE DATA				

FINANCIAL					
Total revenue........................	$ 183,052	$104,866	$ 116,620	$ 99,661	$ 44,34
Net income (loss)....................	$ 42,924	$ 11,332	$ 8,344	$ 45,044	$ (3,70
Basic income (loss) per share.........	$ 1.61	$ 0.45	$ 0.38	$ 2.10	$ (0.1
Diluted income (loss) per share.......	$ 1.53	$ 0.42	$ 0.35	$ 1.99	$ (0.1
Total assets.........................	$ 359,385	$288,993	$ 240,432	$192,474	$119,32
8 1/4% convertible subordinated notes............................	$ --	$ --	$ --	$ 5,880	$ 5,95
Bank debt............................	$ 18,000	$ 37,400	$ 71,000	$ 27,428	$ 30,02
Stockholders' equity.................	$ 241,877	$193,660	$ 125,338	$102,708	$ 56,05
Total shares outstanding.............	26,912	26,236	22,651	21,564	21,28
Cash Flow					
Net cash flow from operations.......	$ 153,215	$ 71,420	$ 99,025	$ 69,963	$ 19,18
Net cash flow (used in) investing...	$(115,714)	$(92,126)	$(119,242)	$(57,511)	$(25,91
Net cash flow provided by (used in) financing.......................	$ (21,022)	$ 16,258	$ 21,463	$ 1,323	$ (7,93
OPERATIONAL					
Proved reserves(2)					
Oil (MBbls)........................	11,619	13,114	13,865	10,370	7,17
Gas (MMcf).........................	142,432	124,967	111,920	88,650	65,50
Standardized measure of discounted future net cash flows -- end of year(2)............................	$ 486,296	$351,042	$ 199,983	$458,649	$126,86
Average sales price(3)					
Oil (per Bbl)......................	$ 29.43	$ 24.27	$ 23.29	$ 27.69	$ 15.5
Gas (per Mcf)......................	$ 5.40	$ 3.35	$ 4.02	$ 4.02	$ 2.4
Average production (net sales volume)					
Oil (Bbls per day).................	4,863	4,736	3,378	3,234	3,07
Gas (Mcf per day)..................	66,160	47,804	58,265	34,951	26,73

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(1) Financial results for 2003 include charges of $4.4 million and for 2002 include charges of $8.1 million 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.

(2) The quantities of proved oil and gas reserves 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 future discounted net cash flows on year-end prices and costs. 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 consolidated financial statements, and the related notes to consolidated 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.

CRITICAL ACCOUNTING POLICIES

We prepare our consolidated financial statements in this report using accounting principles that are generally accepted in the United States ("GAAP"). 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. The most critical estimates and accounting policies include estimates of proved oil and gas reserves, the related standardized measure of discounted future net cash flows, and the use of successful efforts accounting method for oil and gas expenditures. The calculation of depreciation, depletion and amortization of our oil and gas properties and the impairment of those properties are affected by the estimated oil and gas reserves and the successful efforts method of accounting. In addition, we use multiple estimated data to compute and record our asset retirement obligations. Finally, our general and administrative expenses are affected by the method in which we measure and record stock based compensation expense and, to a lesser extent, assumptions related to our defined benefit pension plans. We have included a more detailed discussion of these critical estimates and accounting policies in the following sections of this item: Long-Term Strategy and Business Developments, Liquidity and Capital Resources, and Results of Operations. Our Notes to Consolidated Financial Statements included in this report also have a more comprehensive discussion of our significant accounting policies.

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 (on a per Mcf equivalent (Mcfe) basis) 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 $339.8 million in oil and gas properties, found 158.2 Bcfe of proved reserves and replaced 173% of our production at an average finding and development cost of $2.15 per Mcfe. The following table reflects our results during the last three years.

	2003	% INCREASE (DECREASE)	2002	% INCREASE (DECREASE)	2001

Production:					
Oil MBbls	1,775	3%	1,729	40%	1,233
Gas MMcf	24,149	38%	17,448	(18)%	21,267
Total MMcfe(1)	34,799	25%	27,822	(3)%	28,665
Proved reserves:					
Oil MBbls	11,619	(11)%	13,114	(5)%	13,865
Gas MMcf	142,432	14%	124,967	12%	111,920
Total MMcfe(1)	212,146	4%	203,651	4%	195,110
Operating costs per Mcfe	$ 0.60	3%	$ 0.58	4%	$ 0.56
Finding and development costs per Mcfe(2)	$ 2.69	12%	$ 2.40	43%	$ 1.68
Percentage of production replaced(3)	124%		150%		253%

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

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

The implementation of our long-term strategy requires that we continually incur significant capital expenditures in order to replace current production and find and develop new oil and gas reserves. In order to finance our capital and exploration program, we depend on cash flow from operations or bank debt and equity offerings as discussed below in Liquidity and Capital Resources.

Operating costs on a Mcfe produced basis have increased slightly over the past three years from $0.56 to $0.60 or approximately 7%. Finding and development costs have increased from $1.68 per Mcfe in 2000 to $2.69 per Mcfe in 2003. These increased costs reflect the difficulty of finding new reserves in the offshore Gulf of Mexico shelf environment. These higher costs also reflect negative reserve revisions that have occurred in 2002 and 2003. These negative revisions were the result of certain reservoirs performing at rates lower than anticipated by our independent reserve engineers. If the reserve revisions are removed from the finding and development cost calculations, annual finding and development costs and percentage of production replaced would have been as follows:

	2003	2002	2001
Finding and development costs	$2.27	$2.02	$1.83
Percentage of production replaced	147%	179%	233%

12

Although we and our independent reservoir engineers utilize accepted engineering techniques to evaluate the future performance of reservoirs, variations in these estimates can and will occur.

PROVED RESERVE ESTIMATES

While parts of our long-term strategy (such as increased production or operating costs per Mcfe) can be accurately measured by reference to actual data, other measurements (such as an increase in oil and gas reserves or finding costs per Mcfe) rely heavily on estimated information, subject to later revisions. In addition, the standardized measure of discounted future net cash flows relies on these estimates of oil and gas reserves using commodity prices and costs at year end.

Independent reserve engineers prepare the estimates of our oil and gas reserves 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.

In our 2003 year-end reserve report we used December 31, 2003, West Texas Intermediate posted price of $29.25 per barrel and a Gulf Coast spot market price of $5.97 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. Future global economic and political events will most likely result in significant fluctuations in future oil prices. In addition, cold weather during December 2003 and into the first quarter of 2004 in the United States has resulted in significant fluctuations in natural gas prices.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operations for the year ended December 31, 2003, increased by $81.8 million, or 115%, compared to the prior year primarily due to a 25% increase in production and an increase in oil and gas prices throughout the entire year. We expect our cash flow provided by operations for 2004 to increase because of higher projected production from new properties, combined with oil and gas prices consistent with 2003 and steady operating, general and administrative, interest and financing costs per Mcfe.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but 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's presence in the Gulf, or as in the case of Hurricane Lili in 2002, damage production facilities so that we cannot produce from 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.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production (usually less than 33%) through the use of forward sale agreements. Currently we have no such arrangements in place. See additional discussion under Commodity Price Risk in Item 7A. Quantitative and Qualitative Disclosures about Market

Risk.

