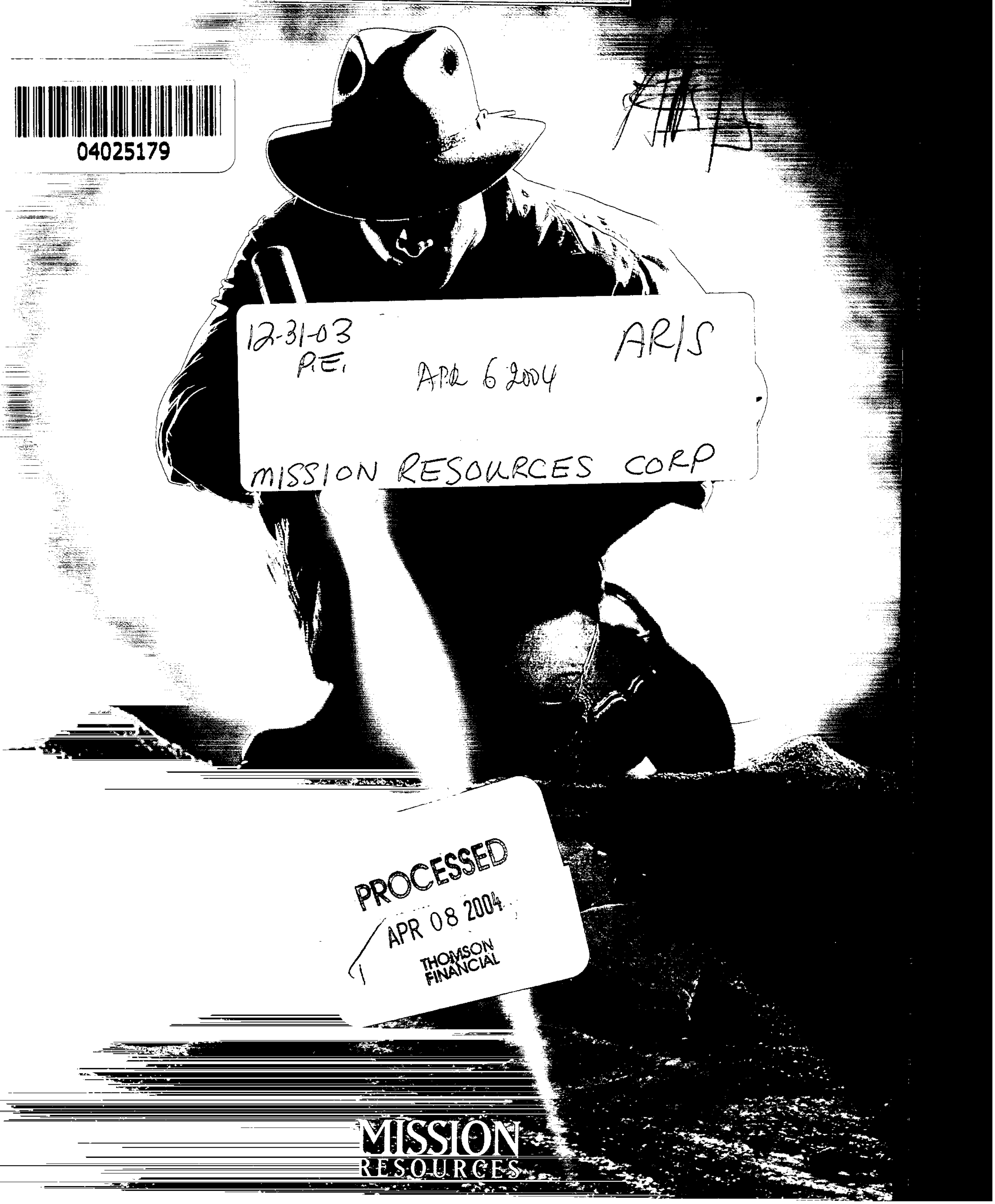
FOCUSING *our* ENERGY



MISSION
RESOURCES

Welcome to Mission Resources, a revitalized exploration and production company that is establishing a presence in the natural gas and oil industry. During the last 18 months, we've transformed this company from the inside out. As a part of this transformation, we now have a new identity, one that better reflects our focus on growing Mission Resources through the establishment of clear goals, concentrating on our core strengths, and executing disciplined strategies and tactics. We are truly focusing our energy on delivering shareholder value with integrity and transparency.

FOCUS

Late in the summer of 2002, we set a straightforward, but aggressive goal – execute a successful company-wide recovery and establish a new direction for Mission Resources, one that is defined by performance and accountability. Early in 2003 steps were taken to lower costs, reduce debt and strengthen the company's financial position. But we spent 2003 focusing our energy on more than just these goals.

We've successfully moved toward a more reliable and cost-effective production mix. We've also sharpened our focus geographically in our core areas of the Permian Basin, the Texas and Louisiana Gulf Coast, and South Texas.

As the letter from our Chairman on the following pages indicates, our efforts are delivering results. Our business is markedly stronger. Our financial condition is substantially sounder. Our growth prospects are considerably brighter. We're looking forward to 2004.

(In millions of dollars except as otherwise indicated)

FINANCIAL REVIEW	2003	2002	2001	2000	1999
Total revenues	124.0	105.5	142.1	119.3	73.4
Net income (loss)[1]	2.4	(38.5)	(30.9)	32.2	8.8
Earnings (loss) per common share — diluted [2]	0.10	(1.63)	(1.54)	2.27	0.63
Discretionary cash flow	22.8	23.5	44.7	62.6	30.8
Total assets	354.3	342.4	447.8	221.5	171.8
Long-term debt (excluding unamortized premium)	197.4	225.0	260.0	125.5	130.0
Shareholders' equity	74.9	65.4	110.2	57.0	23.3
Weighted average number of common shares outstanding — diluted	24.7	23.8	20.2	14.2	13.9
OPERATIONAL REVIEW					
Capital expenditures, including acquisitions [3]	35.4	21.6	278.1	91.5	57.6
Total production (BCFE)	22.9	33.1	38.0	34.8	31.4
Average daily oil production (MBO)	5.7	8.6	8.9	5.9	5.0
Average daily gas production (MMCF)	28.3	38.7	50.9	59.5	56.1
Average daily total production (MMCFE)	62.5	90.3	104.3	94.9	86.1
Proved oil reserves (MMBO)	13.7	22.6	39.5	17.5	14.7
Proved gas reserves (BCF)	95.5	93.5	166.4	84.7	142.5
Total proved reserves (BCFE)	177.9	229.1	403.7	189.7	230.7
SEC PV-10 value (pre-tax)	350.5	326.9	365.4	546.0	209.0

(1) Results for 2002 include the effects of a non-cash, after-tax impairment of goodwill for $16.7 million and results for 2001 include the effects of a non-cash after-tax impairment of proved properties of $13.5 million.
(2) Due to a potential antidilutive effect in loss periods, common shares outstanding were used for periods with a loss.
(3) Acquisitions include cash and non-cash consideration, reduced for the impact of deferred taxes.

(Amount in millions)

	2003	2002	2001	2000	1999
NET CASH PROVIDED BY OPERATING ACTIVITIES:	$ 18.9	$ 7.2	$ 40.4	$ 60.1	$ 38.6
Change in assets and liabilities	4.0	13.7	4.3	2.5	(7.8)
Loss on disposal of non-operating assets	(0.1)	—	—	—	—
Loss on asset sales	—	2.6	—	—	—
DISCRETIONARY CASH FLOW:	**$22.8**	**$23.5**	**$44.7**	**$62.6**	**$30.8**

ABBREVIATIONS

BCF	Billion cubic feet of gas	MBO	Thousand barrels of crude oil	MMCF	Million cubic feet of gas
BCFE	Billion cubic feet of gas equivalent	MMBO	Million barrels of crude oil	MMCFE	Million cubic feet of gas equivalent

*NOTE – Management believes that discretionary cash flow is relevant and useful information that is commonly used by analysts, investors and other interested parties in the oil and gas industry. Accordingly, we are disclosing this information to permit a more comprehensive analysis of our operating performance and liquidity, and as an additional measure of Mission's ability to meet its future requirements for debt service, capital expenditures and working capital. Discretionary cash flow should not be considered in isolation or as a substitute for net income, cash flow provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles ("GAAP") or as a measure of our profitability or liquidity. Discretionary cash flow excludes components that are significant in understanding and assessing our results of operations and cash flows. In addition, discretionary cash flow is not a term defined by GAAP and, as a result, our measure of discretionary cash flow might not be comparable to similarly titled measures used by other companies.

MESSAGE *from the* CHAIRMAN

2003 was a year of intense effort to strengthen and stabilize Mission and position it for growth. This included not only reducing debt and strengthening our balance sheet, it also involved a concentrated focus on our base business. Early in the year, we established key goals to define success of our efforts.

ROBERT L. CAVNAR
Chairman, President and Chief Executive Officer

I am pleased that we have made substantial progress on all fronts.

Dear Shareholders: To date, we have reduced our debt by $57 million while increasing our flexibility through a series of debt repurchase and debt-for-equity swaps. We believe the reduction in our interest expense, together with lower unit operating costs and increased operational efficiencies, will continue to improve our discretionary cash flow going forward.

While financially strengthening the company has been critically important, we have also succeeded in refocusing our business — finding, developing and producing natural gas and crude oil. We have established natural gas as our primary product. In so doing, we have shifted our geographic focus to onshore sites in the Permian Basin and select areas along the Texas and Louisiana Gulf Coast, enhanced our in-house exploration program, and continued to develop and exploit our existing reserve base.

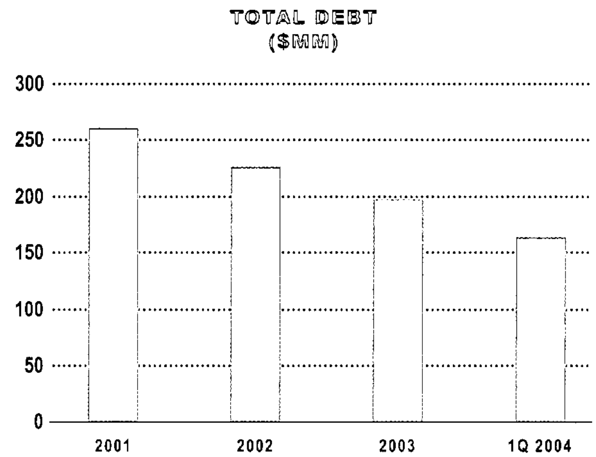
Our 2003 activities did not go unnoticed. By February 14, 2003, our stock had declined to an all-time low of $.22 per share; it has consistently traded above $2.00 per share throughout the first quarter of 2004. A year ago, our senior subordinated notes were about 60% of par; today, they are trading at essentially par. These increases in value are a direct result of our efforts during 2003.

FOCUSING *our* ENERGY

DE-LEVERING OUR BALANCE SHEET

Recovery of Mission's financial stability and value continues to be a top priority. One of our primary goals last year was to reduce our debt to a more manageable level. In March 2003, we completed a debt repurchase of $97.6 million of our 10 7/8% senior subordinated notes for approximately $72 million, which was financed by an amended and restated senior secured credit facility. This transaction reduced our debt by $17 million and added $5 million of cash for capital expenditures. This was an important first step in strengthening our balance sheet and getting our capital program moving. We followed this transaction in December 2003 with a debt-for-equity swap of $10 million of our 10 7/8% senior subordinated notes for 4.5 million shares of the company's common stock. By the end of 2003, Mission reflected a net reduction in long-term debt of approximately $28.0 million, or 12% of total debt outstanding.

In early 2004, we completed two additional debt-for-equity swaps, acquiring $30 million of our 10 7/8% senior subordinated notes for 12.25 million shares of Mission common stock. Clearly, we've made significant strides toward de-levering our balance sheet, but there is still more work to do. In order to further reduce our interest expense, we are currently negotiating a new senior credit facility. Our debt-for-equity swaps have strengthened our ability to be successful in these negotiations.

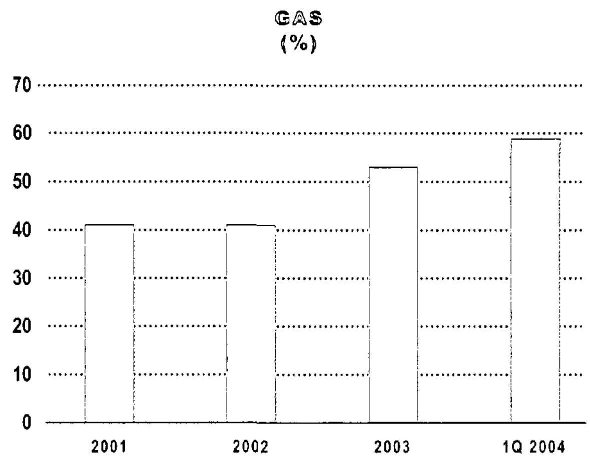


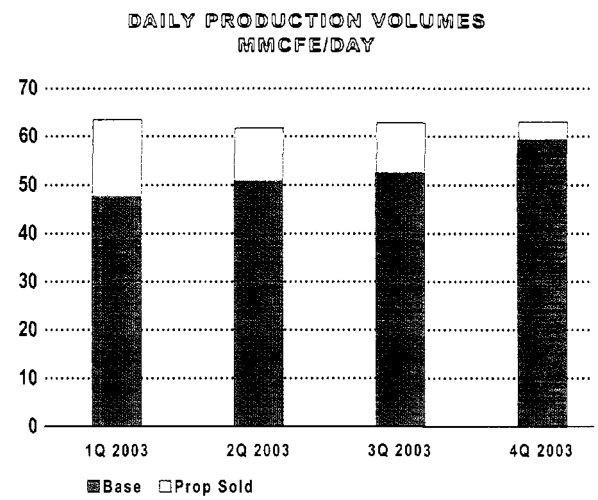
LOWERING UNIT OPERATING EXPENSE

In early 2003 another key goal we established was to lower unit operating expense. Since then, we have sold high-cost assets, redeployed the funds received to acquire low-cost gas properties, pursued primarily gas reserves in our drilling program, and continued our efforts to reduce costs in our remaining portfolio. Cost control remains a critical part of our focus. As we realize the benefit of lower average operating costs as well as reductions in interest expense, we believe our increased discretionary cash flow will provide us with even greater flexibility to further reduce our debt.

NATURAL GAS FOCUS

We remain focused on establishing natural gas as our primary product. Our activities, including the review and evaluation of current properties and the selection of prospects to explore and develop, have been successful





in moving us toward a 70% gas, 30% oil production mix. In fact, by the end of the fourth quarter of 2003, our production mix changed to 53% natural gas and after the January Jalmat acquisition to 59%, from 41% in the fourth quarter of 2002. We anticipate making additional progress in 2004 toward our goal of 70% natural gas production.

DISCIPLINED DRILLING AND ASSET OPTIMIZATION

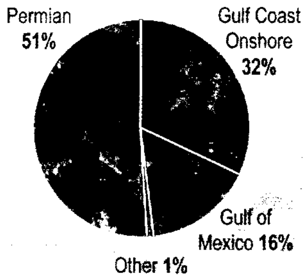
We have also sharpened our focus geographically to the Permian Basin (West Texas and Southeast New Mexico), along the Texas and Louisiana Gulf Coast, South Texas and in the Gulf of Mexico. Our in-house technical staff of geologists, geophysicists and engineers are experienced in these geographic basins and utilize the latest in exploration, drilling and completion technology.

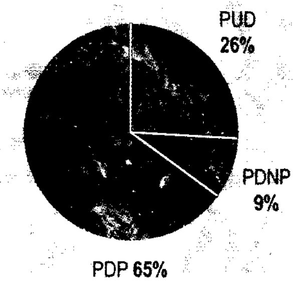
Our efforts to maximize the value of our core properties involves the evaluation of many of our mature assets where we are focused on increasing production, cash flow and reserves. In some instances, we have chosen to divest ourselves of high operating cost properties. In October 2003, we closed on the sale of our East Texas assets for net cash proceeds of approximately $19 million and in November, we closed on the sale of our Raccoon Bend assets for net proceeds of $5 million.

As previously mentioned, we recently redeployed funds from these property sales to acquire an approximately 80% operated working interest in the Jalmat Field in Lea County, New Mexico for $26.6 million in cash. This acquisition of natural gas properties further drives the company toward our production mix goal. The enhancement opportunities inherent within the Jalmat Field will help drive down unit operating costs as our development and upgrade program gets underway.

RESERVES

As of the end of 2003 our proved reserves as estimated by Netherland, Sewell & Associates, Inc. were 178 BCFE with a PV-10 (using SEC pricing) value of approximately $350 million. We replaced 100% of our 2003 production through reserve discoveries and extensions and 118% replacement of production from all sources (discoveries, extensions, purchases and upward revisions), exclusive of our asset sales. Our all source reserve replacement cost





PUD Proved Undeveloped
PDP Proved Developed Producing
PDNP Proved Developed Non-Producing

(As of December 31, 2003)

for 2003 was $1.27 per MCFE. With the January 2004 acquisition of the Jalmat Field, we added an additional 26 BCFE of proved reserves and our PV-10 value increased to approximately $393 million.

NEW IMAGE

We have decided, as a part of the recovery of Mission's strength and stability, that it is appropriate to adopt a new image, which reflects our approach and "puts a new face" on the company. We believe our new corporate image is unique and we are excited to bring it to you for the first time in this annual report. The inside cover of this report describes the new image as well as our theme of "Focusing our Energy" to bring value to our stakeholders, our partners and our employees.

DELIVERING VALUE

Clearly, we have achieved a lot in 2003 on the exploration, development, acquisition and financial fronts. But our job is far from complete.

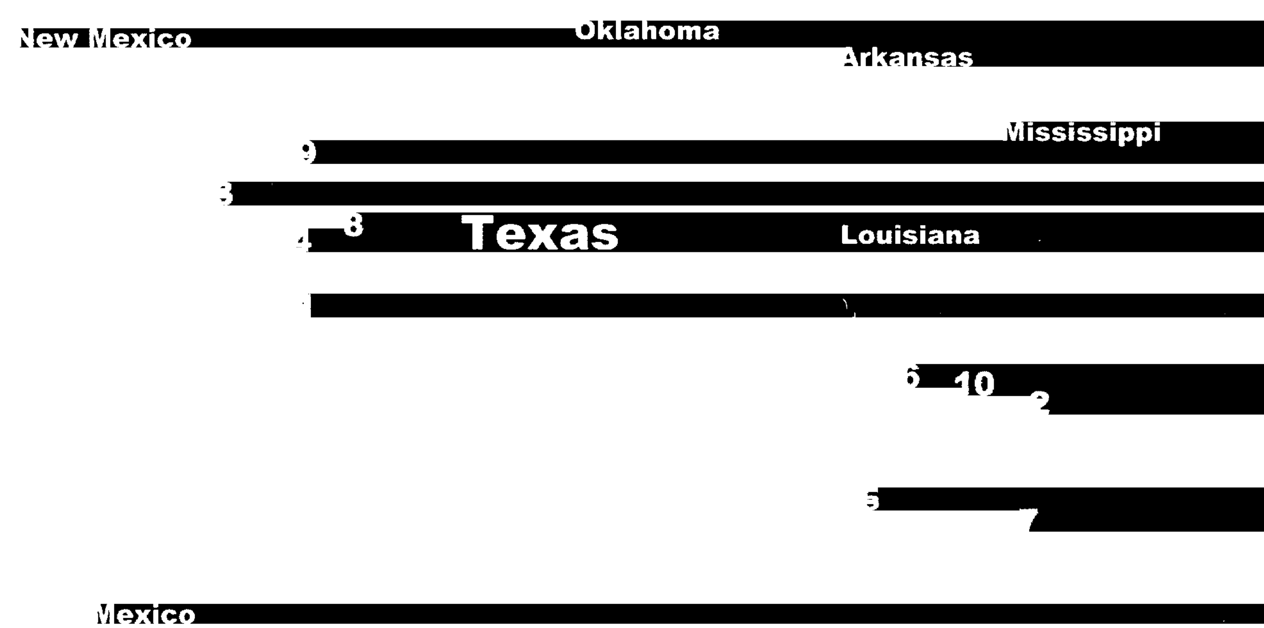
In 2004 and beyond, we'll continue to focus on the set of objectives that guided us through 2003, including: Strengthening our balance sheet by reducing leverage and driving down unit operating costs. Completing our transition toward a 70% natural gas, 30% oil production mix. Achieving a balance between long and short-life reserves. Expanding our in-house exploration and evaluation capability. Sustaining our geographic focus in the Permian Basin, the Texas and Louisiana Gulf Coast, and South Texas and concentrating exploration efforts onshore in these regions. Protecting cash flows by hedging a percentage of proved producing production. Placing the highest value on corporate governance, board independence, transparency and operating with integrity in all business dealings. Continuing to conduct our business safely with the utmost respect for the environment in which we operate.

Everyone at Mission Resources is dedicated to executing our business plan aggressively, efficiently and with integrity. We look forward to keeping you informed of our progress throughout the year, and we thank you for your continued support of the Company.

Sincerely,

ROBERT L. CAVNAR
Chairman, President and Chief Executive Officer

AREAS of OPERATION



TOP TEN PROPERTIES

[illegible] Waddell Ranch
[illegible] S. Bayou Boeuf
[illegible] Jalmat
[illegible] EXL
[illegible] High Island A-552
[illegible] North Leroy
[illegible] South Marsh Island 142
[illegible] Goldsmith
[illegible] Wasson
[illegible] Reddell

TOTAL OPERATIONS

204 BCFE(1) total proved reserves

$393 MM(1)(2) total pre-tax PV-10%

PERMIAN BASIN

[illegible] BCFE reserves (57%)

$173 MM PV-10% (44%)

GULF COAST ONSHORE

[illegible] BCFE reserves (28%)

[illegible]148 MM PV-10% (37%)

GULF OF MEXICO OFFSHORE

[illegible] BCFE reserves (14%)

[illegible] MM PV-10% (17%)

OTHER(3)

[illegible] BCFE reserves (1%)

[illegible] MM PV-10% (2%)

(1) Pro forma for the Jalmat acquisition.
(2) PV-10 value based on December 31, 2003, NYMEX spot prices of $5.97 per MMBTU for natural gas and $32.47 per BBL for oil.
(3) Includes properties in Oklahoma, Oregon and Wyoming.

SENIOR MANAGEMENT (Pictured above from left to right.)

Joseph G. Nicknish
Senior Vice President - Operations and Engineering

John (Jack) L. Eells
Senior Vice President - Exploration and Geoscience

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Richard W. Piacenti
Executive Vice President and Chief Financial Officer

Marshall L. Munsell
Senior Vice President - Land and Land Administration

BOARD OF DIRECTORS (Pictured below from left to right.)

Robert R. Rooney
Governance / Compensation Committee Chairman
Audit Committee Member

Herbert C. Williamson III
Audit Committee Member
Governance / Compensation Committee Member

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Joseph N. Jaggers
Governance / Compensation Committee Member

David A.B. Brown
Audit Committee Chairman

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

Form 10-K

(Mark One)

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

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**

Commission File Number 0-9498

Mission Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**76-0437769** *(I.R.S. Employer Identification No.)*
1331 Lamar, Suite 1455, Houston, Texas *(Address of principal executive offices)*	**77010-3039** *(Zip Code)*

Registrant's telephone number, including area code: (713) 495-3000

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

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, $0.01 par value
Series A Preferred Stock Purchase Rights

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

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant at June 30, 2003 was approximately $49,030,863.

As of March 5, 2004, the number of outstanding shares of the registrant's common stock was 34,267,636.

Documents Incorporated by Reference:

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

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

Annual Report on Form 10-K
For the Year Ended December 31, 2003

TABLE OF CONTENTS

PART I

Forward Looking Statements

This annual report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). All statements other than statements of historical fact are forward-looking statements. Forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our estimate of the sufficiency of existing capital sources, our highly leveraged capital structure, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, and the operating hazards attendant to the oil and gas business. Although we believe that in making such forward-looking statements our expectations are based upon reasonable assumptions, such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. We cannot assure you that the assumptions upon which these statements are based will prove to have been correct.

When used in this Form 10-K, the words "expect", "anticipate", "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussions and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest in our common stock, you should be aware that the occurrence of any of the events described in "Management's Discussions and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

As used in this annual report, the words "we", "our", "us", "Mission" and the "Company" refer to Mission Resources Corporation, its predecessors and subsidiaries, except as otherwise specified.

Terms specific to the oil and gas industry may be used in this Form 10-K. For explanation of technical terms, refer to the "Glossary of Oil and Gas Terms" at the end of this Form 10-K.

Items 1. & 2. *Business and Properties*

General

Mission Resources Corporation is an independent oil and natural gas exploration and production company headquartered in Houston, Texas. We drill for, acquire, develop and produce natural gas and crude oil primarily, in the Permian Basin (in West Texas and Southeast New Mexico), along the Texas and Louisiana Gulf Coast and in both the state and federal waters of the Gulf of Mexico. At December 31, 2003, our estimated net proved reserves, using constant prices which were in effect at such date, were 85.1 billion cubic feet ("BCF") of natural gas, 10.4 billion cubic feet equivalents ("BCFE") of natural gas liquids ("NGLs") and 13.7 million barrels ("MMBBL") of oil, for total reserves of approximately 178 BCFE. Approximately 54% of the estimated net proved reserves were natural gas or NGLs, and approximately 75% of the reserves were developed at December 31, 2003. On January 30, 2004, we closed the $26.6 million acquisition of the Jalmat field in the Permian Basin. This acquisition adds approximately 26 BCFE of proved reserves and brings our percentage of natural gas and NGLs to 59%.