Changes in our working capital accounts from 2002 to 2003 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 as a result of increased operating activities (drilling wells and facilities construction) at year end. Due to the increase in operating activities our accounts payable balance increased by $10.7 million which increased our cash flow from operations. Cash flow provided by

operations also increased due to a decrease in prepaid expenses and other current assets primarily because of a decrease in prepaid drilling costs on non-operated properties.

We incurred capital and exploration expenditures totaling $116.4 million during 2003. The capital expenditures included $3.8 million for leasehold acquisition, $54.1 million for exploration costs, $58.5 million for development costs including platform and facilities construction. During the year, we built and installed, or will install in 2004, 9 offshore platforms and facilities. In addition, in 2003 we drilled 25 exploration wells and 7 development wells and had 3 wells in progress at year end.

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 $104.0 million for capital and exploration expenditures in 2004. Our 2004 capital and exploration budget includes $56.0 million for 29 exploratory wells. We project that we will spend $47.6 million on 22 wells in the Gulf of Mexico and $8.4 million on 7 onshore wells in South Texas and Mississippi. The budget also includes $21.0 million for platforms and development drilling. The remaining $27.0 million will be allocated to leasehold acquisitions, seismic acquisitions, and workovers.

If our exploratory drilling results in significant new discoveries, we will have to expend 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 access sufficient additional capital through additional bank financing and /or offerings of debt or equity securities.

Effective May 1, 2003, we agreed with our lenders to increase our borrowing base from $75.0 million to $100.0 million and to extend the maturity of the loan facility from May 3, 2004 to May 3, 2006. As of December 31, 2003, we had $18.0 million borrowed under the facility. The banks review the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit. Additionally, we have agreed not to pay dividends. 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. If we do not comply with these covenants on a continuing basis, 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.

On June 19, 2003, we filed a shelf registration statement to issue up to $200.0 million of common stock, debt securities, preferred stock, and or warrants. The Securities and Exchange Commission declared the shelf registration statement effective December 18, 2003.

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2003.

	PAYMENTS DUE BY PERIOD				
	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS
			(IN THOUSANDS)		
Contractual obligations					
Bank debt......................	$18,000	$ --	$18,000	$ --	$ --
Purchase commitments...........	$ 1,559	$1,559	$ --	$ --	$ --
Office lease...................	$ 2,027	$ 441	$ 971	$615	$ --
Total..........................	$21,586	$2,000	$18,971	$615	$ --

On December 31, 2003, our current assets exceeded our current liabilities by $18.9 million. Our current ratio was 1.32 to 1.00.

14

RESULTS OF OPERATIONS

In 2003, we achieved net income totaling $42.9 million or $1.61 basic income per share, and $1.53 diluted income per share, compared to a net income of $11.3 million or $0.45 basic income per share and $0.42 diluted income per share in 2002. The increase in net income resulted primarily from increased oil and gas production and sales prices. In addition to oil and gas production and prices, certain accounting policies discussed below can cause our net income to vary significantly from period to period because of events or circumstances which trigger recognition of expenses for unsuccessful wells or impairments of properties. Further, we calculated certain expenses using estimates of oil and gas reserves that can vary significantly.

OIL AND GAS SALES REVENUE

The following table discloses the net oil and gas production volumes, sales, and sales prices for each of the three years ended December 31, 2003, 2002, and 2001.

	2003	% INCREASE (DECREASE)	2002	% INCREASE (DECREASE)	2001
Oil production volume (MBbls).....	1,775	3%	1,729	40%	1,233
Oil sales revenue.................	$ 52,233	24%	$ 41,969	46%	$28,717
Price per Bbl.....................	$ 29.43	21%	$ 24.27	4%	$ 23.29
Increase in oil sales revenue due					

to:					
Change in prices..................	$ 8,922		$ 1,208		
Change in production volume.......	1,342		12,044		
	--------		--------		
Total increase (decrease) in oil sales revenue...................	$ 10,264		$ 13,252		
	========		========		
Gas production volume (MMcf)......	24,149	38%	17,448	(18)%	21,267
Gas sales revenue.................	$130,346	123%	$ 58,412	(32)%	$85,504
Price per Mcf.....................	$ 5.40	61%	$ 3.35	(17)%	$ 4.02
Increase (decrease) in gas sales revenue due to:					
Change in prices..................	$ 35,768		$(14,249)		
Change in production volume.......	36,166		(12,843)		
	--------		--------		
Total increase (decrease) in gas sales revenue...................	$ 71,934		$(27,092)		
	========		========		

Oil sales revenue during 2003 increased by $10.3 million, or 24%, compared to 2002 because average oil prices increased by $5.16 per barrel, or 21% and oil production increased by 46,000 barrels, or 3%. During 2002, oil sales revenue increased by $13.3 million, or 46%, compared to 2001 because oil production increased by 496,000 barrels, or 40%, and average oil prices increased by $0.98 or 4%. The increase in oil production came primarily from new properties in the offshore Gulf of Mexico partially offset by natural depletion of the existing producing properties in the Gulf Coast area and the sale of certain properties in South Texas in April 2002.

Gas sales revenue during 2003 increased by $71.9 million or 123% compared to 2002 because of higher average gas prices and increased production. Average gas prices increased from $3.35 per Mcf in 2002 to $5.40 per Mcf, or 61%, in 2003, causing gas sales revenues to increase by $35.8 million. Production increased by 6.7 Bcf, or 38%, primarily because of gas production from new properties in the offshore Gulf of Mexico. During 2002, 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 in production from this property was partially offset by increased gas production from new offshore properties.

During 2002, we sold certain South Texas properties at a $4.1 million gain. This gain in 2002 accounts for the decrease in other income during 2003 when compared to 2002 and the increase in 2002 when compared to 2001.

OPERATING COSTS AND EXPENSES

Total operating costs during 2003 increased by $4.8 million, or 29%, compared to 2002, due to the increase in the number of operating properties. However, operating costs per Mcfe increased by only $0.02 to $0.60 during 2003. The following table presents the major components of our operating costs on a per Mcfe basis.

	YEARS ENDING DECEMBER 31,					
	2003		2002		2001	
	TOTAL	PER MCFE	TOTAL	PER MCFE	TOTAL	PER MCFE
Direct operating expense....	$15,709	$0.45	$11,664	$0.42	$10,443	$0.36
Overhead....................	346	0.01	266	0.01	105	0.00
Workovers...................	1,597	0.04	1,434	0.05	2,451	0.09
Advalorum taxes.............	74	0.00	28	0.00	39	0.00
Production taxes............	870	0.03	680	0.02	1,303	0.05
Transportation..............	2,314	0.07	2,078	0.08	1,606	0.06
Total.......................	$20,910	$0.60	$16,150	$0.58	$15,947	$0.56

EXPLORATION EXPENSES -- 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 expenses 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 accurately 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.

During 2003, exploration expenses increased by $9.8 million, or 63%, compared to 2002 primarily because of a $9.2 million increase in dry hole costs. In addition, geological and geophysical expenses increased by $628,000 because of higher seismic expenses in 2003 compared to 2002. Exploration expenses for 2002 increased by $2.5 million, or 19%, because of increased dry hole costs compared to 2001, partially offset by a $2.7 million decrease in seismic expenses in 2002. 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 75 exploration wells, of which 20 were considered dry holes resulting in a 73% success ratio on exploratory wells. Our dry hole costs charged to expense during this period totaled $48.4 million out of total exploratory drilling costs of $146.3 million. It is impossible to accurately predict specific dry holes; however, based on past experience, we estimate that between 20% and 30% of our exploration wells and exploration drilling costs will be dry holes.

DEPLETION, DEPRECIATION, AND AMORTIZATION OF OIL AND GAS PROPERTIES AND ASSET RETIREMENT OBLIGATIONS

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. Downward revisions in reserves increase the DD&A per unit and reduce our net income; likewise, upward revisions lower the DD&A per unit and increase our net income. Depreciation, depletion and amortization expense recorded in 2003 increased by $17.2 million, or 45%, compared to the prior year. On a per Mcfe basis, depreciation, depletion and amortization per Mcfe increased to $1.60 in 2003 from $1.38 in 2002 reflecting the increased costs for finding reserves in the Gulf of Mexico and some negative revisions in our oil and gas reserves. 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 and depreciation, depletion and amortization per Mcfe increased to $1.38 from $1.33 in 2001.

We adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003. 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. We then adjust the current estimated obligation for estimated inflation and market risk contingencies to the projected settlement date of the liability. The result is then discounted to a present value from the projected settlement date to the date the asset was first placed in service. As of January 1, 2003, we recorded the present value of the asset retirement obligation as an additional property cost and as an asset retirement liability. A combination of the amortization of the additional property cost (using the unit of production method) and the accretion of the discounted liability is recorded as a component of our depreciation, depletion and amortization of oil and gas properties.

Prior to this adoption, we accrued an estimated dismantlement, restoration and abandonment liability using the unit of production method over the life of a property and included the accrued amount in depreciation, depletion and amortization expense. The total accrued liability ($5.5 million at December 31, 2002) was reflected as additional accumulated depreciation, depletion and amortization of oil and gas properties on our balance sheet.

In conformity with the new statement we recorded the cumulative effect of this accounting change as of January 1, 2003, as if we had used this method in the prior years. At January 1, 2003, we increased our oil and gas properties by $9.0 million, recorded $11.8 million as an Asset Retirement Obligation liability and reduced our accumulated depreciation by $2.8 million ($5.5 million accrued dismantlement in prior years less accumulated depreciation, depletion and amortization of $2.7 million on the increased property costs). The adoption of the new standard had no material effect on our net income. The following pro forma data summarizes our net income and net income per share for the years ended December 31, 2003, 2002 and 2001 as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS EXCEPT PER SHARE AMOUNTS)		
Net income, as reported	$42,924	$11,332	$8,344
Pro forma adjustment to reflect retroactive adoption of SFAS 143	34	(85)	(371)

Pro forma net income	$42,958	$11,247	$7,973
Net income per share:			
Basic -- as reported	$ 1.61	$ 0.45	$ 0.38
Basic -- pro forma	$ 1.61	$ 0.44	$ 0.36
Diluted -- as reported	$ 1.53	$ 0.42	$ 0.35
Diluted -- pro forma	$ 1.53	$ 0.41	$ 0.33

IMPAIRMENT OF OIL AND GAS PROPERTIES

Because we account for our proved oil and gas properties separately, we also 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 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. We recognized impairment expenses during the last three years as follows:

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Unproved properties	$1,136	$1,640	$ 616
Proved properties	3,311	6,441	10,000
Total impairment expense	$4,447	$8,081	$10,616

The impairment of unproved leasehold costs includes an amortization of the aggregate individually insignificant properties (adjusted by an estimated rate of future successful development) over an average lease term and the specific impairment of individually significant properties. During 2003 and 2002 the amortization of the individually insignificant properties totaled $917,000 and $1.1 million, respectively. The remaining impairments in these two years resulted from impairment of significant properties due to unsuccessful drilling results. In 2001, prior to our adoption of this amortization method, the impairment expense resulted from the actual (due to unsuccessful exploration results) or impending forfeiture of leaseholds. The effect of the change in estimating our impairment of unproved properties was not material to our financial statements.

We analyze our proved properties for impairment indicators based on the proved reserves as determined by our independent reserve engineers. The properties impaired in 2003 primarily consisted of two properties in the Gulf of Mexico which totaled $2.4 million and one property in the onshore Gulf Coast totaling $855,000, and 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 impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

GENERAL AND ADMINISTRATIVE -- ACCOUNTING FOR STOCK BASED COMPENSATION AND DEFINED BENEFIT PENSION PLAN

General and administrative expenses during 2003 increased by $1.5 million, or 22% compared to 2002. General and administrative expenses increased by $0.04 per Mcfe to $0.29 in 2003 from $0.25 in 2002. General and administrative expense in 2002 decreased by $2.5 million due to a reduction in stock based compensation. Stock based compensation expense which is included in general and administrative expense totaled $1.3 million in 2003, $1.4 million in 2002 and $3.5 million in 2001.

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, $1.4 million in 2002, and $1.3 million in 2003 as stock based compensation expense related to the grants. At December 31, 2003, $1.7 million of the unearned compensation remained unamortized and will be amortized as the shares vest during the next two 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.

Total assets at fair market value (public market prices for equity and fixed income mutual funds) for our two defined benefit pension plans were $6.0 million which exceeded the total accumulated benefit obligation as of December 31, 2003. We recorded $542,000 in pension expense and contributed $850,000 to the plans during 2003. 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 target asset allocation of equities (75%) and fixed income securities (25%). If however, we reduced the assumed rate of return by 50 basis points, our 2003 pension plan expense would have increased by approximately $21,000 and our net income would have decreased 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 6.5% in 2002 to 6.0% in 2003 and 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 had decreased by another 50 basis points, our 2003 pension expense would have increased by approximately $268,000 and our net income would have decreased by approximately $174,000.

SETTLEMENTS EXPENSE AND INTEREST AND FINANCING EXPENSE

During the second quarter of 2001, we settled the Phillips litigation and charged $13.5 million to settlement expense. Interest and financing expense decreased during the past two years because of lower interest rates and lower outstanding debt.

INCOME TAXES

During 2003, income taxes increased by $17.5 million compared to 2002 and increased by $2.5 million during 2002 compared to 2001 as a result of increased income before taxes. The effective tax rate increased slightly in 2003 due to an increase in state taxes.

NEW ACCOUNTING PRONOUNCEMENTS

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 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, 2003, we had net leaseholds cost of approximately $34.8 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.