Our Business Strategy and Competitive Strengths

During 2002, our new management team began to reduce leverage, refinance indebtedness, focus on natural gas, and expand our oil and gas reserves through exploration and development and targeted acquisitions. We intend to build upon the progress we have made in these areas by executing our business strategy to:

- *Reduce leverage and increase operational flexibility.* Since March 2003, through a combination of debt repurchases and equity for debt exchanges, we have eliminated over $43 million of indebtedness, reduced our debt as a percentage of book capitalization from 78% to 67% and reduced annual interest expense by approximately $3.7 million. We intend to further reduce leverage as we move toward our long term goal of debt as a percentage of book capital of 50%.

- *Establish natural gas as our primary product.* We have made progress toward our goal of a 70% natural gas to 30% oil production mix, and we are continuing to focus on the exploration and development of natural gas reserves in our core geographic areas. After the Jalmat acquisition in January 2004, natural gas represents 59% of our total production, up from 41% in the fourth quarter of 2002.

- *Reduce our unit operating expense.* In order to lower unit operating expenses, we sold certain assets which had high operating costs, including our offshore California, East Texas and Raccoon Bend properties. These asset sales, combined with new production from our drilling programs, helped to reduce our operating expenses per MCFE from $1.42 in the fourth quarter of 2002 to $1.24 in fourth quarter of 2003. In January 2004, we redeployed funds from asset sales to acquire our interest in the Jalmat field in the Permian Basin. This field, with its ongoing operating expenses of approximately $0.70 per MCFE will help further reduce our unit operating expenses. We expect to make further reductions in unit costs, as reflected in our 2004 operating expense guidance of between $1.15 to $1.25 per MCFE.

- *Manage our portfolio of assets.* We are actively developing our assets to maximize their value and conducting field studies to find additional opportunities to enhance the performance of our properties. Our goal is to balance long life properties with high rate, high decline properties. Our strategy is to limit our capital expenditures to no more than our discretionary cash flow. In 2003, we spent $34.4 million drilling 48 wells, of which 42 were successful. In addition to acquiring the Jalmat field, we plan to spend $32-34 million in 2004 on capital expenditures. In order to protect our cash flows, to the extent possible, we intend to hedge forward 12 months up to 75% of our proved developed production, and up to 50% of the following 12 months' proved developed production.

- *Utilize our exploration team to develop prospects and maintain low finding and development costs.* During 2003, we assembled an exploration team of geophysicists and geologists with expertise in the industry and in our core areas. Utilizing our existing 3-D seismic library and newly acquired data sets, this team is developing natural gas prospects, primarily in the Gulf Coast onshore area. This team is skilled in using seismic reprocessing, new seismic surveys, reservoir simulation and sophisticated drilling and completion techniques. In 2003, our efforts reduced our finding and development costs to $1.27 per MCFE, and in 2004 we intend to continue our efforts to find reserves on a cost effective basis.

Our Oil and Gas Properties

Reserves

Our estimated net proved oil and gas reserves at December 31, 2003 were approximately 178 BCFE. We replaced production through reserve additions and extensions and also had positive reserve revisions. As part of our strategy to reduce unit costs and increase our percentage of production from natural gas, we sold 55 BCFE of high operating cost reserves, primarily oil, in 2003. Set forth below is a reconciliation of our yearend 2003 reserves, as compared to our yearend 2002 reserves, based upon the evaluation of reserves by Netherland, Sewell & Associates, Inc. The reserves were calculated using SEC yearend pricing:

	BCFE
Proved reserves at beginning of year	229.1
Revisions of previous estimates	3.6
Extensions and discoveries	23.0
Production	(22.9)
Sales of reserves in-place	(55.4)
Purchase of reserves in-place	0.5
Proved reserves at end of year	177.9

In January 2004, we acquired the Jalmat field for $26.6 million. This acquisition added approximately 26 BCFE to the amount of our reserves shown above.

In general, estimates of economically recoverable oil and natural gas reserves and of the future net cash flows therefrom are based upon a number of factors, such as historical production from the properties, assumptions concerning future oil and natural gas prices, future operating costs and the assumed effects of regulation by governmental agencies, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. Estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net cash flows expected therefrom, prepared by different engineers or by the same engineers at different times, may vary. Mission's actual production, revenues, severance and excise taxes and development and operating expenditures with respect to its reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

In accordance with applicable requirements of the Securities and Exchange Commission, the discounted future net cash flows from estimated proved reserves are based on prices and costs as of the date of the estimate unless prices or costs subsequent to that date are contractually determined. Actual future prices and costs may be materially higher or lower than prices or costs as of the date of the estimate. Actual future net cash flows also will be affected by factors such as actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs. See "Risk Factors" for a discussion of the uncertainties inherent in preparing reserve estimates.

Production

The following table sets forth our net production and net proved reserves as of and for the year ended December 31, 2003 by geographic area.

	Net Production			Estimated Net Proved Reserves			Discounted Future Net Cash Flows(1) ($000's)
Area	Oil (MBBLS)	Gas & NGL (MMCFE)	Gas Equivalent (MMCFE)	Oil (MBBLS)	Gas & NGL (MMCFE)	Gas Equivalent (MMCFE)	
Permian Basin	778	2,160	6,830	10,128	29,910	90,680	$130,802
Gulf Coast	608	4,048	7,696	2,387	42,718	57,043	147,813
Gulf of Mexico	315	3,302	5,189	1,202	20,149	27,361	65,271
Other	396	804	3,181	7	2,732	2,771	6,570
	2,097	10,314	22,896	13,724	95,509	177,855	$350,456

(1) In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows are based on prices and costs as of the date of the estimate. The average prices on December 31, 2003 for natural gas and oil used in our estimate were $5.97 per MMBTU and $32.47 per BBL.

The acquisition of the Jalmat field in January 2004 added approximately $42 million to the amount of the December 31, 2003 discounted future net cash flows that are shown above.

Data relating to production volumes, production costs and oil and gas reserve information are contained in Note 16 of the Notes to Consolidated Financial Statements

The following table provides summary statistics about our most significant properties by geographic area as of December 31, 2003.

	Percent Gas/Oil	Average Reserve to Production Ratio in Years
Permian Basin Area	33/67	13
Waddell Ranch Field	21/79	17
TXL North Unit	30/70	13
Wasson Field	7/93	11
Goldsmith Field	37/63	9
Gulf Coast Area	75/25	8
North Leroy Field	96/4	12
Reddell Field	66/34	9
South Bayou Boeuf Field	72/28	—(1)
Gulf of Mexico Area	74/26	5
High Island Block A-553	91/9	—(1)
South Marsh Island Block 142	53/47	8
Other(2)	99/1	3

(1) Because most reserves are undeveloped at yearend and 2003 production was low, this measure is not useful for these individual fields.

(2) Includes isolated property interests in Wyoming, Oregon, and Oklahoma.

Permian Basin Area

Waddell Field

Waddell Field is a large, mature property consisting of 1,600 producing wells that produces oil and gas from various Permian age formations ranging in depth from 3,000 to 5,000 feet. The property, which covers over 75,000 acres, is located in the Permian Basin in Crane County, Texas. Burlington Resources is the operator and Mission's interest is approximately 10%. A portion of the field is under waterflood. The field is under continuous development predominantly by means of well recompletions and workovers.

TXL North Unit

The TXL North Unit is an active waterflood unit that consists of 225 wells and produces from the Tubb formation at a depth of approximately 5,500 feet. Anadarko Petroleum Corporation operates the property, located in the Permian Basin in Ector County, Texas, and Mission holds an approximate 20% working interest and 25% net revenue interest. A 10-acre infill development program was initiated in 2003, with the successful drilling of twenty wells, and continues with additional drilling which began in early 2004.

Wasson Field

Mission holds an approximate 36% working interest in the Brahaney Unit, located in the Permian Basin in Yoakum County, Texas. Apache Corporation operates this waterflood unit that consists of 95 producing wells and produces from the San Andres formation at a depth of 5,500 feet. Production has increased significantly in past few years as a result of a successful infill drilling program. In 2003, ten wells were drilled and the development drilling program continues.

Goldsmith Field

The Goldsmith Field consists primarily of the CA Goldsmith Unit, operated by Chevron-Texaco, and is located in the Permian Basin in Ector County, Texas. Mission holds a 25% working and net revenue interest in this property. The field consists of 250 producing wells with production primarily from the Clearfork and Devonian formations at depths ranging from 5,500 to 8,000 feet.

Jalmat Field (2004 Acquisition)

The January 2004 acquisition of the Jalmat field, added approximately 26 BCFE to our proved reserves. Mission is the operator of this field and our average working interest is approximately 80%. This field produces primarily from the Yates and 7-Rivers formations at depths ranging from 3,000 to 4,200 feet. Gas production from the Yates and 7-Rivers has a high heating content and is processed at a nearby plant to yield significant volumes of natural gas liquids. Numerous behind pipe recompletions and infill drilling potential exist in both the Yates and 7-Rivers formations. Additionally, the deeper Queen formation may have waterflood potential.

Gulf Coast Area

North Leroy Field

North Leroy is a natural gas field located in Vermilion Parish, Louisiana and produces from multiple Frio-age reservoirs at depths ranging from 11,500 to 13,000 feet. Mission operates one of the three producing wells with an average working interest of 81%. One well was drilled in 2003 and several recompletion candidates have already been identified.

Reddell Field

Reddell Field is a natural gas field located in Evangeline Parish, Louisiana that produces from the Upper, Middle and Lower Wilcox at depths ranging from 10,000 to 13,000 feet. Burlington Resources operates the field consisting of 21 producing wells. In 2003, one well was drilled and three wells were successfully recompleted to the upper Wilcox. Mission holds a 15% working interest in the field, in which additional development opportunities exist.

South Bayou Boeuf

South Bayou Boeuf Field is located in LaFourche Parish, Louisiana and produces from various Miocene-age formations at depths ranging from 10,000 to 12,500 feet. Mission operates the field and holds an average working interest of 96% in the six producing wells. Reserve upside exists in development drilling updip to productive wells.

Gulf of Mexico Area

High Island Block A-553

Mission operates this property located offshore Louisiana in federal waters (water depth of 260 feet). The field produces from Pleistocene and Pliocene formations ranging from 5,000 to 12,000 feet. Production and reserves are primarily natural gas with liquid condensate. In 2003, Mission acquired an additional minor interest in the property, increasing its working interest to approximately 37%. The block contains one platform and six wells. Recompletion and drilling opportunities exist on this block.

South Marsh Island Block 142

Located in federal waters (water depth of 230 feet), offshore Louisiana, South Marsh Island Block 142 produces oil and natural gas from Pleistocene and Pliocene formations at depths ranging from 3,000 to 7,000 feet. Mission holds an approximate 31% working interest and Hunt Petroleum, Inc. is the operator of this property. The field contains two platforms and 16 wells, including two successful development wells drilled in 2003. There are additional development drilling and recompletion opportunities on this block.

Historical Drilling Activity

Our principal drilling activities during the last three years were focused on properties in the Permian Basin, along the Texas and Louisiana Gulf Coast and in the Gulf of Mexico. The following tables set forth the results of drilling activity for the last three years:

Exploratory Wells

	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2001	2	6	8	0.92	1.13	2.05
2002	4	1	5	1.66	0.07	1.73
2003	3	2	5	0.64	0.26	0.90

Development Wells

	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2001	48	7	55	14.24	5.13	19.37
2002	29	3	32	10.03	1.11	11.14
2003	39	4	43	11.41	1.74	13.15

One well was in progress as of December 31, 2003.

Our Interest in Productive Wells

The following table sets forth the number of productive oil and gas wells in which we own interests as of December 31, 2003. Productive wells are defined as producing wells and wells capable of production. Gross wells are the number of wells in which we own a working interest. The number of net wells is the sum of the fractional ownership of working interests that we own directly in gross wells. Therefore, the number of net wells does not represent a number of actual, physical wells, but rather quantifies the actual total working interests we hold in all wells. We compute the number of net wells by adding together the percentage of interests we hold in all our gross wells.

	Gross	Net
Oil Wells:		
Permian Basin	942	118.2
Gulf Coast	81	44.3
Gulf of Mexico	75	13.2
Other	17	0.4
Total Oil Wells	1,115	176.1
Gas Wells:		
Permian Basin	719	146.0
Gulf Coast	49	19.9
Gulf of Mexico	218	33.7
Other	50	10.6
Total Gas Wells	1,036	210.2
Total Wells	2,151	386.3

Our Acreage

The following table sets forth information concerning our developed and undeveloped oil and gas acreage as of December 31, 2003. Undeveloped acreage consists of those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. The number of gross acres in the following table refers to the total number of acres in which we own a working interest. The number of net acres is the sum of the fractional ownership of working interests that we own in the gross acres. All of our developed and undeveloped acreage is located in the United States and its territorial waters.

	Gross	Net
Developed Acreage:		
Permian Basin	100,224	15,001
Gulf Coast	36,861	8,039
Gulf of Mexico	176,440	34,718
Other	29,739	3,199
Total Developed Acreage	343,264	60,957
Undeveloped Acreage:		
Permian Basin	19,126	4,195
Gulf Coast	15,668	9,528
Gulf of Mexico	52,785	17,935
Other	72,819	31,485
Total Undeveloped Acreage	160,398	63,143
Total Acreage	503,662	124,100

The primary terms of our oil and natural gas leases expire at various dates. Some of our undeveloped acreage is "held by production", which means that these leases are active as long as we produce oil or natural gas from the acreage. Upon ceasing production, these leases will expire.

Our Principal Markets and Customers

We sell our natural gas and oil production under fixed or floating market price contracts. Our revenues, profitability, cash flow and future growth depend substantially on prevailing prices for natural gas and oil. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions and actual or threatened acts of war, terrorism or hostilities in oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions.

Decreases in the prices of natural gas and oil could adversely affect the carrying value of proved reserves and revenues, profitability and cash flow. Although we are not currently experiencing any curtailment of natural gas or oil production, market, economic and regulatory factors may in the future materially affect our ability to sell natural gas or oil production.

In 2003, sales of oil and natural gas to Shell Trading (US) Company accounted for approximately 21.5% of our oil and gas revenues, and no other purchaser accounted for more than 10% of our oil and gas revenues. If we were to lose any one (including Shell Trading (US) Company) of our oil and natural gas purchasers, the loss could temporarily delay production and sale of our oil and natural gas in the particular purchaser's service area; however, we believe that we could quickly identify a substitute purchaser. In 2002, no single customer accounted for more than 10% of our oil and gas revenues. During 2002, several large wholesale purchasers of natural gas experienced significant downgrades in their credit ratings. As a result, many of these companies have either reduced their level of natural gas purchases or have discontinued their purchases of natural gas. Although we do not believe that we have been significantly impacted by these changes, the loss of these large natural gas purchasers could have a detrimental effect on the natural gas market in general and on our ability to find purchasers for our natural gas. When we deem it necessary or prudent we require letters of credit, parent company guarantees or other forms of credit enhancement from our purchasers.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these hedging arrangements also limit the benefits we would realize if prices increase. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counter parties we believe represent minimal credit risks. We cannot assure you that these trading counter parties will not become credit risks in the future. For further information concerning our hedging transactions, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Our Competition

The oil and natural gas industry is highly competitive. We compete with both independent operators and major oil companies in all areas of our operations, including acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have greater financial and technical resources and substantially larger staffs than we do. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling or other activities and has caused significant cost increases. We are unable to predict when, or if, such shortages may again occur or how they would affect exploration and development plans.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. Many large oil companies have been actively marketing some of their existing producing properties for sale to independent producers. We cannot assure you that we will be able to compete for these properties successfully.

Applicable Laws and Regulations

United States Regulations

Sales and Transportation of Gas

Historically, the sale or resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and the regulations promulgated hereunder by the Federal Energy Regulatory Commission ("FERC"). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining NGA and NGPA price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

Mission's sales of natural gas are affected by the availability, terms and cost of transportation. The rates, terms and conditions applicable to the interstate transportation of gas by pipelines are regulated by the FERC under the NGA, as well as under section 311 of the NGPA. Since 1985, the FERC has implemented regulations intended to increase competition within the gas industry by making gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

The Outer Continental Shelf Lands Act ("OCSLA") requires that all pipelines operating on or across the Outer Continental Shelf ("OCS") provide open-access, non-discriminatory service. Although the FERC has opted not to impose the regulations of Order No. 509, in which the FERC implemented the OCSLA, on gatherers and other non-jurisdictional entities, the FERC has retained the authority to exercise jurisdiction over those entities if necessary to permit non-discriminatory access to service on the OCS. FERC also issued Order No. 639, requiring that virtually all non-proprietary pipeline transporters of natural gas on the OCS report information on their affiliations, rates and conditions of service. Among the FERC's stated purposes in issuing such rules was the desire to provide shippers on the OCS with greater assurance of open-access services on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. A federal district court recently determined that FERC has exceeded its statutory authority in promulgating Order Nos. 639 and 639-A, and the court permanently enjoined FERC from enforcing the orders. FERC has appealed the district court's decision.

FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service ratemaking methodology to establish the rates interstate pipelines may charge for their services. The final rule revised FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

Sales and Transportation of Oil

Sales of oil and condensate can be made at market prices and are not subject at this time to price controls. The price received from the sale of these products will be affected by the cost of transporting the products to market. FERC regulations govern the rates that may be charged by oil pipelines by use of an indexing system for setting transportation rate ceilings. In certain circumstances, rules permit oil pipelines to establish rates using traditional cost of service and other methods of rate making.

Legislative Proposals

In the past, Congress has been very active in the area of gas regulation. In addition, there are legislative proposals pending in the state legislatures of various states, which, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

Federal, State or Indian Leases

To the extent that we conduct operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or, in the case our OCS leases in federal waters, Minerals Management Service ("MMS") or other appropriate federal or state agencies. Mission's OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the OCSLA that are subject to interpretation and change by the MMS. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds are not currently material, but could become substantial if we expand our areas of operations. There is no assurance that bonds or other surety can be obtained in all cases. We are currently in compliance with the bonding requirements of the MMS. Any such suspension or termination could materially adversely affect Mission's financial condition and results of operations.

On March 15, 2000, the MMS issued a final rule effective June 2000, which amended its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because Mission sells most of its production at spot market prices and, therefore, pays royalties on production from federal leases based on spot prices, it is not anticipated that this final rule will have a material impact on Mission.

The Mineral Leasing Act of 1920 (the "Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that our common stock will be acquired by citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and gas, including:

- requirements for obtaining drilling permits,
- the method of developing new fields,
- the spacing and operation of wells,
- the prevention of waste of oil and gas resources, and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Mission owns certain natural gas pipeline facilities that we believe meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation.

Environmental Regulations

General

Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Our activities with respect to exploration, drilling and production from wells, natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing gas and other products, are subject to stringent environmental regulation by state and federal authorities including the Environmental Protection Agency ("EPA"). Risks are inherent in oil and gas exploration and production operations, and we can give no assurance that significant costs and liabilities will not be incurred in connection with environmental compliance issues. Neither can we predict what effect future regulation or legislation, enforcement policies issued thereunder, and claims for damages to property, employees, other persons and the environment resulting from our operations could have.

Solid and Hazardous Waste

Mission currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we utilized operating and waste disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we currently own or lease or on or under properties that we once owned or leased. In addition, many of these properties are or have been operated by third parties over whom we had no control as to their treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under recent laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

Mission generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under RCRA and state analogs ("Hazardous Waste"). Furthermore, it is possible that certain wastes generated by our oil and gas operations that are currently exempt from treatment as Hazardous Waste may in the future be designated as Hazardous Waste under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Superfund

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on potentially responsible parties ("PRPs") with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). PRPs include the current and certain past owners and operators of a facility where there is or has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances released at the site. CERCLA also authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substances, in the course of its operations, Mission has generated and will generate wastes that may be a CERCLA Hazardous Substance. We may also own or operate sites on which Hazardous Substances have been released. Mission may be responsible under CERCLA for all or part of the costs of investigation, remediation, and natural resource damages at sites where Hazardous Substances have been released. We have not been named a PRP under CERCLA nor do we know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties.

Clean Water Act

The Clean Water Act ("CWA") imposes restrictions and strict controls regarding the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined and including wetlands. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into waters of the United States. The CWA and OPA require facilities that store or otherwise handle oil in excess of specified quantities to prepare and implement spill prevention, control and countermeasure plans and facility response plans relating to possible discharges of oil to surface waters. The CWA provides for civil, criminal and administrative penalties for violations, including unauthorized discharges of pollutants and of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In the event of an unauthorized discharge of wastes, Mission may be liable for penalties and costs.

Oil Pollution Act

The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of CWA, imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in United States waters and adjoining shorelines. A "responsible party" includes the owner or operator of a facility or vessel that is a source of an oil discharge or poses the substantial threat of discharge, or the lessee or permittee of the area in which a discharging facility covered by OPA is located. OPA assigns joint and several liability, without regard to fault, to each responsible party for oil removal costs and a variety of public and private damages. Few defenses exist to the liability imposed by OPA. In the event of an oil discharge or substantial threat of discharge, Mission may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in the event of a potential spill. The OPA requires owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal OCS waters, with higher amounts, up to $150 million based upon worst case oil spill discharge volume calculations. We believe that we currently have established adequate proof of financial responsibility for our offshore facilities.

Air Emissions

Mission's operations are subject to local, state and federal regulations for the control of emissions of air pollution. Federal and State laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent requirements including additional permits. Particularly stringent requirements may be imposed on major sources located in non-attainment areas designated as not meeting National Ambient Air Quality Standards established by the EPA. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies may bring lawsuits for civil or criminal penalties or require us to forego construction, modification or operation of certain air emission sources.

Coastal Coordination

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act ("CZMA") was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

In Texas, the Texas Legislature enacted the Coastal Coordination Act in 1991 ("CCA"). The CCA provides for the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. The act establishes the Texas Coastal Management Program ("CMP"). The CMP is limited to the nineteen counties that border the Gulf of Mexico and its tidal bays. The act provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may impact agency permitting and review activities and add an additional layer of review to certain activities that we undertake.

In Louisiana, state legislation enacted in 1978 established the Louisiana Coastal Zone Management Program ("LCZMP") to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities in the coastal zone, even if the activity only partially infringes on the coastal zone. The Coastal Management Division of Louisiana's Department of Natural Resources administers the coastal use permit program which applies in coastal areas of 18 of Louisiana's 64 parishes. Activities requiring such a permit include, among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated time constraints for our projects.

OSHA and other Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the Environmental Protection Agency community right-to-know regulations under Title III of CERCLA and similar state statutes require Mission to organize and/or disclose information about hazardous materials used or produced in its operations. We believe that we are in substantial compliance with the applicable requirements.

In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or private prosecution.

Title to Our Properties

When we acquire developed properties, we conduct a title investigation. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct a title review of local mineral records. We do conduct title investigations and often obtain a title opinion before we begin drilling operations. We believe that the methods we use for investigating title prior to acquiring any property are consistent with standards generally accepted in the oil and gas industry and that our practices are adequately designed to enable us to acquire good title to properties. However, some title risks cannot be avoided, despite the use of accepted practices.

Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties;
- overriding royalties;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect oil and gas producing property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating net revenue interests and in estimating the size and value of our proved reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for the kind of properties that we own. Up to 90% of our properties are pledged as collateral under our credit facility.

Our Employees

At December 31, 2003, Mission had 85 full time employees. In addition to the services of our full time employees, we utilize the services of independent contractors to perform certain services. We believe that our relationships with our employees are satisfactory. None of our employees is covered by a collective bargaining agreement.

In the beginning of 2003, we were party to a Master Service Agreement ("MSA") dated October 1, 1999, and two service contracts under the terms of which Torch Energy Advisors, Inc. ("Torch") operated our oil and gas properties and marketed our oil and gas production. We terminated the service contracts effective February 1, 2003 and April 1, 2003, respectively. We hired additional qualified employees, including many of the operations staff from Torch, to handle those functions. The MSA was terminated on April 1, 2003 because all service contracts had terminated as of that date.

Our Facilities

Our corporate office occupies approximately 29,000 square feet of leased office space at 1331 Lamar, Suite 1455, Houston, Texas 77010. We also have leased offices in Giddings, Texas and Lafayette, Louisiana from which our employees supervise local oil and gas operations.

Our Available Information

Mission's Internet website can be found at www.mrcorp.com. Mission makes available free of charge, or through the "Investor Relations" section of our Internet website at www.mrcorp.com, access to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed pursuant to Section 13(a) of 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonable practicable after such material is filed or furnished to the Securities and Exchange Commission.

Risk Factors

Risks Related to Financing Our Business

If we are not able to fund our planned capital expenditures, our cash flow from operations will decrease.

We make, and will need to continue to make, substantial capital expenditures for the development, exploration, acquisition and production of oil and gas reserves. Our capital expenditures were $35.4 million, $21.4 million, and $72.2 million for the years ended December 31, 2003, 2002 and 2001, respectively. Historically, we have financed these expenditures primarily with cash flow from operations, the issuance of bonds or bank credit facility borrowings, the issuance of our common stock, or the sale of oil and gas properties. Our current primary sources of liquidity are cash flow from operations, credit facility borrowings, and sales of oil and gas properties. We have budgeted total capital expenditures in 2004 of $32.0 to $34.0 million, however, we intend to increase or decrease this amount depending upon cash flow generated by operations. Natural gas and oil prices, the timing of our drilling program and drilling results have a significant impact on the cash flows available for capital expenditures and our ability to borrow and raise additional capital. Lower prices and/or lower production may decrease revenues and cash flows, thus reducing the amount of financial resources available to meet our capital requirements.