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, 2003, the unpaid principal balance under the line was $18.0 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, 2003, and December 31, 2002, Libor had changed by one full percentage point (100 basis points) the fair value of our revolving debt would have changed by approximately $45,000 and $93,000 respectively. 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. We currently have no such arrangements in place.

21

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

INDEX TO FINANCIAL STATEMENTS

22

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 sheets of Remington Oil and Gas Corporation ("the Company"), a Delaware corporation, as of December 31, 2003, and 2002 and the related consolidated statements of income, stockholders' equity and cash flows for the years then ended. 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 year then ended 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 consolidated financial position of Remington Oil and Gas Corporation as of December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003 the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

As discussed above, the consolidated financial statements of Remington Oil and Gas Corporation as of December 31, 2001, and for the year then ended, 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 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 (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 in Note 1 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 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 financial statements taken as a whole.

/s/ ERNST & YOUNG LLP

Dallas, Texas
March 5, 2004

23

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 years ended December 31, 2002 and December 31, 2003, 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 sheets as of December 31, 2000 and December 31, 2001, and the consolidated statements of income, stockholders' equity, and cash flows for the years ended December 31, 1999 and December 31, 2000, have not been included in the accompanying financial statements.

24

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED BALANCE SHEETS

	AT DECEMBER 31,	
	2003	2002
	(IN THOUSANDS, EXCEPT SHARE DATA)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 31,408	$ 14,929
Accounts receivable	43,004	32,555
Prepaid drilling costs	476	3,115
Prepaid expenses and other current assets	2,370	1,863
TOTAL CURRENT ASSETS	77,258	52,462
PROPERTIES		
Oil and gas properties (successful-efforts method)	609,599	510,921
Other properties	3,450	3,182
Accumulated depreciation, depletion and amortization	(333,011)	(279,722)
TOTAL PROPERTIES	280,038	234,381
OTHER ASSETS		
Other assets	2,089	2,150
TOTAL OTHER ASSETS	2,089	2,150
TOTAL ASSETS	$ 359,385	$ 288,993

LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 58,266	$ 47,523
Short-term notes payable and current portion of other long-term payables	45	1,715
TOTAL CURRENT LIABILITIES	58,311	49,238
LONG-TERM LIABILITIES		
Notes payable	18,000	37,400
Other long-term payables	--	1,503
Asset retirement obligations	12,446	--
Deferred income taxes	28,751	7,192
TOTAL LONG-TERM LIABILITIES	59,197	46,095
TOTAL LIABILITIES	117,508	95,333
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, 26,946,768 shares issued and 26,912,409 shares outstanding in 2003, 26,327,195 shares issued and 26,236,459 shares outstanding in 2002	269	263
Additional paid-in capital	120,925	115,827
Restricted common stock	3,156	5,468
Unearned compensation	(1,668)	(3,192)
Treasury stock (56,377 shares common stock in 2002, at cost)	--	(977)
Retained earnings	119,195	76,271
TOTAL STOCKHOLDERS' EQUITY	241,877	193,660
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 359,385	$ 288,993

See accompanying Notes to Consolidated Financial Statements.

25

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
REVENUES			
Oil sales	$ 52,233	$ 41,969	$ 28,717
Gas sales	130,346	58,412	85,504
Interest income	161	198	975

Gain on sale of assets and other income	312	4,287	1,424
TOTAL REVENUES	183,052	104,866	116,620
COSTS AND EXPENSES			
Operating costs and expenses	20,910	16,150	15,947
Exploration expenses	25,416	15,623	13,100
Depreciation, depletion, and amortization	55,694	38,528	38,263
Impairment of oil and gas properties	4,447	8,081	10,616
General and administrative	8,408	6,912	9,409
Settlements expense	--	--	13,524
Interest and financing expense	1,635	2,145	3,829
TOTAL COSTS AND EXPENSES	116,510	87,439	104,688
INCOME BEFORE TAXES	66,542	17,427	11,932
Income taxes	23,618	6,095	3,588
NET INCOME	$ 42,924	$ 11,332	$ 8,344
BASIC INCOME PER SHARE	$ 1.61	$ 0.45	$ 0.38
DILUTED INCOME PER SHARE	$ 1.53	$ 0.42	$ 0.35

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	R E
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)		(977)	
Tax benefit from exercise of stock options		1,754				

Balance December 31, 2002.....	263	115,827	5,468	(3,192)	(977)	
Net income...................						
Amortization of unearned compensation................				1,318		
Forfeit contingent stock grant shares.....................			(206)	206		
Common stock issued...........	7	4,998	(2,106)		(808)	
Tax benefit from exercise of stock options...............		1,884				
Treasury stock retired........	(1)	(1,784)			1,785	
Balance December 31, 2003.....	$269	$120,925	$ 3,156	$(1,668)	$ --	$

See accompanying Notes to Consolidated Financial Statements.

REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
CASH FLOW PROVIDED BY OPERATIONS			
NET INCOME...	$ 42,924	$ 11,332	$ 8,344
ADJUSTMENTS TO RECONCILE NET INCOME			
Depreciation, depletion, and amortization...............	55,694	38,528	38,263
Deferred income tax expense.............................	23,443	6,095	3,600
Amortization of deferred finance charges................	207	228	172
Deferred net profits expense............................	--	--	1,270
Impairment of oil and gas properties....................	4,447	8,081	10,616
Dry hole costs..	23,993	14,828	9,589
Cash paid for dismantlement and restoration liability....	(1,631)	(247)	(622)
Stock based compensation................................	1,565	1,609	3,696
Gain on sale of properties..............................	--	(4,095)	(201)
CHANGES IN WORKING CAPITAL			
Decrease (increase) in accounts receivable...............	(10,483)	(13,099)	1,580
Decrease (increase) in prepaid expenses and other current assets...	2,313	(5,131)	526
Increase in accounts payable and accrued expenses........	10,743	13,291	10,600
Decrease (increase) in restricted cash...................	--	--	11,592
NET CASH FLOW PROVIDED BY OPERATIONS......................	153,215	71,420	99,025
CASH FROM INVESTING ACTIVITIES			
Payments for capital expenditures.......................	(115,714)	(99,865)	(119,673)
Proceeds from property sales............................	--	7,739	431
NET CASH (USED IN) INVESTING ACTIVITIES....................	(115,714)	(92,126)	(119,242)
CASH FROM FINANCING ACTIVITIES			
Proceeds from notes payable.............................	--	17,000	51,500

Payments on notes payable and other long-term payables...	(22,573)	(54,393)	(12,464)
Purchase common stock....................................	(809)	(977)	(20,644)
Commitment fee on line of credit.........................	(293)	--	(307)
Common stock issued......................................	2,653	54,628	3,378
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES........	(21,022)	16,258	21,463
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS.......	16,479	(4,448)	1,246
Cash and cash equivalents at beginning of period.........	14,929	19,377	18,131
CASH AND CASH EQUIVALENTS AT END OF PERIOD.................	$ 31,408	$ 14,929	$ 19,377
Cash paid for interest.....................................	$ 1,702	$ 2,552	$ 2,925
Cash paid (received) for taxes.............................	$ 175	$ --	$ (12)
Non-cash issuance of common stock (Note 6).................	$ --	$ --	$ 21,250

See accompanying Notes to Consolidated Financial Statements.