We believe that cash flows from operating activities combined with our ability to control the timing of substantially all of our future exploration and development requirements will provide us with the flexibility and liquidity to meet our planned capital requirements for 2004. If revenues or our borrowing base decrease for any of the reasons discussed above, we may have limited ability to expend the capital necessary to undertake our 2004 exploration and development program. We cannot assure you that additional debt or equity financing or cash generated by operations or oil and gas property sales will be available to meet these requirements.

We have a highly leveraged capital structure, which limits our financial flexibility.

We have a highly leveraged capital structure due to our outstanding 10⅞% senior subordinated notes due 2007 and our $80.0 million term loan facility. Although we reduced the outstanding balance of our 10⅞% subordinated notes due 2007 to $117.4 million in 2003, our capital structure remains highly leveraged, which limits our financial flexibility. Our level of indebtedness has several important effects on our future operations, including:

- a substantial portion of our cash flow from operations, approximately $22 million in 2004, must be dedicated to the payment of interest on our indebtedness and will not be available for other purposes;
- covenants contained in our debt obligations, including those in our $80.0 million term loan facility, require us to meet certain financial tests, and other restrictions limit our ability to borrow additional funds or dispose of assets and may affect our flexibility in planning for, and reacting to, changes in our business, including possible acquisition activities; and
- our ability to obtain financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes may be impaired.

Our ability to meet our debt service obligations and to reduce our total indebtedness will be dependent upon future performance, which will be subject to general economic conditions and to financial, business and other factors affecting our operations, many of which are beyond our control. We cannot assure you that our future performance will not be adversely affected by such economic conditions and financial, business and other factors. We intend to take additional actions in 2004 to improve our financial condition. Among the alternatives that we may consider are

- a refinancing of the remaining 10⅞% subordinated notes;
- a new credit facility;
- a merger with or an acquisition by another company;
- the acquisition by Mission of another company or assets;
- other secured and unsecured debt financings; and
- the issuance of equity securities or other debt securities for cash or properties or in exchange for the notes.

Some of these alternatives would require approval of our stockholders, and all of them will require the approval of other parties to the transaction. We cannot assure you that we will be successful in completing any of these possible transactions.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of cashless collars or swap contracts and are placed with major trading counter parties we believe represent minimum credit risks. We cannot assure you that these trading counter parties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the prices for natural gas and oil. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in natural gas and oil prices.

Risks Related to Our Business and Industry

We may be unable to acquire or develop additional reserves.

As is generally the case in the oil and natural gas industry, our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number of properties for sale. If we are unable to conduct successful development activities or acquire properties containing proved reserves, our total proved reserves will generally decline as a result of production. Also, our production will generally decline. If our reserves and production decline then the amount we are able to borrow under our credit facility will also decline. We cannot assure you that we will be able to locate additional reserves, that we will drill economically productive wells or that we will acquire properties containing proved reserves.

Market uncertainty and a variety of additional factors beyond our control can create large price fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, which could result in low commodity prices.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include:

- weather conditions in the United States;
- the condition of the United States economy;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation;
- political stability in the Middle East and elsewhere;
- the foreign supply of oil and gas;
- the price of foreign imports; and
- the availability of alternate fuel sources.

Any substantial and extended decline in the price of oil or gas would have an adverse effect on the carrying value of our proved reserves, our borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows. Lower prices may also reduce the amount of oil and natural gas that we can produce economically and require us to record ceiling test write-downs.

Volatile oil and gas prices make it difficult to estimate the value of producing properties in connection with acquisitions and often cause disruption in the market for oil and gas producing properties as buyers and sellers have difficulty agreeing on transaction values. Price volatility also makes it difficult to budget for and project the return on acquisitions, development and exploration projects. To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices.

We may not be able to market all or obtain favorable prices for the oil or gas we produce.

Our ability to market oil and gas from our wells depends upon numerous domestic and international factors beyond our control, including

- the extent of domestic production and imports of oil and gas;
- the proximity of gas production to gas pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effects of inclement weather;
- state, federal and international regulation of oil and gas production; and
- federal regulation of gas sold or transported in interstate commerce.

We cannot assure you that we will be able to market all of the oil or gas we produce or that we can obtain favorable prices for the oil and gas we produce.

You should not place undue reliance on reserve information because reserve information represents estimates.

This document contains estimates of our oil and gas reserves and the future net cash flows attributable to those reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows attributable to such reserves, including factors beyond our control and the control of reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of

- the available data;
- assumptions regarding future oil and gas prices and expenditures for future development and exploitation activities; and
- engineering and geological interpretation and judgment.

Additionally, reserves and future cash flows may be subject to material downward or upward revisions based upon production history, development and exploitation activities and prices of oil and gas. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and estimates in this document. In calculating reserves on a gas equivalent basis, oil was converted to gas equivalent at the ratio of six MCF of gas to one BBL of oil. While this ratio approximates the energy equivalency of gas to oil on a BTU basis, it may not represent the relative prices received by us on the sale of our oil and gas production.

You should not assume that the present value of future net revenues referred to in this document and the information incorporated by reference is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

Lower oil and natural gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves.

Competition in our industry is intense, and many of our competitors have greater financial, technological and other resources than we have.

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors may be able to pay more for desirable leases, or evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploration activities and has caused significant price increases. In the event of such shortages, larger competitors may have an advantage in obtaining drilling rigs and equipment. We are unable to predict when, or if, such shortages may again occur or how they would affect our exploration and development program. Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete successfully. Many large oil companies have been actively marketing some of their existing producing properties for sale to independent producers. We cannot assure you that we will be successful in acquiring any of these properties.

We may have claims asserted against us to plug and abandon wells and restore the surface.

In most instances, oil and gas lessees are required to plug and abandon wells that have no further utility and to restore the surface. We are often required to obtain bonds to secure these obligations. In instances where we purchase or sell oil and gas properties, the parties to the transaction routinely include an agreement as to who will be responsible for plugging and abandoning any wells on the property and for restoring the surface. In those cases, we may be required to obtain new bonds or may release old bonds regarding our plugging and abandonment exposure based on the terms of the purchase and sale agreement. However, if a subsequent owner or party to the purchase and sale agreement defaults on its obligations to plug and abandon a well or restore the surface and otherwise fails to obtain a bond to secure the obligation, the landowner or in some cases the applicable state or federal regulatory authority, may assert that we are obligated to plug the well as a prior owner of the property. In other instances, we may receive a demand as a current owner of the property to plug and abandon certain wells in the field and to restore the surface although we are still actively developing the field.

Mission has been notified of such claims from certain parties and landowners and from the State of Louisiana. For the year 2003 we have recognized costs of approximately $252,000 for the abandonment and cleanup of the Bayou Ferblanc field and approximately $379,000 for the proposed settlement of abandonment issues at the West Lake Ponchartrain field. Approximately $161,000 in costs related to Bayou Ferblanc were recognized in 2002. At this time, it is not possible to determine the amount of potential exposure that we may have for any other claims. Although there can be no assurances, we do not presently believe these claims would have a material adverse effect on our financial condition or operations.

In 1993 and 1996 we entered into agreements with surety companies and, at that time, affiliated companies Torch and Nuevo Energy Company ("Nuevo") whereby the surety companies agreed to issue such bonds to Mission, Torch and Nuevo. As part of these agreements, Mission, Torch, and Nuevo agreed to be jointly and severally liable to the surety company for any liabilities arising under any bonds issued to Mission, Torch and Nuevo. The amount of bonds presently issued to Torch and Nuevo pursuant to these agreements is approximately $0.4 million and $34.8 million, respectively. We have notified the sureties that we will not be responsible for any new bonds issued to Torch or Nuevo. However, the sureties are permitted under these agreements to seek reimbursement from us, as well as from Torch and Nuevo, if the surety makes any payments under the bonds previously issued to Torch and Nuevo.

Compliance with environmental and other government regulations is costly and could negatively impact production.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of material regulations applicable to us, see "Regulation — Federal Regulations," "— State Regulations" and "— Environmental Regulations." These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

The Oil Pollution Act of 1990 imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act of 1990, could have a material adverse impact on us.

Risks Relating to Our Ongoing Operations

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, including, but not limited to, Robert L. Cavnar, our Chairman, Chief Executive Officer and President, Richard W. Piacenti, our Executive Vice President and Chief Financial Officer, John L. Eells, our Senior Vice President — Exploration and Geoscience, Joseph G. Nicknish, our Senior Vice President — Operations and Engineering, and Marshall L. Munsell, our Senior Vice President — Land and Land Administration. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our operations.

The oil and gas business involves many operating risks that can cause substantial losses.

Our operations are subject to risks inherent in the oil and gas industry, such as

- unexpected drilling conditions, such as blowouts, cratering and explosions;
- uncontrollable flows of oil, gas or well fluids;
- equipment failures, fires, earthquakes, hurricanes or accidents; and
- pollution and other environmental risks.

These risks could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Moreover, a portion of our operations are offshore and therefore are subject to a variety of operating risks that occur in the marine environment, such as hurricanes or other adverse weather conditions, and to more extensive governmental regulation, including regulations that may, in certain circumstances, impose strict liability for pollution damage, and to interruption or termination of operations by governmental authorities based on environmental or other considerations.

We cannot control the development of the properties we own but do not operate.

As of December 31, 2003, we do not operate wells that represent approximately 65% of the present value of estimated future net revenues of our proved reserves. As a result, the success and timing of our drilling and development activities on those properties depend upon a number of factors outside our control, including

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties, we may not be able to increase our production or offset normal production declines.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

Our operations could result in a liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden environmental damages, but do not believe that insurance coverage for all environmental damages that occur over time is available at a reasonable cost. Moreover, we do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or the loss of substantial portions of our properties in the event of certain environmental damages.

Risks Related to Our Common Stock Outstanding

Our stock price is volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may be highly volatile. Factors such as announcements concerning changes in prices of oil and natural gas, the success of our exploration and development drilling program, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

The lack of trading could adversely affect the prevailing market for our common stock.

Historically, there has been limited trading volume with respect to our common stock. In addition, we cannot assure you that there will continue to be a trading market or that any securities research analysts will provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.

If we raise additional funds by issuing shares of common stock, or securities convertible into or exchangeable or exercisable for common stock, or if we enter into additional arrangements to issue common stock in exchange for outstanding debt obligations, further dilution to our existing stockholders will result. New investors could also have rights superior to existing stockholders. Pursuant to our stock incentive plans, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon exercise or vesting of any outstanding stock awards.

The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.

The issuance of a significant number of shares of common stock upon the exercise of stock options, or the availability for sale or sale of a substantial number of the shares of common stock eligible for future sale under effective registration statements, Rule 144 or otherwise, could adversely affect the market price of the common stock. We have reserved approximately 4.7 million shares of common stock for issuance under outstanding options. These shares of common stock are registered for resale on currently effective registration statements. We registered the resale of 4.5 million shares of common stock that were issued in exchange for $10 million of our 10⅞% senior subordinated notes due 2007. We are also obligated to register the resale of the 6.25 million shares of common stock issued in exchange for $15 million of our notes in February 2004.

We have not and do not expect in the near future to pay dividends.

We have never declared or paid any cash dividends on our common stock and have no intention to do so in the near future. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indentures executed in connection with our 10⅞% senior subordinated notes due 2007. In addition, our credit facility contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Our certificate of incorporation, bylaws, rights plan and Delaware law have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of our certificate of incorporation, bylaws and rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and on stockholder action by written consent. We are also subject to Section 203 of the Delaware General Corporation Law, which generally prohibits a Delaware corporation from engaging in any of a broad range of business combinations with an interested stockholder for a period of three years following the date on which the stockholder became an interested stockholder. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

In September 1997, our board of directors adopted a rights plan, pursuant to which uncertificated stock purchase rights were distributed to our stockholders at a rate of one right for each share of common stock held of record as of September 26, 1997. The rights plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price.

Item 3. *Legal Proceedings*

Mission is involved in litigation relating to claims arising of its operations in the normal course of business, including workmen's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on Mission's business or financial position.

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*

Mission's common stock is traded on The Nasdaq National Market (Symbol: MSSN).

The following table sets forth the range of the high and low sales prices, as reported by Nasdaq for our common stock for the periods indicated.

	Sales Price	
	High	Low
Quarter Ended:		
March 31, 2002	$3.57	$2.60
June 30, 2002	$3.05	$1.35
September 30, 2002	$1.52	$0.48
December 31, 2002	$0.80	$0.28
March 31, 2003	$0.47	$0.22
June 30, 2003	$1.88	$0.25
September 30, 2003	$2.45	$1.30
December 31, 2003	$2.99	$1.62

We have not paid dividends on our common stock and do not anticipate paying cash dividends in the immediate future as we contemplate that our cash flows will be used for continued growth of our operations. In addition, certain covenants contained in our financing arrangements restrict the payment of dividends (see Management's Discussion and Analysis of Financial Condition and Results of Operations — Financing Activities and Note 8 of the Notes to Consolidated Financial Statements). There were approximately 1,310 stockholders of record as of February 18, 2004.

On December 17, 2003, we entered into a purchase and sale agreement with FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series providing for the issuance by us of 4.5 million shares of our common stock in exchange for the surrender by the Franklin entities of $10.0 million aggregate principal amount of our 10⅞% senior subordinated notes due 2007. Accrued interest on the notes to the date of the agreement will be paid on April 1, 2004, the regularly scheduled interest payment date for the notes, or upon the occurrence of certain other events. The shares of common stock issued in the transaction were exempt from registration pursuant to Section 3(a)(9) of the Securities Act of 1933, as amended, as they were exchanged with our existing security holders exclusively and no commission or remuneration was paid or given directly or indirectly for the exchange.

Item 6. ***Selected Financial Data***

The following selected financial data with respect to Mission should be read in conjunction with the Consolidated Financial Statements and supplementary information included in Item 8 (amounts in thousands, except per share data).

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Gas revenues	$ 46,443	$ 42,953	$ 60,924	$ 66,953	$ 44,276
Oil revenues	52,914	69,926	72,311	45,300	23,988
Gas plant revenues	—	—	4,456	6,070	3,830
Gain on extinguishment of debt	23,476	—	—	—	—
Interest and other income (loss)	1,141	(7,415)	4,386	957	1,335
Total revenues	123,974	105,464	142,077	119,280	73,429
Lease operating expense	32,728	43,222	44,773	24,553	18,702
Taxes other than income	8,251	9,246	6,656	6,273	3,072
Transportation costs	349	834	73	270	316
Gas plant expenses	—	—	2,118	2,677	2,366
Asset retirement obligation accretion expense	1,263	—	—	—	—
Depreciation, depletion and amortization	38,501	43,291	45,106	32,654	23,863
Impairment expense	—	16,679	27,971	—	—
Disposition of hedges	—	—	—	8,671	—
Uncollectible gas revenues	—	—	2,189	—	—
Loss on sale of assets	—	2,645	11,600	—	—
General and administrative expenses	10,856	12,758	15,160	8,821	7,606
Interest expense	25,565	26,853	23,664	15,375	11,845
Provision for income tax (benefit)	2,358	(11,580)	(9,055)	(12,222)	(3,154)
Total expenses	119,871	143,948	170,255	87,072	64,616
Cumulative effect of a change in accounting method, net of deferred taxes	1,736	—	2,767	—	—
Net income (loss)	$ 2,367	$(38,484)	$(30,945)	$ 32,208	$ 8,813
Earnings (loss) per common share	$ 0.10	$ (1.63)	$ (1.54)	$ 2.32	$ 0.64
Earnings (loss) per common share — diluted	$ 0.10	$ (1.63)	$ (1.54)	$ 2.27	$ 0.63
Working capital	$ 13,201	$ 952	$ 105	$ 7,212	$ 3,770
Long-term debt, net of current maturities	$198,496	$226,431	$261,695	$125,450	$130,000
Stockholders' equity	$ 74,940	$ 65,377	$110,240	$ 56,960	$ 23,314
Total assets	$354,250	$342,404	$447,764	$221,545	$171,761

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

Mission is an independent oil and natural gas exploration and production company. We drill for, acquire, develop and produce natural gas and crude oil. Our property portfolio is comprised of long-lived, low-risk assets, like those in the Permian Basin, and multi-reservoir, high-productivity assets found along the Gulf Coast and in the Gulf of Mexico. Our operational focus remains on efficient, well managed upstream natural gas and crude oil exploration and production. We will continue to pursue complementary acquisitions when the appropriate opportunities present themselves. Mission's results of operations for the year 2003 included the following financial and operational highlights.

- Reduced long-term debt by $27.9 million and annual interest expense by $2 million
- Reduced operating expenses per MCFE from $1.42 in the fourth quarter of 2002 to $1.24 in the fourth quarter of 2003.
- Established a new revolving credit facility, making available $12.5 million for short-term borrowings.
- Sold several high-cost oil properties, making available approximately $25 million for re-investment in gas properties.
- Drilled 3 successful exploratory and 39 successful developmental wells that increased reserves enough to fully replace 2003 production.
- Moved in-house previously outsourced functions of operations, marketing, accounting, treasury, land administration, human resources and risk management. As a result of this infrastructure shift, we were able to achieve greater levels of efficiency and responsiveness.
- Completed building our exploration team of experienced geophysicists and geologists with significant expertise in the industry and our core areas.
- Hedged approximately 75% of 2004 proved developed producing reserves at a weighted average floor price of $24.86 per BBL and $4.53 per MMBTU, with additional hedges on 2005 production.

Results of Operations

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Net Income/Loss — Net income for the year ended December 31, 2003 was $2.4 million, or $0.10 per share on a diluted basis, while the net loss for the year ended December 31, 2002 was $38.5 million, or $1.63 per share on a diluted basis. In 2003, our purchase and retirement of $107.6 million principal amount of senior subordinated notes generated a $23.5 million gain, $15.3 million net of tax, on the extinguishment of debt. See "Financial Condition — Financing" section below for additional information about the debt retirement transactions. In 2002, we recognized a $16.7 million goodwill impairment.

Oil and Gas Revenues — Oil and gas revenues were $99.3 million in the year ended December 31, 2003, compared to $112.9 million for the respective period in 2002. The table below details the components of oil and gas revenues and their respective changes between the periods (dollar amounts in millions, except prices):

	Year Ended December 31, 2003	Year Ended December 31, 2002	Change Dollars	Change Percent
Oil revenue	$ 62.3	$ 71.5	$ (9.2)	(12.9)%
Oil hedge settlements	(9.4)	(1.6)	(7.8)	(487)%
Net oil revenue	52.9	69.9		
Gas revenue	52.8	41.7	11.1	26.6%
Gas hedge settlements	(6.4)	1.3	(7.7)	(592)%
Net gas revenue	$ 46.4	$ 43.0		
Oil production (MBBLS)	2,098	3,157	(1,059)	(33.5)%
Gas production (MMCF)	10,314	14,120	(3,806)	(27.0)%
Gas equivalent (MMCFE)	22,902	33,062	(10,160)	(30.7)%
Average sales prices, excluding hedges				
Oil ($ per Bbl)	$ 29.69	$ 22.66	$ 7.03	31.0%
Natural Gas ($ per MCF)	$ 5.12	$ 2.95	$ 2.17	73.6%
Average sales prices, including hedges				
Oil ($ per Bbl)	$ 25.22	$ 22.15	$ 3.07	13.9%
Natural Gas ($ per MCF)	$ 4.50	$ 3.04	$ 1.46	48.0%

The property sales in late 2002 plus the additional sales in the fourth quarter of 2003 are the primary cause of the oil and gas production declines. Gas production increases from drilling, recompletions and workovers done at South Marsh Island, North Leroy and West Lake Verret partially offset the production declines. Because these projects were completed late in 2003, their impact in 2003 is small, but we expect continued production from these projects to benefit our 2004 results.

The favorable impact of high commodity prices offset most of the production decreases. Several factors, including instability in the Middle East and a cold winter, contributed to the commodity price increases.

Costs of Oil and Gas Production — In addition to analyzing gross changes in costs, management finds it useful to look at some costs on a per unit basis. The table below details our costs of oil and gas production by cost type both in dollars incurred and, where useful, in dollars per MCFE, and their respective changes between the periods (dollars in millions, except per unit amounts).

	Year Ended December 31,		Change	
	2003	2002	Dollars	Percent
Lease operating expense	$32.7	$43.2	$(10.5)	(24.3)%
Lease operating expense per MCFE	1.43	1.31	0.12	9.2%
Taxes other than income(1)	8.3	9.2	(0.9)	(9.8)%
Production taxes	5.2	5.0	0.2	4.0%
Property taxes	2.6	3.8	(1.2)	(31.6)%
Other taxes	0.5	0.4	0.1	25.0%
Transportation costs(1)	0.3	0.8	(0.5)	(62.5)%
Depreciation, depletion and amortization	38.5	43.3	(4.8)	(11.1)%
Depreciation, depletion and amortization per MCFE	$1.65	$1.29	$ 0.36	27.9%

(1) Transportation costs and production taxes relate to specific production, therefore analysis of such costs per unit of total production is not useful.

Total lease operating expenses for the year 2003 decreased 24.3% from 2002 levels, but increased 9.2% on a per MCFE basis. Production declines contributed to the per MCFE cost increase. In gross dollars, the most significant cost reductions related to the sale of properties at auction in November 2002, the sale of the Pt. Pedernales field in March 2003, and the sales of the East Texas, East Cameron and Raccoon Bend fields in the fourth quarter of 2003. The East Texas field and the Raccoon Bend field consisted of high per MCFE cost oil properties. We expect the impact of the fourth quarter sales to be evident on a per MCFE basis beginning the first quarter of 2004. Combined with the addition of the low cost per MCFE production from the newly acquired Jalmat field, we expect first quarter 2004 operating expenses to be between $1.25 and $1.35 per MCFE.

Production taxes, depending upon the jurisdiction, are calculated using a percentage of revenue or a per-unit of production rate. They vary with both price and production levels.

Property taxes are assessed based upon property value calculated at the beginning of each year. Our reduced number of properties coupled with reductions in the assessed values of our remaining properties caused the property tax reduction in 2003. Assessed values are based upon beginning of the year reserves and the previous year's average realized price. Because our average realized prices in 2003 were considerably higher than in 2002, we expect property taxes to increase in 2004.

Because our depreciation, depletion and amortization ("DD&A") is calculated on the units of production method, the production decrease resulting from normal production declines and from property sales is driving the overall decline in DD&A expense. The increase in DD&A on a per MCFE basis reflected the impact of decreases in reserves due to property sales.

Asset Retirement Obligation Accretion Expense — Asset retirement obligation accretion expense is a new category of expense for 2003 that resulted from the implementation of SFAS No. 143. The liability recorded for our asset retirement obligation represents the estimate of such costs as of the end of the reporting period. Each quarter, we are required to increase the liability to account for the passage of time, resulting in this accretion expense.

Income Taxes — The federal and state income taxes for the year ended December 31, 2003 was based upon a 36.5% effective tax rate which represented a change from the 23.1% effective tax rate of 2002. The 2002 effective rate, as calculated by dividing income tax benefit by net loss before taxes, was lower primarily because the impairment of goodwill is not an allowable tax deduction.

In December 2003, we have become subject to tax limitations imposed under Section 382 of the Internal Revenue Code ("382 Limitations"). These limitations could impact the potential future realization of our tax net operating losses and other deferred tax assets. Based upon estimates of our recoverable reserves, future production and related taxable income, management has determined that the 382 Limitations have not currently resulted in our deferred assets being impaired.

Interest and Other Income — Interest and other income increased $8.6 million from a net loss of $7.4 million reported for the year 2002 to a net gain of $1.1 million reported for the year 2003. Gains or losses related to hedge ineffectiveness, as computed under the requirements of SFAS. No. 133, are the most significant portion of this line item. A $9.0 million net loss from hedge ineffectiveness was recorded in 2002 while a net gain of $1.0 million was recorded in 2003. A $1.7 million gain from the settlement of a royalty calculation dispute with the MMS was also recorded in 2002.

Interest Expense — Interest expense decreased 4.5% to $25.6 million for the year ended December 31, 2003 from $26.8 million for the year ended December 31, 2002. The following table details the components of interest and their respective changes between the periods (dollar amounts in millions).

	Year Ended December 31,		Change	
	2003	2002	Dollars	Percent
Interest rate swap (gain) loss	$(0.5)	$(2.2)	$ 1.7	77.2%
Interest on 10⅞% notes, net of amortized premium	16.2	24.2	(8.0)	(33.1)%
Amortization of financing costs	2.5	3.0	(0.5)	(16.7)%
Interest on credit facility	7.4	1.8	5.6	311%
Reported interest expense	$25.6	$26.8	$(1.2)	(4.5)%

The interest rate swap was cancelled in February 2003, limiting our exposure to interest rate volatility and resulting in a $520,000 gain recognized in the first quarter of 2003. The March 2003 repurchase of $97.6 million of our 10⅞% senior subordinated notes and their replacement with an $80.0 million term loan facility currently bearing interest at 12% has generated interest savings of approximately $95,000 per month beginning in the second quarter of 2003.

General and Administrative Expenses — General and administrative expenses totaled approximately $10.9 million in the year ended December 31, 2003 and $12.8 million in the year ended December 31, 2002. In 2002, employees of Torch performed most of our accounting, operating and marketing functions, and we paid Torch a management fee for these outsourced services. By the end of April 2003 we had terminated all outsourcing contracts with Torch, decreasing our management fee costs; however, employee costs increased as a result of our increased staffing to replace Torch employees combined with severance costs related to the reorganization partially offsetting the management fee savings.