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 AND CASH EQUIVALENTS

Cash equivalents consist of highly liquid investments that mature within three months or less when purchased. Our cash equivalents consist primarily of 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 $31.3 million and $14.8 million at December 31, 2003 and 2002, respectively. At December 31, 2003, 3 companies accounted for approximately 65% of the total accounts receivable and at December 31, 2002, 3 companies accounted for approximately 58% of the total accounts receivable. Oil and gas are fungible commodities in high demand from numerous customers; however, during 2003 we sold oil and gas to four major customers who accounted for 17%, 16%, 14% and 13% of our total revenues. The sale of oil and gas to three major customers accounted for 54%, 23% and 11% of our total oil and gas revenues in 2002. We do not believe that the loss of any of these customers would have a material adverse effect on our financial position or results of operations because we believe that they can be replaced due to the high demand for oil and gas.

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 expense unsuccessful exploration wells and geological and geophysical costs when incurred. We amortize the capitalized costs using the units-of-production method, converting to gas equivalent units by using the ratio of 1 barrel of oil equal to 6 Mcf of gas.

We review our oil and gas properties for impairment whenever events or circumstances indicate that the net book value of the assets may not be recoverable. 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.

The impairment of unproved leasehold costs includes an amortization of the aggregate individually insignificant properties (adjusted by an estimated rate of future successful development) over an average lease term and, if events or circumstances indicate, a specific impairment of individually significant properties.

Other properties include improvements on the leased office space and office computers and equipment. We depreciate these assets using the straight-line method over their estimated useful lives, which 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 the long-term portion of 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 $376,000, which is CKB Petroleum's claim under Collateral Assignment Split Dollar Insurance Agreements among CKB Petroleum and Don D. Box (a former officer and director) and two of his brothers.

ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses were as follows:

	AT DECEMBER 31,	
	2003	2002
	(IN THOUSANDS)	
Accounts payable -- trade	$41,330	$32,908
Advance billings	11,266	8,353
Royalties and other revenue payable	5,670	5,850
Other current payables	--	412
Total accounts payable and accrued expenses	$58,266	$47,523

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, 2003, 2002, and 2001, we incurred transportation costs totaling $2.3 million, $2.1 million and $1.6 million, 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. 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,		
	2003	2002	2001
	(IN THOUSANDS EXCEPT PER SHARE AMOUNTS)		
As reported:			
Net income	$42,924	$11,332	$ 8,344
Basic income per share	$ 1.61	$ 0.45	$ 0.38
Diluted income per share	$ 1.53	$ 0.42	$ 0.35
Stock based compensation (net of tax at statutory rate of 35%) included in net income as reported	$ 1,017	$ 1,046	$ 2,402
Stock based compensation (net of tax at statutory rate of 35%) if using the fair value method as applied to all awards	$ 3,146	$ 2,531	$ 4,248
Pro forma (if using the fair value method applied to all awards):			
Net income	$40,795	$ 9,847	$ 6,498
Basic income per share	$ 1.53	$ 0.39	$ 0.30
Diluted income per share	$ 1.46	$ 0.36	$ 0.27
Weighted average shares used in computation			
Basic	26,628	25,294	21,979
Diluted	27,987	27,122	24,414

The fair value of each option grant for the years ended December 31, 2003, 2002, and 2001 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,

	2003	2002	2001
Expected life (years)	7	10	10
Interest rate	3.73%	4.17%	5.13%
Volatility	65.27%	61.62%	62.56%
Dividend yield	0%	0%	0%

As required, the pro-forma disclosures above include options granted since January 1, 1995. All of our outstanding or previously-exercised options were granted after 1995.

SEGMENT REPORTING

We operate in only one business segment.

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 current income taxes and deferred income taxes. Current income tax expense or benefit equals the amount expected to be calculated on our income tax returns 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 plus the tax benefit derived from the exercise of employee stock options. We determine the amount of our deferred income tax asset or liability by multiplying the enacted tax rates by the temporary differences, net operating or capital loss carry-forwards plus any tax credit carry-forwards. The tax rates used are the effective rates applicable for the year in which we expect the temporary differences or carry-forwards to reverse.

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 options 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,		
	2003	2002	2001
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		

Net income available for basic income per share	$42,924	$11,332	$ 8,344
Interest expense on Convertible Notes (net of tax)	--	--	188
Net income available for diluted income per share	$42,924	$11,332	$ 8,532
Basic income per share	$ 1.61	$ 0.45	$ 0.38
Diluted income per share	$ 1.53	$ 0.42	$ 0.35
Weighted average common shares for basic income per share	26,628	25,294	21,979
Dilutive stock options outstanding (treasury stock method)	1,099	1,378	1,453
Common stock grant	260	450	663
Shares assumed issued by conversion of Notes	--	--	319
Total common shares for diluted income per share	27,987	27,122	24,414

ADOPTED AND NEW ACCOUNTING POLICIES

We adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003. 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. We then adjust the current estimated obligation for estimated inflation and market risk contingencies to the projected settlement date of the liability. The result is then discounted to a present value from the projected settlement date to the date the asset was first placed in service. We recorded the present value of the asset retirement obligation as an additional property cost and as an asset retirement liability. A combination of the amortization of the additional property cost (using the unit of production method) and the accretion of the discounted liability is recorded as a component of our depreciation, depletion and amortization of oil and gas properties.

Prior to this adoption, we accrued an estimated dismantlement, restoration and abandonment liability using the unit of production method over the life of a property and included the accrued amount in depreciation, depletion and amortization expense. The total accrued liability ($5.5 million at December 31, 2002) was reflected as additional accumulated depreciation, depletion and amortization of oil and gas properties on our balance sheet.

In conformity with the new statement we recorded the cumulative effect of this accounting change as of January 1, 2003, as if we had used this method in the prior years. At January 1, 2003, we increased our oil and gas properties by $9.0 million, recorded $11.8 million as an Asset Retirement Obligation liability and reduced our accumulated depreciation by $2.8 million ($5.5 million accrued dismantlement in prior years less accumulated depreciation, depletion and amortization of $2.7 million on the increased property costs). The adoption of the new standard had no material effect on our net income. The following pro forma data summarize our net income and net income per share for the years ended December 31, 2003, 2002 and 2001

as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

	YEARS ENDED DECEMBER 31, 2003	2002	2001
	(IN THOUSANDS EXCEPT PER SHARE AMOUNTS)		
Net income, as reported	$42,924	$11,332	$8,344
Pro forma adjustment to reflect retroactive adoption of SFAS 143	34	(85)	(371)
Pro forma net income	$42,958	$11,247	$7,973
Net income per share:			
Basic -- as reported	$ 1.61	$ 0.45	$ 0.38
Basic -- pro forma	$ 1.61	$ 0.44	$ 0.36
Diluted -- as reported	$ 1.53	$ 0.42	$ 0.35
Diluted -- pro forma	$ 1.53	$ 0.41	$ 0.33

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 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, 2003, we had net leaseholds costs of $34.8 million and at December 31, 2002, we had net leasehold costs of $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 January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires us to consolidate certain entities that are determined to be variable interest entities. If an entity lacks sufficient equity to carry on its principal activities, the equity investors of the entity cannot make decisions about the entity's activities, or the entity's equity investors neither absorbs losses or benefits from gains, it is considered a variable interest entity. We have reviewed our financial arrangements and have not identified any such entities.

REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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,					
	2003			2002		
	PROVED	UNPROVED	TOTAL	PROVED	UNPROVED	TOTAL
	(IN THOUSANDS)					
Onshore	$ 66,129	$ 2,510	$ 68,639	$ 58,227	$ 3,511	$ 61,738
Offshore	524,128	16,832	540,960	432,103	17,080	449,183
Total	590,257	19,342	609,599	490,330	20,591	510,921
Accumulated depreciation, depletion and amortization	(330,432)	--	(330,432)	(277,330)	--	(277,330
Net oil and gas properties	$ 259,825	$19,342	$ 279,167	$ 213,000	$20,591	$ 233,591

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

	FOR YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(UNAUDITED, IN THOUSANDS)		
Unproved acquisition costs	$ 2,370	$ 4,215	$ 9,885
Proved acquisition costs	1,466	--	5,000
Exploration costs	54,138	45,381	46,825
Development costs	58,475	50,904	61,145
Discounted estimate of future asset retirement costs	9,963	--	--
Total	$126,412	$100,500	$122,855

We recognized impairment expenses shown in the table below:

	FOR YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Unproved properties	$1,136	$1,640	$ 616
Proved properties	3,311	6,441	10,000
Total impairment expense	$4,447	$8,081	$10,616

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 analyze proved properties for impairment indicators based on the proved reserves as determined by our independent reserve engineers. The properties impaired in 2003 primarily consisted of two properties in the Gulf of Mexico which totaled $2.4 million and one property in the onshore Gulf Coast, and 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 impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

The following table summarizes our asset retirement obligation on a pro forma basis as if the provisions of SFAS 143 had been applied when the properties were placed in service:

AT DECEMBER 31,

	2003	2002	2001
	(UNAUDITED IN THOUSANDS)		
Beginning of period	$11,807	$ 8,305	$6,328
New properties and changes in estimated cash flow and asset life	1,393	3,114	2,148
Settlement of liabilities	(1,631)	(247)	(622)
Accretion of liability	877	635	451
End of period	$12,446	$11,807	$8,305

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

BANK CREDIT FACILITY

As of December 31, 2003, our amended credit facility of $150.0 million has a borrowing base of $100.0 million. The following schedule reflects certain information about the line of credit for the last two years.

	AT DECEMBER 31,	
	2003	2002
	(IN THOUSANDS)	
Borrowing base	$100,000	$75,000
Outstanding balance	18,000	37,400
Available amount	$ 82,000	$37,600

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, 2006, 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. If we do not 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 decrease or propose an increase to the borrowing base at their discretion relative to the new estimate of proved oil and gas reserves.

FAIR VALUE OF INDEBTEDNESS

We estimate that the fair value of our long-term indebtedness, including the current maturities of such obligations, is approximately $18.0 million at December 31, 2003 and $40.6 million at December 31, 2002. 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($)
2001	$433,000
2002	$441,000
2003	$441,000
2004	$441,000
2005	$479,000
2006	$492,000
2007	$492,000
2008	$123,000

We have no material pending legal proceedings.

NOTE 5 -- COMMON STOCK, PREFERRED STOCK AND DIVIDENDS

We have 100.0 million shares of common stock and 25.0 million shares of "blank check" preferred stock authorized. 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.

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 previous royalty settlement to 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. These shares were cancelled.

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, 2003, 2002, and 2001, and changes during the years ending on those dates is presented below:

	AT DECEMBER 31,					
	2003		2002		2001	
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHT AVERAG EXERCI PRICE
Outstanding at beginning of year.........................	2,552,219	$ 8.68	2,598,700	$ 6.72	2,581,503	$ 5.2
Granted.......................	360,000	$18.66	400,000	$17.20	345,000	$15.3
Exercised.....................	(559,553)	$ 5.44	(440,978)	$ 4.87	(327,803)	$ 4.3
Forfeited.....................	(18,333)	$16.82	(5,503)	$ 9.04	--	$ -
Outstanding at end of year.....	2,334,333	$10.93	2,552,219	$ 8.68	2,598,700	$ 6.7
Options exercisable at year-end....................	1,592,667	$ 7.81	1,613,554	$ 6.54	1,441,384	$ 6.1
Weighted-average fair value of options granted during the year........................		$12.33		$12.64		$11.5

The options outstanding at December 31, 2003, have a weighted-average remaining contractual life of 6.76 years and an exercise price ranging from $3.125 to $20.34 per share. A breakdown of the options outstanding at December 31, 2003 by price range is presented below:

OPTION PRICE RANGE	NUMBER	WEIGHTED AVERAGE EXERCISE PRICE	WEIGHTED AVERAGE REMAINING LIFE (YEARS)	NUMBER EXERCISABLE	WEIGHTE PRICE O EXERC
$3.125 - $4.25...........	648,941	$ 3.88	6.09	648,946	$
$5.0625 - $6.9375.........	393,020	$ 6.38	3.82	393,020	$
$8.625 - $9.00...........	110,000	$ 8.97	4.62	110,000	$
$11.00 - $15.32..........	415,367	$13.94	7.11	317,911	$1
$16.55 - $20.34..........	767,000	$17.87	9.31	140,334	$1

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,		
	2003	2002	2001
	(IN THOUSANDS)		
As reported:			
Net income..	$42,924	$11,332	$8,344
Basic income per share..................................	$ 1.61	$ 0.45	$ 0.38
Diluted income per share................................	$ 1.53	$ 0.42	$ 0.35
Stock based compensation (net of tax at statutory rate of 35%) included in net income as reported..................	$ 1,017	$ 1,046	$2,402
Stock based compensation (net of tax at statutory rate of 35%) if using the fair value method as applied to all awards..	$ 3,146	$ 2,531	$4,248
Pro forma (if using the fair value method applied to all awards):			
Net income..	$40,795	$ 9,847	$6,498
Basic income per share..................................	$ 1.53	$ 0.39	$ 0.30
Diluted income per share................................	$ 1.46	$ 0.36	$ 0.27
Weighted average shares used in computation			
Basic...	26,628	25,294	21,979
Diluted...	27,987	27,122	24,414

The fair value of each option grant for the years ended December 31, 2003, 2002, and 2001, 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, 2003	2002	2001
Expected life (years)	7	10	10
Interest rate	3.73%	4.17%	5.13%
Volatility	65.27%	61.62%	62.56%
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 the earlier of 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 PLANS

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 contributions at least equal to the minimum funding provisions of employee benefit and tax laws, but

usually no more than the maximum tax deductible contribution allowed. We do not expect to make a contribution in 2004. Plan assets consist primarily of equity and fixed income securities. The following tables set forth significant information about the plans, the reconciliation of the benefit obligation, plan assets, and funded status for the pension plans.