Some costs incurred in 2003 are not expected to be recurring. Our legal costs were higher as a result of several settled lawsuits and the implementation of the new corporate governance requirements. We also performed an extensive review of our lease and well records in connection with the implementation of a new land system. While many of these costs are not expected to reoccur in 2004, our general and administrative expenses are anticipated to remain near 2003 levels. Because several of the properties that were sold in 2003 were operated, our fees recovered on operated properties will be lower in the future. Public company expenses continue to rise and our salaries and benefits will increase as we grow the company.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Net Income/Loss — Net loss for the year ended December 31, 2002 was $38.5 million, or $1.63 per share on a diluted basis, while the net loss for the year ended December 31, 2001 was $30.9 million, or $1.54 per share on a diluted basis. The contributing factors to such losses are discussed below.

Oil and Gas Revenues — Oil and gas revenues were $112.9 million in the year ended December 31, 2002, compared to $133.2 million for the respective period in 2001. The table below details the components of oil and gas revenues and their respective changes between the periods (dollar amounts in millions, except prices):

	Year Ended December 31,		Change	
	2002	2001	Dollars	Percent
Oil revenue	$ 71.5	$ 70.7	$ 0.8	1.1%
Oil hedge settlements	(1.6)	1.6	(3.2)	(200)%
Net oil revenue	69.9	72.3		
Gas revenue	41.7	75.9	(34.2)	(45.1)%
Gas hedge settlements	1.3	(15.0)	16.3	108.7%
Net gas revenue	43.0	60.9		
Oil production (MBBLS)	3,157	3,235	(78)	(2.4)%
Gas production (MMCF)	14,120	18,575	(4,455)	(24.0)%
Gas equivalent (MMCFE)	33,062	37,985	(4,923)	(13.0)%
Average sales prices, excluding hedges				
Oil ($ per Bbl)	$ 22.66	$ 21.86	$ 0.80	3.7%
Natural Gas ($ per MCF)	$ 2.95	$ 4.09	$ (1.14)	(27.9)%
Average sales prices, including hedges				
Oil ($ per Bbl)	$ 22.15	$ 22.35	$ (0.20)	(0.9)%
Natural Gas ($ per MCF)	$ 3.04	$ 3.28	$ (0.24)	(7.3)%

The expected decreases in our gas production and our realized gas prices, excluding hedges, were the primary reasons for our overall decrease in revenues. Throughout 2002, we sold several oil and gas properties and our production from our offshore properties declines with the passage of time. Additionally, our production was shut in both offshore and along the Gulf coast for a few days during September and October 2002 when hurricanes passed through.

We sold our interests in the Ecuador fields in June 2001. The absence of revenues from Ecuadorian oil accounts for the majority of the decrease in oil revenues.

Costs of Oil and Gas Production — In addition to analyzing gross changes in costs, management finds it useful to also look at some costs on a per unit basis. The table below details our costs of oil and gas production by cost type both in dollars incurred and, where useful, in dollars per MCFE, and their respective changes between the periods (dollars in millions, except per unit amounts).

	Year Ended December 31,		Change	
	2002	2001	Dollars	Percent
Lease operating expense	$43.2	$44.8	$(1.6)	(3.6)%
Lease operating expense per MCFE	$1.31	$1.18	$0.13	11.0%
Taxes other than income(1)	9.2	6.7	2.5	37.3%
Production taxes	5.0	5.2	(0.2)	(3.8)%
Property taxes	3.8	1.2	2.6	217%
Other taxes	0.4	0.3	0.1	33.3%
Transportation costs(1)	0.8	0.1	0.7	700%
Depreciation, depletion and amortization	43.3	45.1	(1.8)	(4.0)%
Depreciation, depletion and amortization per MCFE	$1.29	$1.12	$0.17	15.2%

(1) Transportation costs and production taxes relate to specific production, therefore analysis of such costs per unit of total production is not useful.

Total lease operating expenses for the year 2002 decreased 3.6% from 2001 levels, but increased 11.0% on a per MCFE basis. Cost reductions related to properties sold during 2002 were significant, but the inclusion of a full year of costs from the properties acquired in the 2001 merger with Bargo and the June 2001 South Louisiana acquisition offset that benefit. Many of those acquired properties were high fixed costs properties so that declines in production were not matched with declines in expenses, causing the per MCFE rates to remain high.

Production taxes, depending upon the jurisdiction, are calculated using a percentage of revenue or a per-unit of production rate. Total production taxes vary with both price and production levels.

Property taxes are assessed based upon property value calculated at the beginning of each year. The most significant contribution to increased ad valorem taxes was the 2001 merger with Bargo and the acquisition of South Louisiana properties in 2001 because a full year of property taxes was recognized on those properties in 2002.

Transportation costs represent those expenses incurred to bring production to sale points such as pipeline fees and gas gathering fees. In 2002, we were responsible for paying transportation for more of our oil and gas sales. In 2001, Torch purchased a large portion of our production and assumed responsibility for transportation costs on the gas it purchased from us.

Because our DD&A is calculated on the units of production method, the decrease in production is driving the overall decline in DD&A expense. The increase in DD&A on a per MCFE basis reflected the impact of decreases in reserves as a result of property sales and reserve revisions.

Impairment Expense — The impairment expense reported in 2002 of $16.7 million was the result of the impairment of goodwill. The impairment expense reported in 2001 consisted of a $20.8 million full cost ceiling impairment, a write-off of the $6.2 million long-term receivable and a $914,000 charge for exploration stage mining activities. Both the goodwill and the full cost ceiling impairment are discussed in detail under "Critical Accounting Policies". The long-term receivable represented a production payment receivable due from a foreign energy company that management determined was uncollectible in the fourth quarter of 2001.

Income Taxes — The benefit for federal and state income taxes for the year ended December 31, 2002 was based upon a 35% statutory tax rate. The effective rate was reduced to 23.1%, primarily because the impairment of goodwill is not an allowable tax deduction. Additionally, the $4.3 million valuation allowance on deferred taxes applicable at December 31, 2001 was increased to $5.3 million at December 31, 2002, because management determined that the portion of deferred tax asset relating to state tax losses generated during the period would not be realized. In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon the projection for future state taxable income, management believed it was more likely than not that we would not realize our deferred tax asset related to state income taxes.

Loss on Sale of Assets — The loss on sale of assets of $2.6 million in 2002 was primarily attributable to the post-closing settlement on the sale of our Ecuadorian interests.

Interest and Other Income — Interest and other income decreased $11.8 million from a net gain of $4.4 million reported for the year 2001 to a net loss of $7.4 million reported for the year 2002. Gains or losses related to hedge ineffectiveness, as computed under the requirements of SFAS. No. 133, were the most significant portion of this line item. A net gain from hedge ineffectiveness of $4.8 million was recorded in 2001, while a $9.0 million net loss from hedge ineffectiveness was recorded in 2002. A $1.7 million gain from the settlement of a royalty calculation dispute with the MMS was also recorded in 2002.

Interest Expense — Interest expense increased 13.5% to $26.9 million for the year ended December 31, 2002 from $23.7 million in the year ended December 31, 2001. The following table details the components of interest and their respective changes between the periods (dollar amounts in millions).

	Year Ended December 31,		Change	
	2002	2001	Dollars	Percent
Interest rate swap (gain) loss	$(2.2)	$(0.3)	$(1.9)	(633)%
Interest on 10⅞% notes, net of amortized premium	24.2	18.7	5.5	29.4%
Amortization of financing costs	3.1	2.1	1.0	47.6%
Interest in credit facility	1.8	3.2	(1.4)	43.8%
Reported interest expense	$26.9	$23.7	$ 3.2	13.5%

The $125.0 million of 10⅞% senior subordinated notes that were issued in May of 2001 were outstanding and accruing interest for an additional five months during 2002. The costs of the bond issue were also subject to amortization for the entire year. The change in the fair value of our interest rate swap created gains in both years, but the gain was larger in 2002 because interest rates were decreasing during the year.

General and Administrative Expenses — General and administrative expenses totaled $12.7 million in the year ended December 31, 2002 as compared to $15.2 million in the year ended December 31, 2001, representing a decrease of 16.4%. Salaries and benefits were $3.1 million lower in 2002 than in 2001, because of early 2002 staff reductions. In addition, the termination of outsourcing contracts reduced management fees by $1.6 million in 2002. However, these decreases were partially offset by severance costs of $3.7 million in 2002 compared with $2.5 million of severance and outsourcing contract termination fees in 2001.

Financial Condition

Capital Structure

We have a highly leveraged capital structure, limiting our financial flexibility. In particular, we must pay approximately $22.0 million of interest annually on our long-term debt, which limits the amount of cash that is available for exploration and development of oil and gas properties. In 2002, management began evaluating alternatives to improve Mission's financial position. In 2003, the following steps were taken to enhance our financial condition:

- The March 2003 repurchase and retirement of approximately $97.6 million of our senior subordinated notes financed with a $80.0 million term loan facility.
- The establishment of a new revolving credit facility in June 2003, making $12.5 million available for short-term borrowings.
- The issuance of 4.5 million shares of common stock in exchange for $10 million of our senior subordinated notes in December 2003.
- The sale of high-cost oil properties, making available approximately $25 million for re-investment in gas properties.

We intend to take additional actions in 2004 to continue to improve our financial condition. Among the alternatives that we may consider are

- a refinancing of the remaining notes;
- a new credit facility;
- a merger with or an acquisition by another company;
- the acquisition by Mission of another company or assets;

- other secured and unsecured debt financings; and
- the issuance of equity securities or other debt securities for cash or properties or in exchange for the notes.

Financing

Our outstanding indebtedness totaled $198.5 million at December 31, 2003. The nature of our indebtedness at of December 31, 2003 and 2002 is summarized on the table below (amounts in millions).

	December 31, 2003	December 31, 2002
Revolving credit facility(1)	$ —	$ —
Term loan facility	80.0	—
10⅞% senior subordinated notes	117.4	225.0
Unamortized premium on notes	1.1	1.4
Total debt	$198.5	$226.4

(1) Amounts available for borrowing at December 31, 2003 and 2002 under the revolving credit facilities were $12.5 million and $40.0 million, respectively.

Senior Subordinated Notes

In April 1997, we issued $100.0 million of 10⅞% senior subordinated notes due 2007. On May 29, 2001, we issued an additional $125.0 million of senior subordinated notes due 2007, with identical terms to the notes issued in April 1997, at a premium of $1.9 million. We amortize the premium as a reduction of interest expense over the life of the notes so that the effective interest rate on the additional notes is 10.5%. Through December 31, 2003, we had amortized approximately $740,000 of the premium. Interest on the notes is payable semi-annually on April 1st and October 1st.

We may choose to redeem the notes, in whole or in part, at any time after April 1, 2000 at 105.44% plus accrued and unpaid interest. The required redemption price decreases annually to 100% on April 1, 2005. Should Mission effect a change of control, as defined in the indenture, the noteholders could require us to purchase all or part of the notes for 101% plus accrued and unpaid interest. The notes contain covenants that

- limit indebtedness and liens;
- require compliance with covenants of existing debt, such as our credit facility;
- limit dividend payments and repurchases of capital stock;
- restrict payments to subsidiaries defined by the indenture as restricted subsidiaries;
- control issuance and sales of stock of restricted subsidiaries;
- restrict the disposition of proceeds from asset sales; and
- restrict mergers and consolidations or sales of assets.

On March 28, 2003, we acquired, in a private transaction with various funds affiliated with Farallon Capital Management, LLC, pursuant to the terms of a purchase and sale agreement, approximately $97.6 million in principal amount of the notes for approximately $71.7 million, plus accrued interest. Immediately after the consummation of the transaction, Mission had $127.4 million in principal amount of notes outstanding. Including costs of the transaction and the removal of $2.2 million of previously deferred financing costs related to the acquired notes, we recognized a $22.4 million gain on the extinguishment of the notes.

On December 17, 2003, in a private transaction with FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series, we acquired $10.0 million in principal amount of the notes in exchange for 4.5 million shares of our common stock. The stock was valued at $1.94 per share, the opening price for the transaction date. After netting out costs of the transaction and the removal of previously deferred financing costs and premium related to the acquired notes, we recognized a net gain of approximately $1.1 million on this extinguishment of the notes.

We were in compliance with the covenants of the notes at December 31, 2003. The notes require us to comply with covenants of other existing debt if borrowings under that debt exceed $10.0 million. As discussed below under "Credit Facility", Mission was also in compliance with all covenants of its credit facilities at December 31, 2003.

As of December 31, 2003, Moody's published Mission's subordinated note rating as "Ca". In determining Mission's debt rating, Moody's considers a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges and commodity price levels. A decline in our ratings would not create a default under our current credit facility or other unfavorable change.

Credit Facility

In 2002, Mission was party to a $150.0 million credit facility with a syndicate of lenders. The credit facility was a revolving facility, expiring May 16, 2004, which allowed Mission to borrow, repay and re-borrow under the facility from time to time. The total amount that might be borrowed under the facility was limited by the borrowing base periodically set by the lenders based on Mission's oil and gas reserves and other factors deemed relevant by the lenders. The facility was repaid in full on March 28, 2003.

On March 28, 2003, simultaneously with the acquisition of the notes, Mission amended and restated its credit facility with new lenders, led by Farallon Energy Lending, LLC. Under the amended and restated secured credit agreement (the "Facility"), Mission borrowed $80.0 million pursuant to term loans (the "Term Loan Facility"), the proceeds of which were used to acquire approximately $97.6 million face amount of notes, to pay accrued interest on the notes purchased and to pay closing costs. On June 16, 2003, we amended the Facility to add a revolving credit facility of up to $12.5 million (the "Revolver Facility"), including a letter of credit sub-facility (the "Sub-Facility") of up to $3.0 million. The Facility, which includes the Term Loan Facility and the Revolver Facility, is secured by a lien on substantially all of Mission's property and the property of all of our subsidiaries, including a lien on at least 90% of our respective oil and gas properties and a pledge of the capital stock of all the subsidiaries. The Term Loan Facility expires on January 6, 2005, and the Revolver Facility expires on June 6, 2006.

The proceeds of the Revolver Facility are to be used to finance our ongoing working capital and general corporate needs. As of December 31, 2003, we had no amounts outstanding under the Revolver Facility, but had issued $100,000 of letters of credit under the Sub-Facility. Subject to the terms and conditions of the Revolver Facility, the lenders have agreed to make advances to Mission, from time to time, prior to the expiration of the Revolver Facility, in an amount equal to the least of the following (in whole multiples of $1,000,000):

(i) $12.5 million minus outstanding letters of credit,

(ii) the Borrowing Base (as defined below) minus outstanding letters of credit, and

(iii) during a Cleanup Period (as defined below), $3.0 million minus outstanding letters of credit in excess of $1.0 million.

"Borrowing Base" means an amount equal to 10% of the PV-10 Value (as defined in the Facility) of the our proved developed producing reserves minus certain other reserves required under the Facility. The

Borrowing Base was $13.2 million at December 31, 2003. A "Cleanup Period" is either of the following periods if principal amounts under the Term Loan Facility are outstanding:

(x) the 30-day period following any 90-day period in which the amount outstanding under the Revolver Facility exceeds $3.0 million for each day, or

(y) the one-day period immediately following any required payment on any indebtedness subordinate to the Facility.

The interest rate under the Term Loan Facility is 12% until February 16, 2004, when it increases to 13% until the Maturity Date. The interest rate under the Revolver Facility is equal to the prime rate plus 0.5% per annum, provided that the minimum interest rate is 4.75% per annum. Outstanding letters of credit are charged a letter of credit fee equal to 3.0% per annum.

The Facility contains covenants that limit our capital expenditures, except for capital expenditures in the ordinary course of business that:

- do not exceed the amount approved by the majority lenders for fiscal year 2004; or
- are financed out of the net cash proceeds of issuances of capital stock (effected during a 30 day period) in excess of $20.0 million or out of the net cash proceeds of asset sales, with an aggregate limit of $50.0 million during the term of the loans outstanding under the Facility (the "Loans"), (i) of up to $5.0 million during the term of the Loans, and (ii) that are paid for the acquisition of replacement assets either 90 days before or 90 days after the asset sale or recovery event.

For fiscal years 2005 and thereafter, our capital expenditures cannot exceed the amounts approved by the administrative agent and the majority lenders.

In addition, there are certain other financial covenants in the Facility that we consider important in operating our business:

- minimum consolidated EBITDA, as of the last day of any fiscal quarter, for the period of two fiscal quarters that end on such day, of $17.5 million;
- maximum Leverage Ratio (as defined below) as at the last day of any fiscal quarter of 2.75 to 1; and
- minimum Consolidated Fixed Charge Coverage Ratio (as defined below), must be 1.00 to 1.00 at each fiscal quarter's end on a cumulative basis for the first eight fiscal quarters. Thereafter the ratio must be 1.25 to 1.00 at quarter's end for the total of the four preceding fiscal quarters.

"Leverage Ratio" is the ratio of (a) the principal amount of the Loans plus the principal amount of all indebtedness that is equal to or senior in right of payment to the Loans to (b) consolidated EBITDA for the period of four quarters ending on such day. "Consolidated Fixed Charge Coverage Ratio" for any period, is the ratio of: (a) the consolidated EBITDA during such period plus, for each applicable test period ended on March 31, June 30, September 30, and December 31, of calendar years 2003 and 2004, plus $12,000,000 to (b) the sum of (i) our capital expenditures during such period plus (ii) the cash income tax expense for such period plus (iii) our cash consolidated interest expense for such period to the extent paid or required to be paid during such period.

The Facility contains additional covenants that limit our ability, among other things, to incur additional indebtedness or to create or incur liens; to merge, consolidate, liquidate, wind-up or dissolve; to dispose of property; and to pay dividends on or redeem stock. As of December 31, 2003, we were in compliance with the covenants in the Facility.

At current oil and gas price levels, we expect to be in compliance with all of the credit facility covenants throughout 2004. Declining commodity prices or rising expenses could prevent us from meeting the credit facility covenants. In that event, we would attempt to negotiate an amendment or a waiver of the covenants from our lenders. Should the lenders fail to approve our requests, then we would attempt to obtain the funds to repay the outstanding credit facility debt through property sales or equity financing. We cannot assure you that we would be successful in completing any of these possible actions.

Liquidity and Capital Resources

Mission's principal sources of capital for the last three years have been cash flow from operations, debt sources such as the issuance of bonds or credit facility borrowings, issuances of common stock, and the sale of oil and gas properties. Our primary uses of capital have been the funding of the retirement of senior subordinated notes, exploration and development projects and property acquisitions.

At December 31, 2003, we had working capital of $13.2 million compared to $0.9 million at December 31, 2002. Cash held for reinvestment in oil and gas properties of approximately $24.9 million is included in the December 31, 2003 working capital amount. Approximately $24.9 million of the proceeds from 2003 property sales were held for reinvestment at December 31, 2003. On January 30, 2004, we acquired the Jalmat field for $26.6 million, using these proceeds plus operating cash flow. When this cash held for reinvestment is excluded, our working capital becomes negative. The addition of a current obligation for asset retirement as a result of the implementation of SFAS No. 143 and the unfavorable impact of increased commodity prices on our hedges' fair value contributed most significantly to working capital reduction in 2003. The hedge liability represents the extent to which actual commodity prices exceed the price caps set by our hedges. Should commodity prices decrease, the liability will decline and the premium over the hedge prices that we will realize on unhedged production will also reduce. Since hedges are settled out of the receipts from the sale of production, we anticipate having adequate cash inflows to settle any hedge payments when they come due while maintaining revenue near the hedge price. We believe that cash flows from operating activities combined with our ability to control the timing of substantially all of our future exploration and development requirements will provide us with the flexibility and liquidity to meet our planned capital requirements for 2004. Our Revolver Facility is also available for short-term borrowings.

Source of Capital: Operations

Cash flow provided by operating activities totaled $18.8 million, $7.2 million, and $40.4 million for the fiscal years 2003, 2002, and 2001, respectively. Our operating cash flow is sensitive to many variables, with prices of oil, natural gas and NGL being the most volatile. Prices are determined primarily by prevailing market conditions. Regional and worldwide economic growth, weather and other variable factors influence market conditions. We are not able to control these factors and may not be able to accurately predict prices.

To mitigate some of the risk inherent in oil and natural gas prices, we hedge our oil and natural gas production by entering into commodity price swaps or collars designed to set minimum prices and maximum prices, or both, on a portion of our production. See "Item 7A — Quantitative and Qualitative Disclosures About Market Risk" for a more detailed discussion of commodity price risk and a listing of our current hedges.

Source of Capital: Debt

Our outstanding balance under the 10⅞% senior subordinated notes was $117.4 million at December 31, 2003 and was $225.0 million at December 31, 2002 and 2001. In 2003, we purchased and retired $107.6 million of notes in two transactions for $71.7 million in cash, from a $80.0 million term loan facility established in March 2003, and by exchanging 4.5 million shares of common stock.

Borrowings under our credit facilities were $80.0 million in term loans at December 31, 2003 and $35.0 million at the end of 2001. There were no borrowings outstanding under our credit facility at December 31, 2002. Additionally, we have $12.5 million of credit available under the Revolver Facility as of December 31, 2003. As previously discussed under "Financing Activities," both our notes and our credit facility contain covenants limiting our activities or requiring that we maintain specific financial ratios. As of December 31, 2003, we were in compliance with all applicable covenants.

Declining commodity prices or rising expenses could prevent us from meeting the credit facility covenants. In that event, we would attempt to negotiate an amendment or a waiver of the covenants from our lenders. Should the lenders fail to approve our requests, then we would attempt to obtain the funds to repay the outstanding credit facility debt through property sales or equity financing. We cannot assure you that we would be successful in completing any of these possible actions.

Source of Capital: Issuance of Common Stock

We issued 4.5 million shares of common stock on December 17, 2003 to FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series in order to acquire $10.0 million principal amount value of the senior subordinated notes. These shares of common stock are currently registered for resale under an effective registration statement. In February 2004, we acquired $15.0 million of our $10\frac{7}{8}$% senior subordinated notes due 2007 for 6.25 million shares of common stock in a transaction with Stellar Funding, Ltd. In addition, we have agreed to register the resale of these shares of common stock.

Source of Capital: Sale of Properties

We continue to evaluate and assess our property portfolio and capital needs, and we may from time to time sell certain properties as appropriate. Net proceeds from the sales of oil and gas properties were approximately $28.1 million in 2003, $60.4 million in 2002, and $15.9 million in 2001. Net proceeds are gross proceeds adjusted for transaction costs and interim operations. We also sold our Ecuadorian interests for approximately $4.8 million in June 2001 and our interests in the Snyder and Diamond M gas plants for $10.9 million in late 2001.

Use of Capital: Exploration and Development

Mission's expenditures for exploration, including land and seismic costs, and development of its domestic oil and gas properties totaled $33.4 million, $20.6 million, and $44.6 million for the fiscal years 2003, 2002, and 2001, respectively. We also spent $3.9 million in the year 2001 on the development of fields in Ecuador.

Our capital budget for 2004 is $32.0 million to $34.0 million. Approximately 60% of the total is planned for development projects, while 20% is planned for exploration. The remaining 20% is planned for seismic data, land and land-related assets and corporate assets. Based upon the level of funding needed for development, the level of exploratory spending could be modified to meet the budget in total. This capital budget represents the largest planned use of our available operating cash flow. We believe that cash flows from operating activities combined with our ability to control the timing of substantially all of our future exploration and development requirements will provide us with the flexibility and liquidity to meet our planned capital requirements for 2004. Our intent is to apply less than our discretionary cash flow to capital projects in 2004; therefore, the budget could be modified throughout the year to the extent that we can control the timing of capital expenditures.

Use of Capital: Acquisitions and Other Corporate Assets

In 2003, spending for oil and gas property acquisitions was approximately $1.6 million. The most significant individual acquisition was that of an additional interest in High Island Block A-553 for approximately $621,000. We did not make any significant oil and gas property acquisitions during 2002. The merger with Bargo, valued at $280.9 million, was our most significant acquisition of 2001. Other domestic property acquisitions totaled $23.4 million in the year 2001.

We invested approximately $1.0 million in other corporate assets during 2003. These assets include a new computer system for land records and office expansion to accommodate our growing workforce. Approximately $1.3 million will be spent in 2004 for corporate assets.

We continuously review acquisition opportunities and would first consider utilizing operating cash flows to make a desired acquisition. For larger acquisitions, our credit facility or the issuance of equity securities could provide the necessary funds, however, we cannot assure you that either of these sources would be able to provide funds adequate to complete every desired acquisition.

Approximately $24.9 million of the proceeds from 2003 property sales was held for reinvestment at December 31, 2003. The proceeds were used to fund the $26.6 million acquisition of the Jalmat field in the Permian Basin.

Use of Capital: Contractual Obligations and Commercial Commitments

Mission is required to make future payments under contractual obligations. The following table details those future payments (amounts in thousands):

Contractual Cash Obligations:	Total	2004	2005	2006	2007	2008	Thereafter
Long term debt*	$158,929	$12,770	$12,770	$12,770	$120,619	$—	$—
Line of credit	90,499	10,328	80,171	—	—	—	—
Operating leases	2,254	868	708	677	1	—	—
Total Contractual Obligations	$251,682	$23,966	$93,649	$13,447	$120,620	$—	$—

* Includes bond principal of $117.4 million scheduled for repayment in 2007 and bond interest accrued monthly and payable April 1st and October 1st of each year.