	AT DECEMBER 31, 2003	2002
	(IN THOUSANDS)	
RECONCILIATION OF THE CHANGE IN PROJECTED BENEFIT OBLIGATION		
Beginning projected benefit obligation	$4,833	$3,305
Service cost	415	291
Interest cost	322	263
Amendments	42	--
Actuarial loss	633	1,179
Benefits paid	(213)	(205)
Ending projected benefit obligation	$6,032	$4,833

RECONCILIATION OF THE CHANGE IN PLAN ASSETS		
Beginning market value	$4,506	$2,766
Actual return on plan assets	846	(324)
Employer contributions	850	2,269
Benefit payments	(213)	(205)
Ending market value	$5,989	$4,506
FUNDED STATUS AND AMOUNTS RECOGNIZED IN THE BALANCE SHEET		
Excess of assets over projected benefit obligation	$ (43)	$ (327)
Unrecognized net actuarial loss	2,458	2,473
Unrecognized prior service costs	39	--
Adjusted net prepaid benefit cost recognized	$2,454	$2,146
ACCUMULATED BENEFIT OBLIGATION	$5,077	$4,169
ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATIONS		
Discount rate	6.00%	6.50%
Rate of compensation increase	3.00%	3.00%

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

	FOR YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
COMPONENTS OF NET PERIODIC PENSION COST			
Service cost	$415	$291	$151
Interest cost on projected benefit obligation	322	263	221
Expected return on plan assets	(352)	(219)	(239)
Recognized net actuarial loss	154	62	--
Amortization of prior service costs	3	--	--
Net periodic pension cost	$542	$397	$133
ASSUMPTIONS USED TO DETERMINE NET PERIODIC PENSION COSTS			
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%

To estimate the expected long-term rate of return on pension plan assets, we consider the current and expected asset allocations, as well as historical returns on equities and debt securities.

The accumulated benefit obligation represents the present value of the benefits earned to the measurement date, with benefits computed based on current compensation levels. The projected benefit obligation is the accumulated benefit obligation increased to reflect expected future compensation.

Remington's aggregate projected benefit obligation at December 31, 2003, was $5.4 million and the aggregate fair value of plan assets was $5.2 million. On December 31, 2003, Remington had a prepaid benefit cost of $2.1 million. CKB Petroleum's aggregate projected benefit obligation at December 31, 2003, was $666,000 and the aggregate fair value of plan assets was $806,000. On December 31, 2003, CKB Petroleum had a prepaid benefit cost of $398,000.

PLANS ASSET ALLOCATION (PLANS' ASSETS ARE HELD IN TRUST.)

	AT DECEMBER 31, 2003	AT DECEMBER 31, 2002
ASSET CATEGORY		
Equity securities	63.6%	54.0%
Debt securities	20.6%	16.5%
Money funds	15.8%	29.5%
Total	100.0%	100.0%

Money fund balances were disproportionately high at each year end because we made large contributions to the pension trusts during the last few days of each year. These funds were allocated to equity and debt securities and utilized for regular distributions to retirees during the early part of the next year. See the discussion of our investment policy below.

Plan fiduciaries set investment policies, strategies, and guidelines for the pension trusts. These include

- Achieve a long-term average annual rate of return of at least 8%.

- Asset allocations ranging from 75% equities and 25% debt securities to 25% equities and 75% debt securities. Recommended long-term average allocation is 60% equities and 40% debt securities.

- Permissible investments include publicly-traded common and preferred stocks, convertible bonds, fixed income securities, guaranteed investment contracts, and money market funds. Transactions are not permitted in futures contracts or options.

- Plan assets will be well diversified.

Plan fiduciaries have appointed an investment advisor and asset managers. A Plan Administration Committee, presently comprising three company executive officers, meets with the investment advisor at least quarterly to review overall investment performance, investment manager performance, current asset category allocations, recommended asset category allocations for the coming quarter, and sources of liquidity for distributions to retirees for the coming quarter.

During the latter part of 2002 the committee, with the assistance of the investment advisor, set the target allocation at 75% equities and 25% debt securities and has maintained that target allocation continuously since then.

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 each of the years ended December 31, 2003 and 2002 we amortized $1.3 million and $1.4 million, respectively, to stock based compensation expense. The remaining unearned compensation expense will be amortized over the next two 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.

A summary of the stock grant as of December 31, 2003, 2002, and 2001 and changes during the years ending on those dates is presented below:

	AT DECEMBER 31,					
	2003		2002		2001	
	SHARES	WEIGHTED AVERAGE PRICE	SHARES	WEIGHTED AVERAGE PRICE	SHARES	WEIGHTED AVERAGE PRICE
Outstanding at beginning of period	447,192	$ 12.16	662,592	$ 12.16	662,592	$ 12.16
Grants	--	$ --	--	$ --	--	$ --
Issued	(173,228)	$ 12.16	(212,761)	$ 12.16	--	$ --
Forfeited	(14,328)	$ 12.16	(2,639)	$ 12.16	--	$ --
Outstanding at end of period	259,636	$ 12.16	(447,192)	$ 12.16	662,592	$ 12.16

REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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 them.

NOTE 8 -- INCOME TAXES

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

	FOR YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Current income tax expense (benefit)	$ 175	$ --	$ (12)
Deferred income tax expense	23,443	6,095	3,600
Total income tax expense	$23,618	$6,095	$3,588

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,		
	2003	2002	2001
	(IN THOUSANDS)		
Federal income tax expense at statutory rate	$23,290	$6,095	$4,175
Net adjustment to valuation allowance	--	--	(575)
State income tax expense and other	328	--	(12)
Total income tax expense	$23,618	$6,095	$3,588

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

AT DECEMBER 31,

	2003	2002
	(IN THOUSANDS)	
Deferred tax liabilities		
Oil and gas properties	$(35,429)	$(15,671)
Total deferred tax liabilities	(35,429)	(15,671)
Deferred tax assets		
Federal net operating loss carryforwards	4,130	5,275
Federal alternative minimum tax credit carryforwards	479	416
Accrued liabilities	1,980	2,745
Other assets	89	43
Total deferred tax assets	6,678	8,479
Valuation allowance	--	--
Net deferred tax assets	6,678	8,479
Net deferred tax liability	$(28,751)	$ (7,192)

The unused federal income tax operating loss carry-forward of $11.8 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,

	2003		2002		2001	
	OIL BBLS	GAS MCF	OIL BBLS	GAS MCF	OIL BBLS	GAS MCF
			(IN THOUSANDS)			
Beginning of period	13,114	124,967	13,865	111,920	10,370	88,650
Revisions of previous estimates	(363)	(5,754)	(596)	(4,271)	1,221	(1,414)
Extensions, discoveries and other	337	42,676	1,678	39,603	3,507	45,951
Reserves purchased	306	4,692	--	--	--	--
Reserves sold	--	--	(104)	(4,837)	--	--
Production	(1,775)	(24,149)	(1,729)	(17,448)	(1,233)	(21,267)
End of period	11,619	142,432	13,114	124,967	13,865	111,920
Proved developed reserves	7,071	76,475	7,977	71,481	6,690	60,756

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,		
	2003	2002	2001
West Texas Intermediate (per barrel)	$29.25	$28.00	$16.75
Gulf Coast Spot Market (per MMbtu)	$ 5.97	$ 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. Future income tax expense was determined by applying the current statutory 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.

	AT DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Oil and gas revenues	$1,206,775	$ 946,813	$ 542,193
Production costs	(165,733)	(150,084)	(107,586)
Development costs	(140,175)	(116,944)	(84,561)
Income tax expense	(223,929)	(166,864)	(53,020)
Net cash flow	676,938	512,921	297,026
10% annual discount	(190,642)	(161,879)	(97,043)
Standardized measure of discounted future net cash flows	$ 486,296	$ 351,042	$ 199,983

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(1) Based on Netherland, Sewell & Associates' reserve report for January 1, 2004, we estimate that the amount of capital required to convert proved undeveloped reserves to proved developed reserves will be $107.1 million of the $140.2 million of future development costs, including $28.2 million in 2004, $30.6 million in 2005 and $15.4 million in 2006. Our actual expenditures may differ from these estimates. Capital expenditures incurred to develop proved undeveloped reserves were $28.4 million in 2003, $28.5 million in 2002 and $19.3 million in 2001.

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

	AT DECEMBER 31		
	2003	2002	2001
	(IN THOUSANDS)		
Standardized measure of discounted cash flows at beginning of year	$351,042	$199,983	$ 458,649
Sales and transfers of oil and gas produced, net of production costs and net profits expense	(161,670)	(84,231)	(98,274)
Net changes in prices and production costs	134,883	198,760	(486,774)
Net changes in estimated development costs	(13,169)	(4,229)	70
Net changes in estimated net profits expense	--	--	10,510
Net changes in income tax expense	(47,324)	(79,090)	172,708
Extensions, discoveries and improved recovery less related costs	141,970	123,755	89,048
Proved oil and gas reserves purchased	13,998	--	--
Proved oil and gas reserves sold	--	(6,997)	--
Previously estimated development costs incurred during the year	28,477	22,893	32,687
Revisions of previous quantity estimates	(34,006)	(24,244)	13,356
Other changes	36,991	(15,556)	(37,861)
Accretion of discount	35,104	19,998	45,864

Standardized measure of discounted future net cash flows end of year	$486,296	$351,042	$ 199,983

REMINGTON OIL AND GAS CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

NOTE 10 -- QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	FOR YEARS ENDING DECEMBER 31,	
	2003	2002
	(IN THOUSANDS, EXCEPT PER SHARE DATA)	
FIRST QUARTER		
Net revenues(1)	$42,304	$19,375
Net income	$11,687	$ 258
Basic net income per share	$ 0.44	$ 0.01
Diluted net income per share	$ 0.42	$ 0.01
SECOND QUARTER		
Net revenues(1)	$45,780	$27,406
Net income(2)	$12,264	$ 6,252
Basic net income per share	$ 0.46	$ 0.24
Diluted net income per share	$ 0.44	$ 0.22
THIRD QUARTER		
Net revenues(1)	$46,867	$25,937
Net income	$10,068	$ 3,967
Basic net income per share	$ 0.38	$ 0.15
Diluted net income per share	$ 0.36	$ 0.14
FOURTH QUARTER		
Net revenues(1)	$47,627	$27,663
Net income (loss)	$ 8,904	$ 855
Basic net income per share	$ 0.33	$ 0.03
Diluted net income per share	$ 0.32	$ 0.03

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

(2) Net income during the second quarter of 2002 included 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 years prior to 2002 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 fiscal year 2001 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.

ITEM 9A. 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.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

We have adopted a code of ethics (our "Code of Business Conduct and Ethics" previously filed with the Commission and accessible on our website) that applies to all directors and employees including our Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer.

The remainder of the information required by Item 10, Directors and Executive Officers of the Registrant, will be included in our definitive proxy statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11, Executive Compensation, will be included in our definitive proxy statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

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

The information required by Item 12, Security Ownership of Certain Beneficial Owners and Management, will be included in our definitive proxy statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The information required by Item 13, Certain Relationships and Related Transactions, will be included in our definitive proxy statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of

1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

The information required by Item 14, Principal Accountant Fees and Services, will be included in our definitive proxy statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

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, 2003 and 2002

(iii) Consolidated Statements of Income for years ended December 31, 2003, 2002 and 2001

(iv) Consolidated Statement of Stockholders' Equity for years ended December 31, 2003, 2002 and 2001

(v) Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001

(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.

3. Exhibits

EXHIBIT NUMBER	EXHIBIT
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.
10.5+++	Amendment Number Four 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.

EXHIBIT NUMBER	EXHIBIT
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.
10.13**	Form of Contingent Stock Grant Agreement -- Directors.
10.14**	Form of Contingent Stock Grant Agreement -- Employees.
10.15**	Form of Amendment to Contingent Stock Grant Agreement -- Directors.
10.16**	Form of Amendment to Contingent Stock Grant Agreement -- Employees.
14.##	Code of Business Conduct and Ethics.
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, 2000 filed with the Commission on March 16, 2001.

++ 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 and effective 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 and effective 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.

Incorporated by reference to the Company's Form 10-Q (file number 1-1156) for the fiscal quarter ended June 30, 2003, filed with the Commission on August 11, 2003.

+++ Filed herewith.

(b) Reports on Form 8-K:

On October 29, 2003 we filed a form 8-K reporting third quarter earnings press release under Item 12. Results of Operations and Financial Condition.

On December 19, 2003, we filed a form 8-K reporting under Item 5. Other Events, our press release containing information about our $200 million shelf registration being declared effective.

SIGNATURES

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

REMINGTON OIL AND GAS CORPORATION

By: /s/ JAMES A. WATT

James A. Watt
President and Chief Executive Officer

Date: March 11, 2004

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

DIRECTORS:

/s/ JOHN E. GOBLE, JR.	/s/ WILLIAM E. GREENWOOD	/s/ RO
John E. Goble, Jr. Director	William E. Greenwood Director	Robe
/s/ DAVID E. PRENG		/s/ A
David E. Preng Director	Thomas W. Rollins Director	Ala
/s/ JAMES A. WATT		
James A. Watt Director		

OFFICERS:

/s/ JAMES A. WATT	/s/ J. BURKE ASHER	/s/ ED
James A. Watt President and Chief Executive Officer	J. Burke Asher Vice President/Finance (Principal Financial Officer)	Edwa Vice President Accou

Date: March 11, 2004

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