Mission has also made various commitments in the future should certain events occur or conditions exist. The estimated payments related to those commitments are scheduled on the table below (amounts in thousands):

Commercial Commitments:	Total	2004	2005	2006	2007	2008	Thereafter
Other Commercial Commitments*	4,980	4,071	336	262	173	138	—

* Includes delay rentals required to hold undeveloped acres for future drilling.

Critical Accounting Policies

In response to SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we identified those policies of particular importance to the portrayal of our financial position and results of operations and those policies that require our management to apply significant judgment. We believe these critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

Full Cost Method of Accounting for Oil and Gas Assets

We use the full cost method of accounting for investments in oil and gas properties. Under the full cost method of accounting, all costs of acquisition, exploration and development of oil and gas reserves are capitalized as incurred into a "full cost pool". Under the full cost method, a portion of employee-related costs may be capitalized in the full cost pool if they are directly identified with acquisition, exploration and development activities. Generally, salaries and benefits are allocated based upon time spent on projects. Amounts capitalized can be significant when exploration and major development activities increase.

We deplete the capitalized costs in the full cost pool, plus estimated future expenditures to develop reserves, on a prospective basis using the units of production method based upon the ratio of current production to total proved reserves. Depreciation, depletion and amortization is a significant component of our net income. Proportionally, it represented 38% of our total oil and gas revenues in the years ended December 31, 2003 and 2002. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate. If during 2004, our reserves increase by 10%, our depletion per MCFE would decrease approximately $0.18, or 9%; however, a 10% decrease in reserves will have a 11% impact, increasing depletion per MCFE by approximately $0.21.

Both the volume of proved reserves and the estimated future expenditures used for the depletion calculation are obtained from the reserve estimates prepared by independent reserve engineers. These reserve estimates rely upon both the engineers' quantitative and subjective analysis of various data, such as engineering data, production trends and forecasts, estimated future spending and the timing of spending. Finally, estimated production costs and commodity prices are added to the assessment in order to determine whether the estimated reserves have any value. Reserves that cannot be produced and sold at a profit are not included in the estimated total proved reserves; therefore the quantity of reserves can increase or decrease as oil and gas prices change. See "Risk Factors: Risks Related to Our Business, Industry and Strategy" for general cautions concerning the reliability of reserve and future net revenue estimates by reserve engineers.

The full cost method requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full cost ceiling calculation. The ceiling is the discounted present value of our estimated total proved reserves adjusted for taxes, using a 10% discount rate. To the extent that our capitalized costs (net of depreciation, depletion, amortization, and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of oil and gas properties is not reversible at a later date even if oil and gas prices increase. No such impairment was required in the years ended December 31, 2003 and 2002.

While the difficulty in estimating proved reserves could cause the likelihood of a ceiling impairment to be difficult to predict, the impact of changes in oil and gas prices is most significant. In general, the ceiling is lower when prices are lower. Oil and gas prices at the end of the period are applied to the estimated reserves, then costs are deducted to arrive at future net revenues, which are then discounted at 10% to arrive at the discounted present value of proved reserves. Additionally, we adjust the estimated future revenues for the impact of our existing cash flow commodity hedges. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on Mission's assessment of future prices or costs, but rather are based on prices and costs in effect as of the end the period.

Because the ceiling calculation dictates that prices in effect as of the last day of the period be held constant, the resulting value is rarely indicative of the true fair value of our reserves. Oil and natural gas prices have historically been variable and, on any particular day at the end of a period, can be either substantially higher or lower than our long-term price forecast, which we feel is more indicative of our reserve value. You should not view full cost ceiling impairments caused by fluctuating prices, as opposed to reductions in reserve volumes, as an absolute indicator of a reduction in the ultimate value of our reserves.

Oil and gas prices used in the ceiling calculation at December 31, 2003 were $32.47 per barrel and $5.97 per MMBTU. A significant reduction in these prices at a future measurement date could trigger a full cost ceiling impairment. As an illustration, had oil and gas prices at December 31, 2003 been 10% lower, we would have been 69% closer to a ceiling impairment. Our hedging program would serve to mitigate some of the impact of any price decline. If our hedges were excluded from the ceiling calculation, we would have been 62% closer to a ceiling impairment.

Derivative Instruments Accounting

All of our commodity derivative instruments represent hedges of the price of future oil and natural gas production. We estimate the fair values of our hedges at the end of each reporting period. The estimated fair values of our commodity derivative instruments are recorded in the consolidated Balance Sheet as assets or liabilities as appropriate.

For effective hedges, we record the change in the fair value of the hedge instruments to other comprehensive income, a component of stockholders' equity, until the hedged oil or natural gas quantities are produced. Any ineffectiveness in our hedges, which could represent either gains or losses, is reported when calculated as part of the interest and other income line of the Statement of Operations

Estimating the fair values of commodity hedge derivatives requires complex calculations, including the use of a discounted cash flow technique and our subjective judgment in selecting an appropriate discount rate. In addition, the calculation uses future NYMEX prices, which although posted for trading purposes, are merely the market consensus of forecast price trends. The results of our fair value calculation cannot be expected to represent exactly the fair value of our commodity hedges. We currently use a software product from an outside vendor to calculate the fair value of our hedges. This vendor provides the necessary NYMEX futures prices and the calculated volatility in those prices to us daily. The software is programmed to apply a consistent discounted cash flow technique, using these variables and a discount rate derived from prevailing interest rates. This software is successfully used by several of our peers. Its methods are in compliance with the requirements of SFAS No. 133 and have been reviewed by a national accounting firm.

Revenue Recognition

Mission records revenues from sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a tanker lifting has occurred. We may share ownership with other producers in certain properties. In this case, we use the sales method to account for sales of production. It is customary in the industry for various working interest partners to sell more or less than their entitled share of natural gas production, creating gas imbalances. Under the sales method, gas sales are recorded when revenue checks are received or are receivable on the accrual basis. Typically no provision is made on the Balance Sheet to account for potential amounts due to or from Mission related to gas imbalances. If the gas reserves attributable to a property have depleted to the point that there are insufficient reserves to satisfy existing imbalance positions, a liability or a receivable, as appropriate, should be recorded equal to the net value of the imbalance. As of December 31, 2003, the Company had recorded a net liability of approximately $1.1 million, representing approximately 379,000 MCF at an average price of $2.95 per MCF, related to imbalances on properties at or nearing depletion. The net liability accrued as of December 31, 2002, was $454,000 for approximately 266,000 MCF at an average price of $1.71 per MCF. We value gas imbalances using the price at which the imbalance originated, if required by the gas balancing agreement, or we use the current price where there is no gas balancing agreement available. Reserve changes on any fields that have imbalances could change this liability. We do not anticipate the settlement of gas imbalances to adversely impact our financial condition in the future. Settlements are typically negotiated, so the per Mcf price for which imbalances are settled could differ among wells and even among owners in one well. Exclusive of the liability recorded for properties at or nearing depletion (see discussion above), the Company's unrecorded imbalance, valued at current prices would be a $1.7 million liability.

Asset Retirement, Impairment or Disposal

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003. Previously our estimate of future plugging and abandonment and dismantlement costs was charged to income by being included in the capitalized costs that we depleted using the unit of production method. SFAS No. 143 requires us to record a liability for the fair value of our estimated asset retirement obligation, primarily comprised of our plugging and abandonment liabilities, in the period in which it is incurred. Upon initial implementation, we estimate asset retirement costs for all of our assets as of such date, inflation adjust those costs to the forecast abandonment date, discount that amount back to the date we acquired the asset and record an asset retirement liability in that amount with a corresponding addition to our asset value. Then we must compute all depletion previously taken on future plugging and abandonment costs, and reverse that depletion. Finally, we must accrete the liability to present day. Any income effect of this initial implementation is reflected as a change in accounting method on our Statement of Operations.

After initial implementation, we will reduce the liability as abandonment costs are incurred. Should actual costs incurred to abandon a field differ from the estimate, the difference will be reflected as an abandonment gain or loss in the Statement of Operations when the field is abandoned. We will accrete the liability quarterly using the period and effective interest rates determined at implementation. As new wells are drilled or purchased their initial asset retirement cost and liability will be calculated and recorded. We have developed a process through which to track and monitor the obligations for each asset following implementation of SFAS No. 143.

When wells are sold the related liability and asset cost are removed from the Balance Sheet. Any difference between the two remains in the full cost pool. SFAS No. 143 does not specifically address the proper accounting to be applied by a full cost method company when properties are sold. A May 23, 2003 letter to the FASB and the SEC from a group of concerned companies makes inquiries and outlines possible alternatives, including our current treatment. Should a clarification be issued, there is a chance that Mission's treatment will be required to change and the entire $2.2 million credit that is in our full cost pool for 2003 would have to be included in income.

As with previously discussed estimates, the estimation of our initial liability and its subsequent remeasurements is dependent upon many variables. We attempt to limit the impact of management's judgment on these variables by using the input of qualified third parties when possible. We engaged an independent engineering firm to evaluate our properties annually and to provide us with estimates of abandonment costs. We used the remaining estimated useful life from the yearend Netherland, Sewell & Associates, Inc. reserve report in estimating when abandonment could be expected for each property. The resulting estimate, after application of a discount factor and some significant calculations, could differ from actual results, despite all our efforts to make the most accurate estimation possible.

Should either the estimated life or the estimated abandonment costs of a property change upon subsequent review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our risked rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost.

Income Taxes

Mission has accumulated substantial income tax deductions that have not yet been used to reduce cash income taxes actually paid with the filing of our income tax returns. These accumulated deductions are commonly referred to as "net operating loss carryforwards" or "NOLs".

Our NOLs are, subject to a number of restrictions, available to reduce cash taxes that may become owed in future years. In accordance with the accounting for income taxes under SFAS No. 109, we record a deferred tax asset and a reduction of our tax expense for our NOLs. If we estimate that some or all of our NOL's are more likely than not going to expire or otherwise not be utilized to reduce future tax, we record a valuation allowance to remove the benefit of those NOL's from our financial statements

One of the restrictions on the future use of NOLs is contained in Section 382 of the Internal Revenue Code. In general, Section 382 provides that the amount of existing NOLs that may be used to offset future taxable income after the occurrence of an "ownership change" (as defined solely for Section 382 purposes) is limited to an amount that is determined, in part, by the fair market value of the enterprise at the time the ownership change occurred. The fair market value of the enterprise's individual assets and the timing in which the value of those assets are realized are also factors that impact the amount of NOLs available under Section 382 ("382 Limitation").

As a result of our issuance of common stock in exchange for the retirement of a portion of our 10⅞% senior subordinated notes in December 2003, we experienced an "ownership change" as defined under Section 382. Consequently, we have included the estimated impact that a 382 Limitation may have upon the future availability of our NOLs as part of our evaluation under SFAS 109.

Consistent with previously described estimates, the initial estimation of the future benefit of our NOLs is dependent upon many variables and is subject to change. Management's judgment on these variables is based upon the input of qualified third parties when possible. We have used information derived from the public equity markets as well as data provided by an independent engineering firm to assist us with determining fair market values. We have engaged an international independent public accounting firm to assist us in applying the numerous and complicated tax law requirements. However, despite our attempt to make the most accurate estimates possible, the ultimate utilization of our NOLs is highly dependent upon our actual production and the realization of taxable income in future periods.

Other Matters

Dividends

At present, there is no plan to pay dividends on our common stock. Certain restrictions contained in Mission's outstanding notes and credit facility limit the amount of dividends that may be declared.

New Accounting Pronouncements

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statements No. 13 and Technical Corrections,* was issued in April 2002. SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishments of debt to prohibit the classification of the gain or loss as extraordinary, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provision of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. Mission applied the provisions of SFAS No. 145 as they relate to the extinguishment of debt in accounting for the March 28, 2003 senior subordinated note repurchase and the December 17, 2003 debt for equity swap which are further discussed in the notes to consolidated financial statements at footnote 8.

SFAS No. 146, *Accounting for Exit or Disposal Activities,* was issued in June 2002. SFAS No. 146 addresses significant issues regarding the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, *Liability Recognition of Certain Employee Termination Benefits and Other Costs to Exit an Activity.* SFAS No. 146 is effective for the exit and disposal activities initiated after December 31, 2002. We applied SFAS No. 146 to the closings of our offices located in Longview, Texas and Belleville, Texas. The fields served by these offices were sold during the fourth quarter of 2003. All activities required to close the offices and to establish one replacement office nearer to the Company's remaining operated properties were concluded during 2003. An aggregate loss of approximately $136,000 was recognized in connection with these office closings, with almost $122,000 of the total related to severance payments made in accordance with Mission's existing severance plan. This loss is included in the interest and other income line of the Statement of Operations.

In November 2002, FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34.* This interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the interpretation are applicable to guarantees issued or modified after December 31, 2002 and were not expected to materially effect our financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 15, 2002 and can be found in the notes to consolidated financial statements at footnote 12.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment of SFAS No. 123,* that provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements. Some of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to consolidated financial statements at footnotes 2 and 5.

FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities,* an interpretation of APB No. 51, in January 2003. This interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the interpretation. The interpretation applied immediately to variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. Significant changes to this interpretation were proposed by FASB in October 2003, including delaying the effective date to the beginning of the first reporting period ending after December 15, 2003. Mission does not currently own an interest in any variable interest entities; therefore, this interpretation does not have a material effect on its financial statements. We will apply the provisions of this interpretation in the future should we acquire or establish a variable interest entity.

SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities Summary* was issued in April 2003. This statement amends and clarifies the accounting and reporting for derivative instruments, including embedded derivatives, and for hedging activities under SFAS No. 133. Statement 149 amends Statement 133 to reflect the decisions made as part of the Derivatives Implementation Group (DIG) and in other FASB projects or deliberations. Statement 149 is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. Mission has applied the pertinent DIG interpretations as they were issued and does not expect SFAS No. 149 will have a material impact on our financial statements.

SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* was issued in May 2003. SFAS No. 150 provides guidance on how to classify and measure certain financial instruments with characteristics of both liabilities and equity. Many of these instruments were previously classified as equity. This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The statement requires cumulative effect transition for financial instruments existing at adoption date. None of our financial instruments were impacted by this statement.

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

Mission is exposed to market risk, including adverse changes in commodity prices and interest rates. To the extent that we use derivative instruments to mitigate these risks, we are also exposed to credit risk.

Commodity Price Risk

Mission produces and sells crude oil, natural gas and natural gas liquids. As a result, our operating results can be significantly affected by fluctuations in commodity prices caused by changing market forces. We periodically seek to reduce our exposure to price volatility by hedging a portion of production through swaps, options and other commodity derivative instruments. A combination of options, structured as a collar, is our preferred hedge instrument because there are no up-front costs and protection is given against low prices. These collars assure that the NYMEX prices we receive on the hedged production will be no lower than the price floor and no higher than the price ceiling. The oil hedges that are swaps fix the price to be received.

Our realized price, excluding hedges, for natural gas per MCF is generally \$0.19 less than the NYMEX MMBTU price. Our realized price, excluding hedges, for oil is generally \$0.81 per BBL less than NYMEX. Realized prices differ from NYMEX due to factors such as the location of the property, the heating content of natural gas and the quality of oil. The oil differential excludes the impact of Point Pedernales field production for which our selling price is capped at \$9.00 per BBL. The Point Pedernales field was sold in March 2003 to the operator. The gas differential stated above excludes the impact of the Mist field gas production, which is sold at an annually fixed price.

In May 2002 several existing oil collars were cancelled. New swaps and collars hedging forecast oil production were acquired. We paid approximately $3.3 million, the fair value of the previous oil price collars at that time, to counter parties in order to cancel the transactions.

By removing the price volatility from hedged volumes of oil and natural gas production, we have mitigated, but not eliminated, the potential negative effect of declining prices on our operating cash flow. The potential for increased operating cash flow due to increasing prices has also been reduced. If all our commodity hedges were to settle at December 31, 2003 prices, our cash flows would decrease by $10.5 million; however the actual settlement of our hedges will increase or decrease cash flows over the period of the hedges at varying prices.

The following tables detail our commodity hedges as of March 8, 2004.

Oil Hedges

Period	BBLS Per Day	Total BBLS	Type	NYMEX Price Floor/Swap Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2004	2,500	227,500	Swap	$25.24	N/A
First Qtr. 2004	1,000	91,000	Collar	$28.00	$30.42
Second Qtr. 2004	2,500	227,500	Swap	$24.67	N/A
Third Qtr. 2004	2,500	230,000	Swap	$24.30	N/A
Fourth Qtr. 2004	2,500	230,000	Swap	$23.97	N/A
First Qtr. 2005	1,500	135,000	Collar	$26.83	$29.42
Second Qtr. 2005	1,500	136,500	Collar	$26.33	$28.79
Third Qtr. 2005	1,500	138,000	Collar	$26.17	$27.90
Fourth Qtr. 2005	1,500	138,000	Collar	$26.00	$27.33

Gas Hedges

Period	MMBTU Per Day	Total MMBTU	Type	NYMEX Price Floor Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2004	15,000	1,365,000	Collar	$4.80	$6.11
Second Qtr. 2004	14,000	1,274,000	Collar	$4.43	$5.10
Third Qtr. 2004	14,000	1,288,000	Collar	$4.43	$4.99
Fourth Qtr. 2004	14,000	1,288,000	Collar	$4.48	$5.31
First Qtr. 2005	5,000	450,000	Collar	$4.65	$6.93
Second Qtr. 2005	5,000	455,000	Collar	$4.45	$5.39
Third Qtr. 2005	5,000	460,000	Collar	$4.45	$5.35
Fourth Qtr. 2005	5,000	460,000	Collar	$4.45	$5.76

Credit Risk

These commodity hedges expose Mission to counter party credit risk to the extent the counter party is unable to meet its monthly settlement commitment to us. We believe that we select creditworthy counter parties to our hedge transactions. Each of our counter parties have long-term senior unsecured debt ratings of at least A/A2 by Standard & Poor's or Moody's.

Interest Rate Risk

Effective September 22, 1998, Mission entered into an eight and one-half year interest rate swap agreement with a notional value of $80.0 million. Under the agreement, Mission received a fixed interest rate and paid a floating interest rate, subject to a cap, based on the simple average of three foreign LIBOR rates. Mission paid $1.3 million to the counter party in February 2003 to cancel the swap. A $520,000 gain related to the change in the fair market value of the swap from January 1, 2003 to the date of cancellation was recognized as a reduction in interest expense.

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

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Mission Resources Corporation and Subsidiaries:

We have audited the accompanying consolidated balance sheets of Mission Resources Corporation (formerly Bellwether Exploration Company) and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, changes in stockholders' equity and comprehensive loss, and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

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

As discussed in note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." As discussed in note 2 to the consolidated financial statements, effective January 1, 2002, the Company adopted the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets." As discussed in note 2 to the consolidated financial statements, effective January 1, 2001, the Company adopted the provisions of SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities."

KPMG LLP
Houston, Texas
February 27, 2004

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(Amounts in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,234	$ 11,347
Cash held for reinvestment	24,877	—
Accounts receivable	6,327	8,640
Accrued revenues	8,417	10,291
Prepaid expenses and other	2,523	2,148
Total current assets	44,378	32,426
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties *(full cost)*		
Unproved properties of $6,123 and $8,369 excluded from amortization as of December 31, 2003 and 2002, respectively	816,887	775,344
Accumulated depreciation, depletion and amortization	(514,759)	(474,625)
Net property, plant and equipment	302,128	300,719
Leasehold, furniture and equipment	4,405	3,545
Accumulated depreciation	(2,065)	(1,449)
Net leasehold, furniture and equipment	2,340	2,096
OTHER ASSETS	5,404	7,163
	$ 354,250	$ 342,404

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	December 31, 2003	December 31, 2002
	(Amounts in thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 8,864	$ 9,444
Accrued liabilities	9,131	8,879
Interest payable	3,425	6,175
Commodity derivative liabilities	8,597	6,973
Current portion of asset retirement obligation	1,160	—
Current portion of interest rate swap	—	3
Total current liabilities	31,177	31,474
LONG-TERM DEBT:		
Term loan facility	80,000	—
Senior subordinated notes due 2007	117,426	225,000
Unamortized premium on issuance of senior subordinated notes due 2007	1,070	1,431
Total long-term debt	198,496	226,431
LONG-TERM LIABILITIES:		
Commodity derivative liabilities, excluding current portion	80	359
Interest rate swap, excluding current portion	—	1,817
Deferred income taxes	17,270	16,946
Other liabilities	130	—
Asset retirement obligation, excluding current portion	32,157	—
Total long-term liabilities	49,637	19,122
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 5,000,000 shares authorized; none issued or outstanding at December 31, 2003 and 2002	—	—
Common stock, $0.01 par value, 60,000,000 shares authorized, 28,017,636 and 23,896,959 shares issued at December 31, 2003 and December 31, 2002, respectively	284	239
Additional paid-in capital	172,532	163,837
Retained deficit	(90,232)	(92,599)
Treasury stock, at cost, of 389,000 shares and 311,000 shares at December 31, 2003 and 2002, respectively	(1,937)	(1,905)
Other comprehensive income, net of taxes	(5,707)	(4,195)
Total stockholders' equity	74,940	65,377
	$ 354,250	$ 342,404

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2003	2002	2001
	(Amounts in thousands, except per share data)		
REVENUES:			
Gas revenues	$ 46,443	$ 42,953	$ 60,924
Oil revenues	52,914	69,926	72,311
Gain on extinguishment of debt	23,476	—	—
Gas plant revenues	—	—	4,456
Interest and other income (expense)	1,141	(7,415)	4,386
	123,974	105,464	142,077
COSTS AND EXPENSES:			
Lease operating expenses	32,728	43,222	44,773
Taxes other than income	8,251	9,246	6,656
Transportation costs	349	834	73
Gas plant expenses	—	—	2,118
Asset retirement obligation accretion expense	1,263	—	—
Depreciation, depletion and amortization	38,501	43,291	45,106
Impairment expense	—	16,679	27,971
Uncollectible gas revenues	—	—	2,189
Loss on sale of assets	—	2,645	11,600
General and administrative expenses	10,856	12,758	15,160
Interest expense	25,565	26,853	23,664
	117,513	155,528	179,310
Income (loss) before income taxes and cumulative effect of a change in accounting method	6,461	(50,064)	(37,233)
Income tax expense (benefit)	2,358	(11,580)	(9,055)
Income (loss) before cumulative effect of a change in accounting method	4,103	(38,484)	(28,178)
Cumulative effect of a change in accounting method, net of tax of $935 and $1,633	1,736	—	2,767
Net income (loss)	$ 2,367	$(38,484)	$(30,945)
Income (loss) per share before cumulative effect of a change in accounting method	$ 0.17	$ (1.63)	$ (1.41)
Income (loss) per share before cumulative effect of a change in accounting method — diluted	$ 0.17	$ (1.63)	$ (1.41)
Net income (loss) per share	$ 0.10	$ (1.63)	$ (1.54)
Net income (loss) per share — diluted	$ 0.10	$ (1.63)	$ (1.54)
Weighted average common shares outstanding	23,696	23,586	20,051
Weighted average common shares outstanding — diluted	24,737	23,586	20,051

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME OR LOSS

	Common Stock		Preferred Stock		Additional Paid-In Capital	Other Comprehensive Income	Retained Deficit	Treasury Stock		Total
	Shares	Amount	Shares	Amount				Shares	Amount	
					(Amounts in thousands)					
December 31, 2000	14,260	$143	—	$—	$ 81,892	$ —	$(23,170)	(311)	$(1,905)	$56,960
Stock options exercised and related tax effects	177	2	—	—	1,138	—	—	—	—	1,140
Issuance of common stock related to merger	9,460	94	—	—	79,906	—	—	—	—	80,000
Compensation expense —										
Stock options	—	—	—	—	799	—	—	—	—	799
Comprehensive loss:										
Net loss	—	—	—	—	—	—	(30,945)	—	—	(30,945)
Hedge activity	—	—	—	—	—	2,286	—	—	—	2,286
Total comprehensive loss										(28,659)
December 31, 2001	23,897	239	—	—	163,735	2,286	(54,115)	(311)	(1,905)	110,240
Compensation expense —										
Stock options	—	—	—	—	102	—	—	—	—	102
Comprehensive loss:										
Net loss	—	—	—	—	—	—	(38,484)	—	—	(38,484)
Hedge activity	—	—	—	—	—	(6,481)	—	—	—	(6,481)
Total comprehensive loss										(44,965)
December 31, 2002	23,897	239	—	—	163,837	(4,195)	(92,599)	(311)	(1,905)	65,377
Stock options exercised and related tax effects	10	—	—	—	10	—	—	—	—	10
Issuance of common stock related to debt retirement	4,500	45	—	—	8,685	—	—	—	—	8,730
Acquired treasury stock	—	—	—	—	—	—	—	(78)	(32)	(32)
Comprehensive income:										
Net income	—	—	—	—	—	—	2,367	—	—	2,367
Hedge activity	—	—	—	—	—	(1,512)	—	—	—	(1,512)
Total comprehensive income	—	—	—	—	—	—	—	—	—	855
December 31, 2003	28,407	$284	—	$—	$172,532	$(5,707)	$(90,232)	$(389)	$(1,937)	$74,940

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	2002	2001
	(Amounts in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 2,367	$(38,484)	$ (30,945)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	38,501	43,291	45,106
Gain on interest rate swap	(520)	(2,248)	(332)
Loss (gain) on commodity hedges	(985)	9,050	(4,767)
Mining venture	—	—	729
Cumulative effect of a change in accounting method, net of deferred tax	1,736	—	2,767
Amortization of stock options	—	102	799
Amortization of deferred financing costs and bond premium	2,160	2,794	1,877
Loss on asset retirement obligation	18	—	—
Gain on extinguishment of debt	(23,476)	—	—
Asset retirement accretion expense	1,263	—	—
Loss on sale of assets	—	—	11,600
Impairment expense	—	16,679	27,057
Other	(285)	553	455
Deferred taxes	2,082	(10,846)	(9,650)
Changes in assets and liabilities, net of acquisition:			
Accounts receivable and accrued revenues	4,188	4,364	5,669
Prepaid expenses and other	(272)	2,473	(3,025)
Accounts payable and accrued liabilities	(4,248)	(17,913)	(5,611)
Abandonment costs	(3,550)	(2,593)	(1,371)
Other	(90)	—	—
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	18,889	7,222	40,358
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and gas properties	(1,570)	(850)	(24,159)
Acquisitions of Bargo oil and gas properties	—	—	(142,028)
Proceeds on sale of oil and gas properties, net	28,090	60,396	15,868
Proceeds on sale of other assets, net	850	—	15,668
Additions to oil and gas properties	(32,893)	(20,589)	(48,040)
Additions to gas plant facilities	—	—	(1,047)
Additions to leasehold, furniture and equipment	(930)	(198)	(527)
NET CASH FLOWS PROVIDED BY (USED IN) INVESTING ACTIVITIES	(6,453)	38,759	(184,265)

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

	Year Ended December 31,		
	2003	2002	2001
	(Amounts in thousands)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	80,000	21,000	208,754
Net proceeds from issuance of common stock	4	—	899
Bond purchase	(71,700)	—	—
Payments of long-term debt	—	(56,000)	(199,204)
Proceeds from issuance of senior subordinated notes due 2007, including premium	—	—	126,875
Cash held for reinvestment	(24,877)	—	—
Credit facility costs	(4,976)	(237)	(7,278)
NET CASH FLOWS (USED IN) PROVIDED BY FINANCING ACTIVITIES	(21,549)	(35,237)	130,046
Net increase (decrease) in cash and cash equivalents	(9,113)	10,744	(13,861)
Cash and cash equivalents at beginning of period	11,347	603	14,464
Cash and cash equivalents at end of period	$ 2,234	$ 11,347	$ 603

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Mission Resources Corporation (the "Company" or "Mission") is an independent oil and gas exploration and production company. We develop and produce crude oil and natural gas. Mission's balanced portfolio comprises assets located in the Permian Basin (West Texas and Southeast New Mexico), along the Texas and Louisiana Gulf Coast and in the Gulf of Mexico. Our operational focus is on property enhancement through development drilling, operating cost reduction, low to moderate risk exploration, asset redeployment and acquisitions of properties in the right circumstances.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Mission Resources Corporation and its wholly owned subsidiaries. Mission owns a 26.6% interest in the White Shoal Pipeline Corporation that is accounted for using the equity method. Mission's investment of approximately $362,000 at December 31, 2003 is included in the other assets line of the Consolidated Balance Sheet. Mission has not received any distributions from White Shoal Pipeline Corporation. Mission had a 10.1% ownership in the East Texas Salt Water Disposal Company that was accounted for using the cost method. It was reported at $861,000 in the other assets line of the Consolidated Balance Sheet at December 31, 2002. This interest was sold in December 2003 in connection with the sale of several oil and gas properties in the East Texas area.

In 1999, the Company invested in a Canadian company ("Carpatsky") that had the right to produce and sell oil and gas from two fields in the Ukraine. Due to different business and cultural approaches, foreign regulations and financial limitations, the Company did not have significant influence over Carpatsky; therefore the investment in Carpatsky was reflected using the cost method. In June 2001, the Company exchanged its interests in Carpatsky for a production payment on Carpatsky's producing properties, reporting $6.2 million as a long-term receivable. In the fourth quarter of 2001, due to increased uncertainties in world markets and declining commodity prices and uncertainties related to the collectibility of the receivable, it was charged to expense as part of the impairments line on the Consolidated Statement of Operations.

Oil and Gas Properties

Full Cost Pool — The Company utilizes the full cost method to account for its investment in oil and gas properties. Under this method, all costs of acquisition, exploration and development of oil and gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs and tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and gas properties when incurred. Direct internal costs that are capitalized are primarily the salary and benefits of geologists and engineers directly involved in acquisition, exploration and development activities, and amounted to $1.8 million, $1.3 million, and $3.2 million in the years ended December 31, 2003, 2002 and 2001, respectively. Until June 2001, the Company had two full cost pools: United States and Ecuador. The Company's interests in Ecuador were sold in June 2001 for gross proceeds of $8.5 million. Because the Ecuador sale involved the entire full cost pool, the book value of the pool was removed from the Consolidated Balance Sheet and the resulting $12.7 million excess of book value over proceeds was reported as part of the loss on sale of assets line of the Consolidated Statement of Operations for the year ended December 31, 2001.

Over the past several months, a reporting issue has arisen regarding the application of certain provisions of Statement of Financial Accounting Standards ("SFAS") SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. This matter has recently been taken up by the Emerging Issues Task Force. The issue is whether SFAS No. 141 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide additional specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 141 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company believes it would be required to reclassify less than $1.0 million out of oil and gas properties and into a separate intangible assets line item. These costs include those to acquire contract based drilling and mineral use rights such as delay rentals, lease bonuses, commissions and brokerage fees, and other leasehold costs. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements. The Company will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided.

Depletion — The cost of oil and gas properties, the estimated future expenditures to develop proved reserves, and estimated future abandonment, site remediation and dismantlement costs are depleted and charged to operations using the unit-of-production method based on the ratio of current production to proved oil and gas reserves as estimated by independent engineering consultants as of the beginning of the reporting period. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or whether impairment has occurred. Depletion expense per thousand cubic feet of gas equivalent ("MCFE") was approximately $1.65 in 2003, $1.29 in 2002, and $1.12 in 2001.

Unproved Property Costs — The following table shows, by category of cost and date incurred, the domestic unproved property costs excluded from amortization (amounts in thousands):

	Leasehold Costs	Exploration Costs	Total at December 31, 2003
Costs Incurred During Periods Ended:			
December 31, 2003	$ 422	$384	$ 806
December 31, 2002	1,265	—	1,265
December 31, 2001	2,706	—	2,706
December 31, 2000	132	—	132
Prior	1,214	—	1,214
	$5,739	$384	$6,123

Such unproved property costs fall into four broad categories:

- Material projects which are in the last one to two years of seismic evaluation;
- Material projects currently being marketed to third parties;
- Leasehold and seismic costs for projects not yet evaluated; and
- Drilling and completion costs for projects in progress at year-end that have not resulted in the recognition of reserves at December 31, 2003. This category of costs will transfer into the full cost pool in 2004.

Approximately $2.8 million, $2.2 million, and $1.8 million were evaluated and moved to the full cost pool in 2003, 2002 and 2001, respectively.

Sales of Properties — Dispositions of oil and gas properties held in the full cost pool are recorded as adjustments to net capitalized costs, with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas. Net proceeds from property sales of $28.1 million, $60.4 million, and $15.9 million were recorded in such manner during the years 2003, 2002, and 2001, respectively.

Impairment — To the extent that capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, exceed the discounted future net revenues of proved oil and gas reserves net of deferred taxes, such excess capitalized costs would be charged to operations as an impairment. Oil and gas prices as of December 31, 2003 were $32.47 per barrel of oil (NYMEX WTI Cushing) and $5.97 per MMBTU of gas (NYMEX Henry Hub). Such closing prices, adjusted to the wellhead to reflect adjustments for marketing, quality and heating content, were used to determine discounted future net revenues for the Company. In addition, the Company adjusted discounted future net revenues to reflect the potential impact of its commodity hedges that qualify for hedge accounting under SFAS No. 133. This adjustment was calculated by taking the difference between the closing NYMEX spot prices and the price ceiling on the Company's hedges multiplied by the hedged volumes that were included in proved reserves. This calculation resulted in a decrease in discounted future net revenues of $10.5 million because prices prevailing at December 31, 2003 were higher than most of the Company's price ceilings.

The Company's capitalized costs were not in excess of these adjusted discounted future net revenues as of December 31, 2003 and 2002; therefore no impairment was required. The Company, however, recorded an oil and gas property impairment of $20.8 million in 2001 because capitalized costs exceeded adjusted discounted future net revenues. The impairment was shown on the impairment expense line of the Consolidated Statement of Operations.

Any reference to oil and gas reserve information in the Notes to Consolidated Financial Statements is unaudited.

Gas Plants

On October 1, 2001, the Company sold its interest in the Snyder gas plant and Diamond M gas plant for gross proceeds of $11.5 million and recorded a gain of $1.1 million. The gain nets against a loss realized on the sale of the Company's Ecuadorian oil and gas assets on the loss on sale of assets line of the Consolidated Statement of Operations for the year ended December 31, 2001.

Revenue Recognition and Gas Imbalances

Revenues are recognized and accrued as production occurs. In 2001, the only customer accounting for greater than 10% of oil and gas revenues was an affiliate of Torch Energy Advisors ("Torch"). Sales to Torch were $43.3 million and were part of domestic revenues. In 2002, no one customer accounted for greater than 10% of oil and gas revenues. In 2003, sales to Shell Trading (US) Company totaled approximately $19.7 million and accounted for 21.5% of the Company's oil and gas revenues exclusive of the impact of hedges.

The Company uses the sales method of accounting for revenue. Under this method, oil and gas revenues are recorded for the amount of oil and natural gas production sold to purchasers. Gas imbalances are created, but not recorded, when the sales amount is not equal to the Company's entitled share of production. The Company's entitled share is calculated as the total or gross production of the property multiplied by the Company's decimal interest in the property. No provision is made unless the gas reserves attributable to a property have depleted to the point that there are insufficient reserves to satisfy existing imbalance positions. Then a liability or a receivable, as appropriate, is recorded equal to the net value of the imbalance. As of December 31, 2003, the Company had recorded a net liability of approximately $1.1 million, representing approximately 379,000 MCF at an average price of $2.95 per MCF, related to imbalances on properties at or nearing depletion. The net liability accrued as of December 31, 2002, was $454,000 for approximately 266,000 MCF at an average price of $1.71 per MCF. The gas imbalances were valued using the price at which the imbalance originated if there is a gas balancing agreement or the current price where there is no gas balancing agreement. Reserve reductions on any fields that have imbalances could cause this liability to increase. Settlements are typically negotiated, so the per MCF price for which imbalances are settled could differ among wells and even among owners in one well. Exclusive of the liability recorded for properties at or nearing depletion (see discussion above), the Company's remaining unrecorded imbalance, valued at current prices, would be a $1.7 million liability.

Receivables

The Company records receivables at their net realizable value using the specific write off method of accounting for receivables. Joint interest billing receivables represent those amounts due to the Company as operator of an oil and gas property by the other working interest partners. Since these partners could also be the operator of other properties in which the Company is a working interest partner, the interdependency of the partners tends to assure timely payment. Past due balances over 90 days and over $30,000 are reviewed for collectibility monthly, and charged against earnings when the potential for collection is determined to be remote. The Company has recognized bad debt expense, included in interest and other income on the Consolidated Statement of Operations, of $185,000, and $430,000 related to such receivables for the years ended December 31, 2002 and 2001, respectively. In 2003, the Company made full or partial collection of several previously written off balances for a net gain of approximately $109,000. At December 31, 2003, one partner's outstanding balance accounts for approximately 22% of the total receivable and approximately 88% of that outstanding balance is less than 45 days old. No other customers account for more than 15% of the Company's outstanding receivables. The Company does not have any off-balance sheet credit exposure related to its customers.

From time to time, certain other receivables are created and may be significant. At December 31, 2003, the Company has recorded a receivable of approximately $2.4 million from its insurance carrier, representing repair costs incurred as a direct result of hurricane Lili in 2002

A portion of the Company's November 2001 gas production was sold under contract to a subsidiary of Enron Corporation ("Enron"). Payment for that production totaling $2.2 million was due in December 2001 and was not received. Due to Enron's bankruptcy filing and continued legal difficulties, the Company chose to write off the entire amount due from Enron. A separate line for uncollectible gas revenues was added to the Consolidated Statement of Operations in order to clearly segregate the $2.2 million charge to income recognized in 2001 due to Enron's failure to make payment.

Cash Held for Reinvestment

The approximately $24.9 million shown on the Consolidated Balance Sheet as cash held for reinvestment represents the net proceeds of the oil and gas property sales that were closed during the fourth quarter of 2003. The Company's credit facility requires that sale proceeds in excess of $5.0 million be reinvested in approved replacement oil and gas properties. If no adequate replacement is found, then the sale proceeds are to be used to pay down the outstanding long-term debt. The Company did reinvest the sale proceeds by acquiring the Jalmat field in the Permian Basin on January 30, 2004.

Income Taxes

Deferred taxes are accounted for under the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of "temporary differences" by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The ultimate realization of deferred tax assets is dependent upon the recognition of future taxable income in periods when the temporary differences are available. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs.

Statements of Cash Flows

For cash flow presentation purposes, the Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. Interest paid in cash for the years ended December 31, 2003, 2002 and 2001, was $26.7 million, $26.4 million, and $19.0 million, respectively. Income taxes paid in cash, net of cash refunds, for the year ended December 31, 2001 were $2.5 million. Net cash refunds of approximately $0.5 million and $1.8 million were received in the years ended December 31, 2003 and 2002, respectively.

On December 17, 2003, the Company exchanged 4.5 million shares of its common stock, valued at the market price of $1.94 per share for purposes of recording the exchange, for $10 million aggregate principal amount of its 10⅞% senior subordinated notes due 2007. FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series were the recipients of the shares in this non-cash transaction.

A significant portion of the funding of the 2001 Bargo merger was non-cash as follows (amounts in thousands):

	Year Ended December 31, 2001
Fair value of assets and liabilities acquired:	
Net current assets and other assets	$ 2,453
Property, plant, and equipment	260,893
Goodwill and intangibles	16,601
Deferred tax liability	(56,610)
Total allocated purchase price	223,337
Less non-cash consideration — issuance of stock	80,000
Less cash acquired in transaction	1,309
Cash used for business acquisition, net of cash acquired	$142,028

Benefit Plans

During 1993, the Company adopted the Mission Resources Simplified Employee Pension Plan (the "Savings Plan") whereby all employees of the Company are eligible to participate. The Savings Plan is administered by a Plan Administrator appointed by the Company. Eligible employees may contribute a portion of their annual compensation up to the legal maximum established by the Internal Revenue Service for each plan year. The Company matches contributions up to a maximum of 6% each plan year. Employee contributions are immediately vested and employer contributions have a four-year vesting period.

Amounts contributed by the Company to the Savings Plan for the years ended December 31, 2003, 2002 and 2001 were approximately $335,000, $96,000, and $405,000, respectively.

Deferred Compensation Plan

In late 1997, the Company adopted the Mission Deferred Compensation Plan. This plan allowed selected employees the option to defer a portion of their compensation until their retirement or termination. Such deferred compensation was invested in any one or more of six mutual funds managed by a fund manager at the direction of the employees. The market value of these investments is included in current assets at December 31, 2002 and 2001 and was approximately $419,000, and $124,000, respectively. An equivalent liability due to the plan participants is included in current liabilities. In June 2003, the Company terminated the Mission Deferred Compensation Plan, and the fund manager made final distributions of all funds held in the plan to the plan participants. Both the current asset and the current liability of approximately $111,000 related to the plan at the termination date were removed from the Balance Sheet.

Stock-Based Employee Compensation Plans

At December 31, 2003, the Company had two stock-based employee compensation plans, which are described more fully in Note 5. The Company accounts for those plans under the recognition and measurement principles of APB Opinion No. 25, *Accounting for Stock Issued to Employees,* and related Interpretations. No stock-based employee compensation cost is reflected in net income for options granted under those plans with an exercise price equal to the market value of the underlying common stock on the date of the grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of FASB Statement No. 123, *Accounting for Stock-Based Compensation,* to stock-based employee compensation (amounts in thousands, except per share amounts).

	Year Ended December 31,		
	2003	2002	2001
Net income (loss)			
As reported	$2,367	$(38,484)	$(30,945)
Pro forma	$ 729	$(39,315)	$(35,007)
Earnings (loss) per share			
As reported	$ 0.10	$ (1.63)	$ (1.54)
Pro forma	$ 0.03	$ (1.67)	$ (1.75)
Diluted earnings (loss) per share share			
As reported	$ 0.10	$ (1.63)	$ (1.54)
Pro forma	$ 0.03	$ (1.67)	$ (1.75)

Mining Venture

During fiscal year 1992, Mission acquired an average 24.4% interest in three mining ventures (the "Mining Venture") from an unaffiliated individual for $128,500. At the time of such acquisition, J. P. Bryan, a member of the Mission Board of Directors until October 2002, his brother, Shelby Bryan and Robert L. Gerry III (the "Affiliated Group"), owned an average 21.5% interest in the Mining Venture. Mission's interest in the Mining Venture increased as it paid costs of the venture while the interest of the Affiliated Group decreased. Through December 31, 2001, Mission spent an additional $185,000 primarily for soil evaluations. These exploratory costs, plus $729,000, were charged to earnings in 2001. Under existing agreements Mission is not required to pay any additional mining venture costs. Should Mission choose to pay any additional costs, they will be charged directly against income as incurred.

Goodwill

SFAS No. 142, *Goodwill and Other Intangible Assets* was approved in June 2001. This pronouncement requires that intangible assets with indefinite lives, including goodwill, cease being amortized and be evaluated on an annual basis for impairment. The Company adopted SFAS No. 142 on January 1, 2002 at which time the Company had unamortized goodwill, related to the Bargo merger, in the amount of $15.1 million and unamortized identifiable intangible assets in the amount of $374,300, all subject to the transition provisions. Upon adoption of SFAS No. 142, $277,000 of workforce intangible assets recorded as unamortized identifiable assets was subsumed into goodwill and was not amortized as it no longer qualified as a recognizable intangible asset.

The transition and impairment test for goodwill, effective January 1, 2002, was performed in the second quarter of 2002. As of January 1, 2002, the Company's fair value exceeded the carrying amount therefore goodwill was not impaired. Mission designated December 31st as the date for its annual test. Based upon the results of such test at December 31, 2002, goodwill was fully impaired and a write-down of $16.7 million was recorded. The valuation was based on the following procedures and information:

- computed cash flow model of the Company's oil and gas assets using third party information and verification;
- applied risking parameters to the various categories of oil and gas reserves using reputable third party sources for risk profile;
- applied a discount rate to such valuation that approximates Mission's cost of capital and cost of debt;
- reduced the valuation by Mission's net debt to ascertain the equity fair value; and
- compared book equity to fair value equity.

The changes in the carrying amount of goodwill for the period ended December 31, 2002, are as follows (amounts in thousands):

	Goodwill	Intangible Assets	Total Goodwill *and Intangibles*
Balance, December 31, 2001	$15,061	$375	$15,436
Transferred to goodwill	277	(277)	—
Amortization of lease	—	(98)	(98)
Merger purchase price allocation adjustments	1,341	—	1,341
Goodwill impairment	(16,679)	—	(16,679)
Balance, December 31, 2002	$ —	$ —	$ —

SFAS No. 142 requires disclosure of what reported income before extraordinary items and net income would have been in all periods presented exclusive of amortization expense (including any related tax effects) recognized in those periods related: 1) to goodwill, 2) to intangible assets that are no longer being amortized, 3) to any deferred credit related to excess over cost 4) equity method goodwill, and 5) to changes in amortization periods for intangible assets that will continue to be amortized (including related tax effects). Similarly adjusted per share amounts are also required to be disclosed for all periods presented. The following table presents the required disclosures concerning adjusted income for the year ended December 31, 2001 (amounts in thousands, except per share amounts):

	Year Ended December 31, 2001
Net income (loss)	$(30,945)
Exclude goodwill amortization	986
Net income (loss) exclusive of amortization	$(29,959)
Net income (loss) exclusive of amortization per share	$ (1.49)
Net income (loss) exclusive of amortization per share — diluted	$ (1.49)

Comprehensive Income

Comprehensive income includes all changes in a company's equity except those resulting from investments by owners and distributions to owners. The accumulated balance of other comprehensive income related to cash flow hedges, net of taxes, is as follows (in thousands):

Balance at January 1, 2001	$ —
Cumulative effect of a change in accounting method	(19,328)
Net gains on cash flow hedges	13,919
Reclassification adjustments	14,934
Tax effect on hedge activity	(7,239)
Balance at December 31, 2001	2,286
Net gains (losses) on cash flow hedges	(341)
Reclassification adjustments	(8,323)
Tax effect on hedge activity	2,183
Balance at December 31, 2002	(4,195)
Net gains (losses) on cash flow hedges	(15,755)
Reclassification adjustments	15,115
Tax effect on hedge activity	(748)
Balance at December 31, 2003	$ (5,583)

Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Accounting for qualified hedges allows a derivative's gains and losses to offset related results on the hedged item in the Consolidated Statement of Operations. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in Other Comprehensive Income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based upon the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in earnings.

Asset Retirement Obligations

In July 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations,* which provided accounting requirements for retirement obligations associated with tangible long-lived assets. SFAS No. 143 requires that the Company record a liability for the fair value of its asset retirement obligation, primarily comprised of its plugging and abandonment liabilities, in the period in which it is incurred if a reasonable estimate of fair value can be made. The liability is accreted at the end of each period through charges to operating expense. The amount of the asset retirement cost is added to the carrying amount of the related asset and this additional carrying amount is depreciated over the life of the asset.

The Company adopted the provisions of SFAS No. 143 with a calculation effective January 1, 2003. The Company's assets are primarily working interests in producing oil and gas properties and related support facilities. The life of these assets is generally determined by the estimation of the quantity of oil or gas reserves available for production and the amount of time such production should require. The cost of retiring such assets, the asset retirement obligation, is typically referred to as abandonment costs. The Company hired independent engineers to provide estimates of current abandonment costs on all its properties, applied valuation techniques appropriate under SFAS No. 143, and recorded a net initial asset retirement obligation of $44.3 million on its Consolidated Balance Sheet. An asset retirement cost of $14.4 million was simultaneously capitalized in the oil and gas properties section of the Consolidated Balance Sheet. The adoption of SFAS No. 143 was accounted for as a change in accounting principle. A $1.7 million charge, net of a $935,000 deferred tax, was recorded to income as a cumulative effect of the change in accounting principle.

The following table shows changes in the asset retirement obligation that have occurred in 2003.

Asset Retirement Obligation	Year Ended December 31, 2003
	(In thousands)
Initial implementation	$44,266
Liabilities incurred	698
Liabilities settled	(9,444)
Changes in estimates	(3,466)
Accretion expense	1,263
Ending balance	33,317
Less: current portion	(1,160)
Long-term portion	$32,157

The following table summarizes pro forma net income (loss) and net income (loss) per common share as if the Company had applied the provisions of SFAS No. 143 on January 1, 2001 (amounts in thousands, except per share amounts).

	Year Ended December 31,	
	2002	2001
Net income (loss)		
As reported	$(38,484)	$(30,945)
Pro forma	$(39,632)	$(32,156)
Earnings (loss) per share		
As reported	$ (1.63)	$ (1.54)
Pro forma	$ (1.68)	$ (1.60)
Diluted earnings (loss) per share		
As reported	$ (1.63)	$ (1.54)
Pro forma	$ (1.68)	$ (1.60)

Had the Company applied the provisions of SFAS No. 143 on January 1, 2001, the Company's asset retirement obligation liabilities as of December 31, 2002 and 2001 would have been $40.3 million and $36.2 million, respectively.

New Accounting Pronouncements

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statements No. 13 and Technical Corrections,* was issued in April 2002. SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishments of debt to prohibit the classification of the gain or loss as extraordinary, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provision of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. The provisions of Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002. Mission applied the provisions of SFAS No. 145 as they relate to the extinguishment of debt in accounting for the March 28, 2003 senior subordinated note repurchase and the December 17, 2003 debt for equity swap which are further discussed in the notes to consolidated financial statements at footnote 8.

SFAS No. 146, *Accounting for Exit or Disposal Activities,* was issued in June 2002. SFAS No. 146 addresses significant issues regarding the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, *Liability Recognition of Certain Employee Termination Benefits and Other Costs to Exit an Activity.* SFAS No. 146 is effective for the exit and disposal activities initiated after December 31, 2002. The Company applied SFAS No. 146 to the closings its offices located in Longview, Texas and Belleville, Texas. The fields served by these offices were sold during the fourth quarter of 2003. All activities required to close the offices and to establish one replacement office nearer to the Company's remaining operated properties were concluded during 2003. An aggregate loss of approximately $136,000 was recognized in connection with these office closings, with almost $122,000 of the total related to severance payments made in accordance with Mission's existing severance plan. This loss is included in the interest and other income line of the Statement of Operations.

In November 2002, FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of*

FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34. This interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the interpretation are applicable to guarantees issued or modified after December 31, 2002 and did not materially affect our financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 15, 2002 and can be found in the notes to consolidated financial statements at footnote 12.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment of SFAS No. 123,* that provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements. Some of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in these notes to consolidated financial statements at footnotes 2 and 5.

FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of APB No. 51*, in January 2003. This interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the interpretation. The interpretation applies immediately to variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. The Company does not own an interest in any variable interest entities; therefore, this interpretation is not expected to have a material effect on its financial statements.. The provisions of this interpretation will be applied in the future should Mission acquire or establish a variable interest entity.

SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* was issued in April 2003. This statement amends and clarifies the accounting and reporting for derivative instruments, including embedded derivatives, and for hedging activities under SFAS No. 133. Statement 149 amends SFAS 133 to reflect the decisions made as part of the Derivatives Implementation Group (DIG) and in other FASB projects or deliberations. SFAS 149 is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The Company has addressed the pertinent DIG interpretations as they were issued and does not expect that SFAS No. 149 will have a material impact on the Company's financial statements.

SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* was issued in May 2003. SFAS No. 150 provides guidance on how to classify and measure certain financial instruments with characteristics of both liabilities and equity. Many of these instruments were previously classified as equity. This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The statement requires cumulative effect transition for financial instruments existing at adoption date. None of the Company's financial instruments were impacted by this statement.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities as well as reserve information which affects the depletion calculation and the computation of the full cost ceiling limitation to prepare these financial statements in conformity with generally accepted accounting principles in the United States. Actual results could differ from these estimates.

Reclassifications

Certain reclassifications of prior period statements have been made to conform to current reporting practices.

3. Acquisitions and Investments

During the last three fiscal years, the Company has completed or made the following significant acquisitions and investments:

In 2003 spending for oil and gas property acquisitions was approximately $1.5 million. The most significant individual acquisition was that of an additional 13.6% interest in High Island 553 for approximately $621,000. We did not make any significant oil and gas property acquisitions during 2002.

On May 17, 2001, the Company purchased oil and gas properties in south Louisiana for a gross sales price of $21.5 million.

On May 16, 2001, Bellwether Exploration Company merged with Bargo Energy Company ("Bargo") and changed its name to Mission Resources Corporation. Under the merger agreement, Bargo shareholders and option holders received a combination of cash and Mission common stock. The merger was accounted for using the purchase method of accounting and was financed through the issuance of $80.0 million, or 9.5 million shares, of Mission common stock to Bargo option holders and shareholders, and an initial $166.0 million in borrowings under a new credit facility ("Credit Facility"). Borrowings under the Credit Facility were used as follows:

- to pay the cash portion of the purchase price to holders of Bargo common stock and options;
- to pay the amount incurred by Bargo in redeeming its preferred stock immediately prior to the merger;
- to refinance Bargo's and Bellwether's then-existing credit facilities; and
- to pay transaction costs.

Initially, the $280.9 million adjusted purchase price allocated to the acquired assets was $4.1 million to unproved properties, $255.7 million to proved properties, $1.1 million to current drilling projects, $17.7 million to goodwill and intangible assets and $2.3 million to current assets, current liabilities and other non-current assets. The Company also acquired a 10.1% ownership in the East Texas Salt Water Disposal Company.

4. Related Party Transactions

Mr. J. P. Bryan, a member of Mission's board of directors until October 2002, was Chairman and CEO of Mission from August 1999 through May 2000. Mr. Bryan is also Senior Managing Director of Torch Energy Advisors ("Torch") and owns shares representing 79.5% of the shares of Torch on a fully diluted basis. Over the past three years Torch has performed services for Mission under various contracts. The nature of services and amounts of the fees paid to Torch are summarized in the following table (amounts in thousands).

	Years Ended December 31,		
	2003	2002	2001
Oil and gas marketing(1)	$88	$ 343	$ 417
Oil and gas property operations(1)	75	1,400	1,500
Snyder gas plant operations(2)	—	—	74
Acquisition and due diligence consulting	—	—	685
Contract termination fee: oil and gas property operations	75	—	—
Contract termination fee: corporate services	—	—	620

(1) Mission formed its own operations and marketing teams which began performing these functions in early 2003.

(2) The Snyder gas plant was sold in 2001.

Mission currently uses an Oracle platform provided by P2 Energy Solutions under a July 2002 hosting agreement. Torch owns 22.2% of P2 Energy Solutions as the result of a January 15, 2003 merger of its Novistar subsidiary with Paradigm Technologies, a Petroleum Place company, that created P2 Energy Solutions. Mission paid hosting fees of $667,000 and $373,000 in the years ended December 31, 2003 and 2002, respectively.

Additionally, sales of oil or natural gas to Torch accounted for approximately 32% of Mission's fiscal year 2001 oil and gas revenues. Sales to Torch were not significant in either of fiscal 2003 or 2002.

In July 2002, Mission sold interests in several properties located in New Mexico to Chisos, LTD ("Chisos"). J.P. Bryan is the President and sole owner of Chisos. The $4.0 million bid from Chisos exceeded the highest of the three other bids by $250,000 and provided Mission a non-competition agreement in New Mexico, a one-year right to participate in developmental drilling and a one-year right to participate in any preferential rights events. These considerations were not offered to Mission by any other bidder.

A $250,000 payment under a non-compete agreement was paid in the second quarter of 2002 to Tim J. Goff, Bargo's former Chief Executive Officer and former member of Mission's board of directors.

In connection with the reorganization of the Mission's management team in 2002, the Company entered into separation agreements with each of Douglas G. Manner, Jonathan M. Clarkson, and Daniel P. Foley, on July 31, 2002, September 20, 2002, and November 15, 2002, respectively. Messrs. Manner, Clarkson and Foley were previously employed by the Company pursuant to employment agreements that provided for the payment of severance upon separation from the Company based on multiples of their current salary at the time of separation. The Company negotiated severance payments for each of Messrs. Manner, Clarkson and Foley that were considerably less than the amounts provided under their respective employment agreements. Under the terms of the separation agreements, the Company paid Messrs. Manner, Clarkson and Foley total payments of $1.3 million, $1.5 million and $450,000, respectively. Of the total $3.3 million, $250,000 was deferred and was amortized to expense over the term of the consulting contract and the remainder was charged to general and administrative expenses in 2002. Messrs. Manner, Clarkson and Foley also surrendered all of their options or rights to acquire the

Company's securities. In addition, the Company agreed to provide Messrs. Manner and Clarkson with certain insurance benefits for up to 24 months after the separation date, and, to the extent the coverage or benefits received are taxable to either of Messrs. Manner or Clarkson, the Company agreed to make them "whole" on a net after-tax basis. Messrs. Manner and Clarkson also agreed to provide certain consulting services to the Company following their separation dates. In January 2003, Mr. Manner received a pay out in the sum of $314,852 from the Company's Deferred Compensation Plan made up primarily of deferred salary and bonuses under the terms of the plan

5. Stockholders' Equity

Common and Preferred Stock

The Certificate of Incorporation of the Company initially authorized the issuance of up to 30,000,000 shares of common stock and 1,000,000 shares of preferred stock, the terms, preferences, rights and restrictions of which are established by the Board of Directors of the Company. In May 2001, the number of authorized shares was increased to 60 million shares of common stock and 5 million shares of preferred stock.

Certain restrictions contained in the Company's loan agreements limit the amount of dividends that may be declared. There is no present plan to pay cash dividends on common stock as the Company intends to reinvest its cash flows for continued growth of the Company.

A tax benefit related to the exercise of employee stock options of approximately $6,000 in 2003 and $240,000 in 2001 was allocated directly to additional paid in capital. Such benefit was not material in 2002.

On December 17, 2003, the Company entered into a purchase and sale agreement with FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series providing for the issuance of 4.5 million shares of our common stock in exchange for the surrender by the Franklin entities of $10.0 million aggregate principal amount of our 10⅞% senior subordinated notes due 2007. Accrued interest on the notes to the date of the agreement will be paid on April 1, 2004, the regularly scheduled interest payment date for the notes, or upon the occurrence of certain other events

On May 16, 2001, Bellwether merged with Bargo Energy Company ("Bargo"). The resulting company was renamed Mission Resources Corporation. As partial consideration in the merger, 9.5 million shares of Mission common stock were issued to the holders of Bargo common stock and options. The $80.0 million assigned value of such shares was included in the purchase price. Concurrent with the merger, all Bellwether employees who held stock options were immediately vested in those options upon closing of the merger. Related to those options, an additional $102,000 and $799,000 of compensation expense was recognized in the years ended December 31, 2002 and 2001, respectively, as a result of staff reductions. The expense was calculated as the excess of the stock price on the merger date over the exercise price of the option.

Shareholder Rights Plan

In September 1997, the Company adopted a shareholder rights plan to protect Mission's shareholders from coercive or unfair takeover tactics. Under the shareholder rights plan, each outstanding share of Mission's common stock and each share of subsequently issued Mission common stock has attached to it one right. The rights become exercisable if a person or group acquires or announces an intention to acquire beneficial ownership of 15% or more of the outstanding shares of common stock without the prior consent of the Company. When the rights become exercisable each holder of a right will have the right to receive, upon exercise of the right, a number of shares of common stock of the Company which, at the time the rights become exercisable, have a market price of two times the exercise price of the right. The Company may redeem the rights for $.01 per right at any time before they become exercisable without shareholder approval. The rights will expire on September 26, 2007, subject to earlier redemption by the board of directors of the Company.

Earnings Per Share

The following represents the reconciliation of the numerator (income) and denominator (shares) of the earnings per share computation to the numerator and denominator of the diluted earnings per share computation (amounts in thousands, except per share amounts):

	Year Ended December 31, 2003			Year Ended December 31, 2002		
	Income	Shares	Per Share	Income	Shares	Per Share
Net income (loss)	$2,367			$(38,484)		
Earnings (loss) per common share	2,367	23,696	$0.10	(38,484)	23,586	$(1.63)
Effect of dilutive securities:						
Options & warrants	—	1,041	—	—	—	
Earnings (loss) per common share — diluted	2,367	24,737	$0.10	$(38,484)	23,586	$(1.63)

	Year Ended December 31, 2001		
	Income	Shares	Per Share
Net income (loss)	$(30,945)		
Loss per common share	(30,945)	20,051	$(1.54)
Effect of dilutive securities:			
Options & warrants	—	—	
Loss per common share — diluted	$(30,945)	20,051	$(1.54)

Potentially dilutive options and warrants that are not in the money are excluded from the computation of diluted earnings per share because to do so would be antidilutive. For the years ended December 31, 2003, 2002 and 2001, the potentially dilutive options and warrants excluded represented 1,171,500, 1,050,500 and 2,247,000 shares, respectively.

In periods of loss, the effect of potentially dilutive options and warrants that are in the money are excluded from the calculation of diluted earnings per share. For the years ended December 31, 2002 and 2001, potential incremental shares of 250,000 and 190,000, respectively, were excluded.

Treasury Stock

In September 1998, the Company's Board of Directors authorized the repurchase of up to $5.0 million of the Company's common stock. As of December 31, 2002, 311,000 shares had been acquired at an aggregate price of $1.9 million. In the second quarter of 2003, the number of treasury shares increased to 389,323 because 78,323 shares were taken into treasury in lieu of collecting a note receivable valued at approximately $32,000. Treasury shares are valued at the price at which they are acquired, resulting in approximately $1.9 million being reported as a reduction to Stockholders' Equity as of December 31, 2003.

Stock Incentive Plans

On November 5, 2003, the Compensation Committee of the Board of Directors awarded Robert L. Cavnar, our Chairman of the Board, President and Chief Executive Officer, 800,000 share appreciation rights. The rights have an initial value of $0.55 for each right granted, have a term of ten years and fully vest only upon the occurrence of a "change of control" or the termination of Mr. Cavnar's employment by the Company without "cause" or by Mr. Cavnar for "good reason." Upon the occurrence of any of the foregoing vesting events, the Company will pay to Mr. Cavnar, for each right, cash in the amount of the difference between the initial value of the right and the then current price of the Company's common stock as determined by the share appreciation rights agreement. Compensation expense will be recorded for this difference at the time it becomes probable the share appreciation rights will become vested.

The Company has stock option plans that provide for granting of options for the purchase of common stock to directors, officers and employees of the Company. In May 2001, the number of shares available for issuance under the 1996 Stock Incentive Plan was increased by 2.0 million. These stock options may be granted subject to terms ranging from 6 to 10 years at a price equal to the fair market value of the stock at the date of grant. At December 31, 2003, there were 40,334 options available for grants.

A summary of activity in the stock option plans is set forth below:

		Option Price Range	
	Number of shares	Low	High
Balance at December 31, 2000	2,302,666	$3.34	$12.38
Granted	1,984,000	$5.71	$ 8.80
Surrendered	(124,500)	$4.59	$12.38
Exercised	(177,331)	$3.34	$ 7.63
Balance at December 31, 2001	3,984,835	$3.34	$12.38
Granted	2,205,000	$0.31	$ 3.28
Surrendered(1)	(2,974,335)	$2.24	$12.38
Exercised	—	—	—
Balance at December 31, 2002	3,215,500	$0.31	$10.31
Granted	977,000	$0.38	$ 2.61
Surrendered	(81,000)	$5.75	$ 7.63
Exercised	(10,000)	$0.38	$ 0.38
Balance at December 31, 2003	4,101,500	$0.31	$10.31
Exercisable at December 31, 2003	2,793,168	$0.31	$10.31

(1) In 2002, many employees voluntarily surrendered out of the money options.

Detail of stock options outstanding and options exercisable at December 31, 2003 follows:

	Outstanding			Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
1994 Plan $0.38 to $6.38	486,000	7.9	$0.93	352,668	$1.05
1996 Plan $0.31 to $10.31	3,615,500	8.3	$2.11	2,440,500	$2.80
Total	4,101,500			2,793,168	

The estimated weighted average fair value per share of options granted during 2003, 2002, and 2001 was $2.67, $0.58, and $3.15, respectively. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The Black-Scholes calculation was calculated as of yearend for 2001 and 2002, but quarterly for 2003 due to the quarterly reporting requirements of SFAS No. 148.

The following weighted-average assumptions were used for each calculation.

Period	Stock Price Volatility	Risk Free Interest Rate	Average Expected Option Life
2003 Quarter 1	128%	3.9%	10
2003 Quarter 2	168%	3.9%	10
2003 Quarter 3	102%	4.2%	10
2003 Quarter 4	86%	4.1%	10
2002 Full Year	160%	3.9%	10
2001 Full Year	69%	5.3%	10

6. Derivative Instruments and Hedging Activities

The Company produces and sells crude oil, natural gas and natural gas liquids. As a result, its operating results can be significantly affected by fluctuations in commodity prices caused by changing market forces. The Company periodically seeks to reduce its exposure to price volatility by hedging a portion of its production through swaps, options and other commodity derivative instruments. A combination of options, structured as a collar, is the Company's preferred hedge instrument because there are no up-front costs and protection is given against low prices. Such hedges assure that Mission receives NYMEX prices no lower than the price floor and no higher than the price ceiling. The Company has also entered into some commodity swaps that fix the NYMEX price to be received. Hedging activities decreased revenues by $15.8 million, $342,000 and $13.4 million for the years 2003, 2002 and 2001, respectively.

The Company's 12-month average realized price, excluding hedges, for natural gas per MCF is generally $0.19 less than the NYMEX MMBTU price. The Company's 12-month average realized price, excluding hedges, for oil is generally $0.81 per BBL less than NYMEX. Realized prices differ from NYMEX as a result of factors such as the location of the property, the heating content of natural gas and the quality of oil. The oil differential stated above excludes the impact of Point Pedernales field production for which selling price was capped at $9.00 per BBL. The Point Pedernales field was sold in March 2003. The gas differential stated above excludes the impact the Mist field gas production which is sold at an annually fixed price.

In May 2002, several existing oil collars were cancelled. New swaps and collars, hedging forecasted oil production were acquired. The Company paid approximately $3.3 million dollars to counter parties, the fair value of the oil price collars at that time, in order to cancel the transactions. The cancellation of these hedges did not have an immediate impact on income. As required by SFAS No. 133, a $418,000 amount related to the cancelled hedges had not yet been recognized in earnings. Such amount was amortized from other comprehensive income ("OCI") over the 19-month life of the cancelled hedges and has been fully amortized at December 31, 2003 to the interest and other income line of the Statement of Operations.

In October 2002, the Company elected to de-designate all existing hedges and to re-designate them by applying the interpretations from the FASB's Derivative Implementation Group issue G-20 ("DIG G-20"). The Company's previous approach to assessing ineffectiveness excluded time value which was recorded to income currently. By using the DIG G-20 approach, because the Company's collars and swaps meet specific criteria, the time value component is included in the hedge relationship and is recorded to OCI rather than income which reduces earnings variability. Both the realized and unrealized gains or losses related to these de-designated hedges at October 15, 2002 were amortized over the remaining 15 months to the interest and other income line of the Consolidated Statement of Operations and were fully amortized at December 31, 2003. Netted against this amortization was a gain of approximately $193,000 that the Company recognized in 2003 related to ineffectiveness of its cash flow hedges. As the existing hedges settle over the next two years, gains or losses in OCI will be reclassified. The amount expected to be reclassified over the next twelve months will be an $8.6 million loss.

The following tables detail the cash flow commodity hedges that were in place at December 31, 2003.

Oil Hedges

Period	BBLS Per Day	Total BBLS	Type	NYMEX Price Floor/Swap Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2004	2,500	227,500	Swap	$25.24	N/A
First Qtr. 2004	1,000	91,000	Collar	$28.00	$30.42
Second Qtr. 2004	2,500	227,500	Swap	$24.67	N/A
Third Qtr. 2004	2,500	230,000	Swap	$24.30	N/A
Fourth Qtr. 2004	2,500	230,000	Swap	$23.97	N/A

Gas Hedges

Period	MMBTU Per Day	Total MMBTU	Type	NYMEX Price Floor Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2004	15,000	1,365,000	Collar	$4.80	$6.11
Second Qtr. 2004	7,000	637,000	Collar	$3.93	$4.37
Third Qtr. 2004	7,000	644,000	Collar	$3.93	$4.34
Fourth Qtr. 2004	7,000	644,000	Collar	$4.04	$4.58
First Qtr. 2005	1,000	90,000	Collar	$4.25	$6.32
Second Qtr. 2005	1,000	91,000	Collar	$4.25	$4.92
Third Qtr. 2005	1,000	92,000	Collar	$4.25	$4.72
Fourth Qtr. 2005	1,000	92,000	Collar	$4.25	$5.14

The Company may also enter into financial instruments such as interest rate swaps to manage the impact of interest rates. Effective September 22, 1998, the Company entered into an eight and one-half year interest rate swap agreement with a notional value of $80.0 million. Under the agreement, Mission received a fixed interest rate and paid a floating interest rate. In February 2003, the interest rate swap was cancelled and the Company paid $1.3 million payment to the counter party.

7. Determination of Fair Values of Financial Instruments

Fair value for cash, short-term investments, receivables and payables approximates carrying value. The interest rate swap, the commodity derivatives and the asset retirement obligations are also reflected on the Balance Sheet at fair value. The following table details the carrying values and approximate fair values of the Company's other investments and long-term debt at December 31, 2003 and 2002 (in thousands).

	December 31, 2003		December 31, 2002	
	Carrying Value	Approximate Fair Value	Carrying Value	Approximate Fair Value
Assets (Liabilities):				
Long-term debt: (See Note 8)				
Credit Facility	$ (80,000)	$ (80,000)	$ —	$ —
Senior Subordinated Notes, excluding unamortized premium	$(117,426)	$(110,968)	$(225,000)	$(135,900)

8. Long-Term Debt

Long-term debt is comprised of the following at December 31, 2003 and 2002 (in thousands):

	December 31, 2003	December 31, 2002
Term loan facility	$ 80,000	$ —
Credit facility	—	—
$10\frac{7}{8}$% senior subordinated notes due 2007	117,426	225,000
Subtotal	197,426	225,000
Premium on senior subordinated notes due 2007	1,070	1,431
Long-term debt	$198,496	$226,431

Debt maturities by fiscal year are as follows (amounts in thousands):

2004	$ —
2005	80,000
2006	—
2007	117,426
2008	—
Thereafter	—
	$197,426

Credit Facility

The Company was party to a $150.0 million credit facility with a syndicate of lenders. The credit facility was a revolving facility, expiring May 16, 2004, which allowed Mission to borrow, repay and re-borrow under the facility from time to time. The total amount which might be borrowed under the facility was limited by the borrowing base periodically set by the lenders based on Mission's oil and gas reserves and other factors deemed relevant by the lenders. The facility was re-paid in full on March 28, 2003.

On March 28, 2003, simultaneously with the acquisition of $97.6 million of the 10⅞% senior subordinated notes, due 2007 (the "Notes") discussed below, the Company amended and restated its credit facility with new lenders, led by Farallon Energy Lending, LLC. The entire $947,000 of deferred financing costs relating to the previously existing facility was charged to earnings as a reduction in the gain on extinguishment of debt. Under the amended and restated secured credit agreement (the "Facility"), the Company borrowed $80.0 million pursuant to term loans (the "Term Loan Facility"), the proceeds of which were used to acquire approximately $97.6 million face amount of Notes, to pay accrued interest on the Notes purchased, and to pay closing costs associated therewith. On June 16, 2003, the Company amended the Facility to add a revolving credit facility of up to $12.5 million (the "Revolver Facility"), including a letter of credit sub-facility (the "Sub-Facility") of up to $3.0 million. The Term Loan Facility expires on January 6, 2005, and the Revolver Facility expires on June 6, 2006. The Facility, which includes the Term Loan Facility and the Revolver Facility, is secured by a lien on substantially all of the Company's property and the property of all of the Company's subsidiaries, including a lien on at least 90% of their respective oil and gas properties and a pledge of the capital stock of all the subsidiaries.

As of December 31, 2003, the Company had no amounts outstanding under the Revolver Facility, but has issued $100,000 of letters of credit under the Sub-Facility. The proceeds of the Revolver Facility are to be used to finance the Company's ongoing working capital and general corporate needs. Subject to the terms and conditions of the Revolver Facility, the lenders under the Revolver Facility have agreed to make advances to the Company, from time to time, prior to the maturity date of the Revolver Facility, in an amount equal to the least of the following (in whole multiples of $1,000,000):

(i) $12.5 million minus outstanding letters of credit,

(ii) the Borrowing Base (as defined below) minus outstanding letters of credit,

(iii) during a Cleanup Period (as defined below), $3.0 million minus outstanding letters of credit in excess of $1.0 million.

"Borrowing Base" means an amount equal to 10% of the PV-10 Value (as defined in the Facility) of the Company's proved developed producing reserves minus the sum of the Bank Product Reserves and Agent Reserves (each as defined in the Facility). The Borrowing Base was $13.2 million at December 31, 2003. A "Cleanup Period" shall be either of the following periods if principal amounts under the Term Loan Facility are outstanding:

(x) the 30-day period immediately following any 90-day period in which the total of advances and letters of credit outstanding under the Revolver Facility exceeded $3.0 million for each day, or

(y) the one-day period immediately following any required payment on any indebtedness subordinate to the Facility.

The interest rate on amounts outstanding under the Term Loan Facility is 12% until February 16, 2004, when it increases to 13% until the Maturity Date. The interest rate on amounts outstanding under the Revolver Facility will be equal to the prime rate plus 0.5% per annum, provided that the minimum interest rate will be 4.75% per annum. Outstanding letters of credit under the Sub-Facility will be charged a letter of credit fee equal to 3.0% per annum.

The terms of the Term Loan Facility were not materially changed in connection with the addition of the Revolver Facility and the Sub-Facility, except that the Company is required to have Excess Availability (as defined below) of $5.0 million before certain prepayments may be made on the Term Loan Facility and except for minor modifications to the Company's negative covenants relating to capital expenditures and consolidated fixed charge coverage ratio. "Excess Availability" is the amount equal to (i) the lesser of (x) $3.0 million and (y) the Borrowing Base, plus the Company's cash and cash equivalents subject to a Cash Management Agreement or a Control Agreement (each as defined in the

Facility) minus (ii) advances under the Revolver Facility plus outstanding letters of credit plus the Company's trade payables that are 45 days past due plus the amount of interest payable on the Term Loan Facility and any indebtedness subordinate to the Facility.

The Facility contains covenants that prevent the Company from making or committing to make any capital expenditures, except for capital expenditures in the ordinary course of business which:

- do not exceed the amount approved by the majority lenders for fiscal year 2004; or
- are financed out of the net cash proceeds of issuances of capital stock (effected during a 30 day period) in excess of $20.0 million or out of the net cash proceeds of asset sales, with an aggregate limit of $50.0 million during the term of the loans outstanding under the Facility (the "Loans"), (i) of up to $5.0 million during the term of the Loans, and (ii) that are paid for the acquisition of replacement assets either 90 days before or 90 days after the asset sale or recovery event.

For fiscal years 2005 and thereafter, the Company cannot make or commit to make any capital expenditures in excess of the amounts approved by the administrative agent and the majority lenders.

In addition, the Facility requires that the following financial covenants be maintained:

- minimum consolidated EBITDA, as of the last day of any fiscal quarter, for the period of two fiscal quarters that end on such day, of $17.5 million;
- maximum leverage ratio as at the last day of any fiscal quarter beginning with the fiscal quarter ending June 30, 2003, of 2.75 to 1; and
- minimum consolidated fixed charge coverage ratio, must be at least 1.00 to 1.00 at each fiscal quarter's end on a cumulative basis for the first eight fiscal quarters. Thereafter the ratio must be at least 1.25 to 1.00 at quarter's end for the total of the four preceding fiscal quarters.

Leverage ratio is defined on the last day of any fiscal quarter as the ratio of (a) the principal amount of the Loans plus the principal amount of all indebtedness that is equal to or senior in right of payment to the Loans to (b) consolidated EBITDA for the period of four quarters ending on such day. Consolidated fixed charge coverage ratio for any period, is the ratio of: (a) the consolidated EBITDA during such period plus, for each applicable test period ended on March 31, June 30, September 30, and December 31, of calendar years 2003 and 2004, $12,000,000 to (b) the sum of (i) the Company's capital expenditures during such period plus (ii) the Company's cash income tax expense for such period plus (iii) the Company's cash consolidated interest expense for such period to the extent paid or required to be paid during such period.

The Facility contains additional covenants that limit Mission's ability, among other things, to incur additional indebtedness or to create or incur liens; to merge, consolidate, liquidate, wind-up or dissolve; to dispose of property; and to pay dividends on or redeem stock. As of December 31, 2003, the Company was in compliance with the covenants in the Facility.

Senior Subordinated Notes

In April 1997, the Company issued $100.0 million of 10⅞% senior subordinated notes due 2007. On May 29, 2001, the Company issued an additional $125.0 million of senior subordinated notes due 2007 with identical terms to the notes issued in April 1997 (collectively the "Notes") at a premium of $1.9 million. The premium is amortized as a reduction of interest expense over the life of the Notes so that the effective interest rate on these additional Notes is 10.5%. The premium is shown separately on the Balance Sheet. Interest on the Notes is payable semi-annually on April 1 and October 1. The Notes are redeemable, in whole or in part, at the option of the Company beginning April 1, 2002 at 105.44%, and decreasing annually to 100.00% on April 1, 2005 and thereafter, plus accrued and unpaid interest. In the event of a change of control of the Company, as defined in the indenture, each holder of the Notes will have the right to require the Company to repurchase all or part of such holder's Notes at an offer price in cash equal to 101.0% of the aggregate principal amount thereof, plus accrued and unpaid interest to the date of purchase. The Notes contain certain covenants, including limitations on indebtedness, liens, compliance with requirements of existing indebtedness, dividends, repurchases of capital stock and other payment restrictions affecting restricted subsidiaries, issuance and sales of restricted subsidiary stock, dispositions of proceeds of asset sales and restrictions on mergers and consolidations or sales of assets. As of December 31, 2003, the Company was in compliance with its covenants under the Notes.

On March 28, 2003, the Company acquired, in a private transaction with various funds affiliated with Farallon Capital Management, LLC, pursuant to the terms of a purchase and sale agreement, approximately $97.6 million in principal amount of the Notes for approximately $71.7 million, plus accrued interest. Immediately after the consummation of the purchase and sale agreement, Mission had $127.4 million in principal amount of Notes outstanding. Including costs of the transaction and the removal of $2.2 million of previously deferred financing costs related to the acquired Notes, the Company recognized a $22.4 million gain on the extinguishment of the Notes.

On December 17, 2003, in a private transaction with FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series, the Company acquired $10.0 million in principal amount of the Notes in exchange for 4.5 million shares of its common stock. The stock was valued at $1.94 per share, the opening price for the transaction date. After netting out costs of the transaction and the removal of previously deferred financing costs and premium related to the acquired notes, the Company recognized a net gain on the extinguishment of the Notes of approximately $1.1 million.

9. Income Taxes

Income tax expense (benefit) is summarized as follows (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Current			
Federal	$ 146	$ (734)	$ —
State	130	—	595
Deferred			
Federal	2,082	(10,846)	(10,488)
Foreign	—	—	(300)
State	—	—	1,138
Total income tax expense (benefit)	$2,358	$(11,580)	$ (9,055)

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2003 and 2002 is as follows (in thousands):

	December 31, 2003	December 31, 2002
Net operating loss carryforwards	$ 31,958	$ 26,597
Percentage depletion carryforwards	279	279
Alternative minimum tax credit carryforwards	154	8
Tax effect of hedging activities	2,729	2,259
State income taxes	2,901	3,140
Impairment of interest in Carpatsky	2,186	2,186
Other	1,044	1,869
Gross deferred tax assets	41,251	36,338
Less valuation allowance	(5,087)	(5,326)
Deferred income tax assets	36,164	31,012
Property, plant and equipment	(53,434)	(47,958)
Deferred income tax liability	(53,434)	(47,958)
Net deferred income tax asset (liability)	$(17,270)	$(16,946)

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the recognition of future taxable income during the periods in which those temporary differences are available. Based upon projections for future state taxable income, management believes it is more likely than not that the Company will not realize its deferred tax asset related to state income taxes. In addition, management believes it is more likely than not that the Company will not realize its deferred tax asset related to the impairment of the interest in Carpatsky. Accordingly, a valuation allowance has been recorded in the amount of $5.1 million and $5.3 million for the years ending December 31, 2003 and 2002, respectively.

A tax benefit related to the cumulative effect of a change in accounting method of $0.9 million and $1.7 million has been recorded and shown as part of the cumulative effect on the consolidated statements of operations in 2003 and 2001, respectively.

A tax benefit related to the exercise of employee stock options of approximately $6,000 and $240,000 was allocated directly to additional paid-in capital in 2003 and 2001, respectively. Such benefit was not material in 2002.

Total income tax differs from the amount computed by applying the federal income tax rate to income before income taxes, minority interest, and cumulative adjustment. The reasons for the differences are as follows:

	Year Ended December 31,		
	2003	2002	2001
Statutory federal income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in tax rate resulting from:			
State income taxes, net of federal benefit	5.0%	2.0%	(1.3)%
Foreign income taxes, net of federal benefit	—	—	0.5%
Non-deductible goodwill amortization/impairment	—	(11.7)%	(0.9)%
Other	0.2%	(0.2)%	(0.1)%
Change in valuation allowance	(3.7)%	(2.0)%	(8.9)%
	36.5%	23.1%	24.3%

As previously described, on December 17, 2003, the Company issued 4.5 million shares of common stock in exchange for the surrender of $10 million of our 10⅞% senior subordinated notes due 2007. As a result of this transaction, management believes that the Company has experienced an "ownership change" as defined in Section 382 of the Internal Revenue Code, which could result in the imposition of significant limitations on the future use of the Company's existing net operating loss and tax credit carryforwards in the future. As of December 31, 2003, management believes that the limitations imposed by Section 382 will not result in the Company being unable to fully utilize it's net operating loss and tax credit carryforwards to offset future taxable income and related tax liabilities.

At December 31, 2003, the Company had federal regular tax net operating loss carryforwards of approximately $91.3 million, which will expire in future years beginning in 2009 and ending in 2022 as shown below.

	$(in thousands)
2009	$ 804
2010	96
2011	878
Thereafter	89,521
Total	$91,299

10. Commitments and Contingencies

Lease Commitments

The Company leases office space for the corporate office in downtown Houston, Texas. Small field offices are leased in Giddings, Texas and Lafayette, Louisiana. At December 31, 2003, the minimum future payments under the terms of the Company's office space operating leases are as follows:

Year Ended December 31	($ in thousands)
2004	667
2005	620
2006	622
2007	—
2008	—

Rent expense was approximately $700,000, $685,000, and $551,000 in 2003, 2002 and 2001, respectively.

Contingencies

The Company is involved in litigation relating to claims arising out of its operations in the normal course of business, including workmen's compensation claims, tort claims and contractual disputes. Some of the existing known claims against the Company are covered by insurance subject to limits of such policies and the payment of deductible amounts. Management believes that the ultimate disposition of uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

A dispute between the Minerals Management Service ("MMS") and the Company concerning the appropriate expenses to be used in calculating royalties was resolved in the third quarter of 2002. The Company agreed to pay the MMS approximately $170,000, which was less than the $1.9 million reserve previously classified as other liabilities on the Balance Sheet. The Company had reserved an amount each month assuming that the entire expense tariff being deducted could be disallowed by the MMS. The Company was able to resolve the dispute on more favorable terms, resulting in a $1.7 million gain that is included in interest and other income on the Consolidated Statement of Operations during the year ended December 31, 2002.

In early 2002, Mission settled for $98,000 Garza Energy Trust, et al. v. Coastal Oil and Gas Corporation, et al. Mission had accrued $250,000 for the judgment in 2001, but later arrived at this more favorable settlement.

The Company routinely obtains bonds to cover its obligations to plug and abandon oil and gas wells. In instances where the Company purchases or sells oil and gas properties, the parties to the transaction routinely include an agreement as to who will be responsible for plugging and abandoning any wells on the property and restoring the surface. In those cases, the Company will obtain new bonds or release old bonds regarding its plugging and abandonment exposure based on the terms of the purchase and sale agreement. However, if a party to the purchase and sale agreement defaults on its obligations to obtain a bond or otherwise plug and abandon a well or restore the surface or if that party becomes bankrupt, the landowner, and in some cases the state or federal regulatory authority, may assert that the Company is obligated to plug the well since it is in the "chain of title". The Company has been notified of such claims from landowners and the State of Louisiana and is vigorously asserting its rights under the applicable purchase and sale agreements to avoid this liability. At this time, the Company has accrued a liability for approximately $140,000 for the abandonment and cleanup of the Bayou Ferblanc field and a $379,000 liability for its proposal to settlement on abandonment issues at the West Lake Ponchartrain field.

In 1993 and 1996 the Company entered into agreements with surety companies and with Torch and Nuevo Energy Company ("Nuevo") whereby the surety companies agreed to issue such bonds to the Company, Torch and/or Nuevo. However, Torch, Nuevo and the Company agreed to be jointly and severally liable to the surety company for any liabilities arising under any bonds issued to the Company, Torch and/or Nuevo. The amount of bonds presently issued to Torch and Nuevo pursuant to these agreements is approximately $0.4 million and $34.8 million, respectively. The Company has notified the sureties that it will not be responsible for any new bonds issued to Torch or Nuevo. However, the sureties are permitted under these agreements to seek reimbursement from the Company, as well and from Torch and Nuevo, if the surety makes any payments under the bonds issued to Torch and Nuevo.

11. Restructuring

During 2001 year the Company took several steps to restructure its operations and improve its cost structure, including the reduction of staff by almost 50% and the termination of several outsourcing contracts. The $2.1 million in costs associated with these plans were paid in 2002. In the latter half of 2002, Mission's Chief Executive Officer, Chief Financial Officer and Senior Vice President-Finance, left the Company to pursue other activities. This resulted in a charge of approximately $3.3 million, which is reflected in general and administrative expenses. As a condition to the separation agreements, the Company signed agreements with the former Chief Executive Officer and the former Chief Financial Officer to provide consulting services as needed over a 12-month period, the cost of which is amortized to expense over the period.

12. Guarantees

The Company's subsidiaries, Mission E&P Limited Partnership, Mission Holdings LLC, and Black Hawk Oil Company are guarantors under the senior credit facility and the indenture for the 10⅞% senior subordinated notes.

In 1993 and 1996 the Company entered into agreements with surety companies and with Torch and Nuevo whereby the surety companies agreed to issue such bonds to the Company, Torch and/or Nuevo. However, Torch, Nuevo and the Company agreed to be jointly and severally liable to the surety company for any liabilities arising under any bonds issued to the Company, Torch and/or Nuevo. The amount of bonds presently issued to Torch and Nuevo pursuant to these agreements is approximately $0.4 million and $34.8 million, respectively. The Company has notified the sureties that it will not be responsible for any new bonds issued to Torch or Nuevo. However, the sureties are permitted under these agreements to seek reimbursement from the Company, as well and from Torch and Nuevo, if the surety makes any payments under the bonds issued to Torch and Nuevo.

13. Subsequent Events

On January 30, 2004, Mission closed the $26.6 million acquisition of the Jalmat field in the Permian Basin of New Mexico. This acquisition adds approximately 26 BCFE of proved reserves and brings its percentage of natural gas and NGLs to 59%.

On February 25, 2004, Mission acquired $15.0 million of its 10⅞% senior subordinated notes due 2007 for 6.25 million shares of the Company's common stock. The transaction was completed with Stellar Funding, Ltd., a private investment fund managed by an affiliate of Guggenheim Capital, LLC. The Company has also committed to file a registration statement on Form S-3 with the SEC to register the resale of these shares. We will recognize a gain on the extinguishment of the notes of approximately $500,000.

14. Segment Reporting

Through mid-2001, the Company's operations are concentrated primarily in three segments: exploration and production of oil and natural gas in the United States, in Ecuador and gas plants. The assets in Ecuador and two gas plants were sold in 2001. The Company did not have any separately reportable segments in the years 2002 and 2003 as its focus was domestic oil and gas exploration and production.

	Year Ended December 31,		
	2003	2002	2001
Sales to unaffiliated customers:			
Oil and gas — US	$99,357	$112,879	$131,358
Oil and gas — Ecuador	—	—	1,877
Gas plants	—	—	4,456
Total sales	99,357	112,879	137,691
Gain on extinguishment of debt	23,476	—	—
Interest and other income (expense)	1,141	(7,415)	4,386
Total revenues	123,974	105,464	142,077
Operating profit (loss) before income taxes:			
Oil and gas — US	20,013	16,768	38,549
Oil and gas — Ecuador	—	—	(1,698)
Gas plants	—	—	2,338
Gain on gas plant sale	—	—	1,124
	20,013	16,768	40,313
Unallocated corporate expenses	10,200	20,655	10,998
Gain extinguishment of debt	(23,476)	—	—
Interest expense	25,565	26,853	23,664
Asset retirement obligation accretion	1,263	—	—
Mining venture costs	—	—	914
Loss on sale of Ecuador interests	—	2,645	12,724
Impairment expense	—	16,679	27,057
Uncollectible gas revenue	—	—	2,189
Operating profit (loss) before income taxes	6,461	(50,064)	(37,233)
Identifiable assets:			
Oil and gas — US	302,128	300,719	379,738
Oil and gas — Ecuador	—	—	—
Gas plants	—	—	—
	302,128	300,719	379,738
Corporate assets and investments	52,122	41,685	68,026
Total	354,250	342,404	447,764
Capital expenditures:			
Oil and gas — US	35,393	21,439	68,048
Oil and gas — Ecuador	—	—	4,151
Gas plants	—	—	1,047
	35,393	21,439	73,246
Depreciation, depletion amortization and impairments:			
Oil and gas — US	37,880	42,656	41,895
Oil and gas — Ecuador	—	—	504
Gas plants	—	—	1,025
	$37,880	$ 42,656	$ 43,424

15. Selected Quarterly Financial Data (amounts in thousands, except per share data) (Unaudited):

	Quarter Ended			
	December 31, 2003	September 30, 2003	June 30, 2003	March 31, 2003
Revenues	$26,461	$24,241	$24,625	$48,647
Operating income (loss)	$(2,174)	$(5,841)	$(4,532)	$19,008
Net income (loss)	$(1,503)	$(3,803)	$(2,946)	$10,619
Income (loss) per common share	$ (0.06)	$ (0.16)	$ (0.13)	$ 0.45
Income (loss) per common share — diluted	$ (0.06)	$ (0.16)	$ (0.13)	$ 0.45

	Quarter Ended			
	December 31, 2002	September 30, 2002	June 30, 2002	March 31, 2002
Revenues	$ 27,327	$27,571	$28,266	$ 22,300
Operating loss	$(22,704)	$(3,735)	$(9,221)	$(14,404)
Net loss	$(20,700)	$(2,428)	$(5,993)	$ (9,363)
Loss per common share	$ (0.88)	$ (0.10)	$ (0.25)	$ (0.40)
Loss per common share — diluted	$ (0.88)	$ (0.10)	$ (0.25)	$ (0.40)

The income in the first quarter of 2003 includes the $22.4 million gain on the extinguishment of debt related to the purchase and retirement of $97.6 million principal amount 10⅞% senior subordinated notes due 2007. The loss in the quarter ended December 31, 2002 includes the impact of a $16.7 million goodwill impairment.

16. Supplemental Information — (Unaudited)

Oil and Gas Producing Activities:

Included herein is information with respect to oil and gas acquisition, exploration, development and production activities, which is based on estimates of year-end oil and gas reserve quantities and estimates of future development costs and production schedules. Reserve quantities and future production are based primarily upon reserve reports prepared by the independent petroleum engineering firms. The reserve reports for the year ended December 31, 2001 were prepared by Ryder Scott Company, Netherland Sewell & Associates, Inc., and T. J. Smith & Company, Inc. The reserve report for the years ended December 31, 2003 and 2002 were prepared by Netherland Sewell & Associates, Inc.

Estimates of future net cash flows from proved reserves of gas, oil, condensate and natural gas liquids were made in accordance with SFAS No. 69, *"Disclosures about Oil and Gas Producing Activities."* The estimates are based on prices at year-end. Estimated future cash inflows are reduced by estimated future development costs (including future abandonment and dismantlement), and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. Tax expense is calculated by applying the existing statutory tax rates, including any known future changes, to the pre-tax net cash flows, less depreciation of the tax basis of the properties and depletion allowances applicable to the gas, oil, condensate and NGL production. The impact of the net operating loss is considered in calculation of tax expense. The results of these disclosures should not be construed to represent the fair market value of the Company's oil and gas properties. A market value determination would include many additional factors including:

(1) anticipated future increases or decreases in oil and gas prices and production and development costs;

(2) an allowance for return on investment;

(3) the value of additional reserves not considered proved at the present, which may be recovered as a result of further exploration and development activities; and

(4) other business risks.

Costs Incurred (in thousands)

	Year Ended December 31,		
	2003	2002	2001
United States:			
Property acquisition:			
Proved properties*	$ 1,570	$ 850	$280,281
Unproved properties	1,269	—	4,100
Exploration	4,311	1,337	12,489
Asset retirement	10,987	—	—
Development:			
Proved developed properties	13,832	16,377	25,609
Proved undeveloped properties	13,481	2,876	6,462
	45,450	21,440	328,941
Ecuador:			
Property acquisition:			
Proved properties	—	—	249
Unproved properties	—	—	—
Development:			
Proved developed properties	—	—	3,902
Proved undeveloped properties	—	—	—
	—	—	4,151
Worldwide:			
Property acquisition:			
Proved properties	$ 1,570	850	280,530
Unproved properties	1,269	—	4,100
Exploration	4,311	1,337	12,489
Asset retirement	10,987	—	—
Development:			
Proved developed properties	13,832	16,377	29,511
Proved undeveloped properties	13,481	2,876	6,462
	$45,450	$21,440	$333,092

* 2001 total includes $56.6 million of deferred taxes related to the Bargo merger.

Capitalized costs (in thousands):

	Year Ended December 31, 2003	2002
Proved properties	$ 799,777	$ 766,975
Unproved properties	6,123	8,369
Asset retirement cost	10,987	—
Total capitalized costs	816,887	775,344
Accumulated depreciation, depletion, amortization and impairment	(514,759)	(474,625)
Net capitalized costs	$ 302,128	$ 300,719

Results of operations for producing activities (in thousands):

	Year Ended December 31, 2003	2002
Revenues from oil and gas producing activities	$99,357	$112,879
Production costs	40,515	51,987
Transportation costs	349	834
Asset retirement accretion expense	1,263	—
Income tax	6,555	5,868
Depreciation, depletion and amortization	38,501	43,291
Results of operations from producing activities (excluding corporate overhead and interest costs)	$12,174	$ 10,899

	Year Ended December 31, 2001		
	United States	Ecuador	Worldwide
Revenues from oil and gas producing activities	$131,358	$ 1,877	$133,235
Production expenses	48,134	3,071	51,205
Transportation costs	73	—	73
Income tax	6,208	—	6,208
Impairment expense	20,811	—	20,811
Depreciation, depletion and amortization	44,602	504	45,106
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 11,530	$(1,698)	$ 9,832

The Company's estimated total proved and proved developed reserves of oil and gas are as follows:

Description	Year Ended December 31, 2003 Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Proved reserves at beginning of year	22,605	2,004	81,491
Revisions of previous estimates	10	(193)	4,642
Extensions and discoveries	1,310	47	14,819
Production	(2,098)	(107)	(9,675)
Sales of reserves in-place	(8,103)	(17)	(6,692)
Purchase of reserves in-place	—	—	521
Proved reserves at end of year	13,724	1,734	85,106
Proved developed reserves —			
Beginning of year	18,581	1,869	53,708
End of year	11,502	1,642	54,204

Description	Year Ended December 31, 2002 Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Proved reserves at beginning of year	39,538	2,060	154,082
Revisions of previous estimates	(1,915)	251	(42,426)
Extensions and discoveries	227	—	537
Production	(3,157)	(266)	(12,524)
Sales of reserves in-place	(12,093)	(41)	(18,178)
Purchase of reserves in- place	5	—	—
Proved reserves at end of year	22,605	2,004	81,491
Proved developed reserves — Beginning of year	31,902	1,924	97,984
End of year	18,581	1,869	53,708

Description	Year Ended December 31, 2001 Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
United States			
Proved reserves at beginning of year	9,669	1,655	74,729
Revisions of previous estimates	(1,134)	488	(3,302)
Extensions and discoveries	2,430	80	25,126
Production	(3,140)	(163)	(17,597)
Sales of reserves in-place	(3,883)	—	(15,927)
Purchase of reserves in- place	35,596	—	91,053
Proved reserves at end of year	39,538	2,060	154,082
Proved developed reserves — Beginning of year	9,073	1,508	68,757
End of year	31,902	1,924	97,984

Description	Year Ended December 31, 2001 Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Ecuador:(1)			
Proved reserves at beginning of year	7,812	—	—
Production	(95)	—	—
Sales of reserves in-place	(7,717)	—	—
Proved reserves at end of year	—	—	—
Proved developed reserves — Beginning of year	2,135	—	—
End of year	—	—	—
Worldwide:			
Proved reserves at beginning of year	17,481	1,655	74,729
Revisions of previous estimates	(1,134)	488	(3,302)
Extensions and discoveries	2,430	80	25,126
Production	(3,235)	(163)	(17,597)
Sales of reserves in-place	(11,600)	—	(15,927)
Purchase of reserves in-place	35,596	—	91,053
Proved reserves at end of year	39,538	2,060	154,082
Proved developed reserves-Beginning of year	11,208	1,508	68,757
End of year	31,902	1,924	97,984

(1) The Company's Ecuador reserves were pursuant to a contract with the Ecuadorian government under which the Company did not own the reserves but had a contractual right to produce the reserves and receive revenues.

Discounted future net cash flows (in thousands)

The standardized measure of discounted future net cash flows and changes therein related to proved oil and gas reserves are shown below:

	Year Ended December 31, 2003	2002	2001
Future cash flow	$ 978,315	$1,075,050	$1,200,145
Future production costs	(315,850)	(405,251)	(502,083)
Future income taxes	(135,803)	(125,094)	(112,364)
Future development costs	(74,090)	(74,034)	(97,644)
Future net cash flows	452,572	470,671	488,054
10% discount factor	(177,984)	(214,843)	(192,483)
Standardized future net cash flows	$ 274,588	$ 255,828	$ 295,571

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in thousands of dollars):

	Year Ended December 31, 2003	Year Ended December 31, 2002
Standardized measure — beginning of year	$255,828	$295,571
Sales, net of production costs	(74,249)	(60,031)
Net change in prices and production costs	36,042	160,132
Net change in income taxes	(4,795)	(2,635)
Extensions, discoveries and improved recovery, net of future production and development costs	74,697	3,803
Changes in estimated future development costs	(16,740)	4,459
Development costs incurred during the period	24,283	15,870
Revisions of quantity estimates	6,243	(78,419)
Accretion of discount	25,583	29,557
Asset retirement	3,550	—
Sales of reserves in-place	(69,502)	(56,875)
Changes in production rates and other	13,648	(55,604)
Standardized measure — end of year	$274,588	$255,828

	Year Ended December 31, 2001		
	United States	Ecuador	World Wide
Standardized measure — beginning of year	$ 393,582	$ 29,510	$ 423,092
Sales, net of production costs	(83,151)	1,194	(81,957)
Purchases of reserves in-place	618,442	—	618,442
Net change in prices and production costs	(727,143)	—	(727,143)
Net change in income taxes	30,994	18,577	49,571
Extensions, discoveries and improved recovery, net of future production and development costs	62,308	—	62,308
Changes in estimated future development costs	(27,152)	—	(27,152)
Development costs incurred during the period	21,584	3,736	25,320
Revisions of quantity estimates	18,376	—	18,376
Accretion of discount	39,358	2,950	42,308
Sales of reserves in-place	(89,139)	(53,017)	(142,156)
Changes in production rates and other	37,512	(2,950)	34,562
Standardized measure — end of year	$ 295,571	$ —	$ 295,571

The discounted future cash flows above were calculated using the NYMEX WTI Cushing price for oil and the NYMEX Henry Hub price for gas that was posted for the last trading day of each year presented. Those prices were $32.47, $31.17, and $19.76 per barrel and $5.97, $4.74, and $2.73 per MMBTU, for December 31, 2003, 2002, and 2001, respectively, adjusted to the wellhead to reflect adjustments for transportation, quality and heating content. The foregoing discounted future net cash flows do not include the effects of hedging or other derivative contracts not specific to a property. Including the tax effected impact of hedging on discounted future net cash flows would have increased discounted future net cash flows by approximately $5.7 million as of December 31, 2001. Including the tax effected impact of hedging on discounted future cash flows would have decreased discounted future net cash flows by approximately $3.4 million and $7.7 million as of December 31, 2003 and 2002.

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

None.

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

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, Mission's principal executive officer ("CEO") and principal financial officer ("CFO") carried out an evaluation of the effectiveness of Mission's disclosure controls and procedures pursuant to Rule 13a-15 of the Securities and Exchange Act of 1934. Based on those evaluations, the CEO and CFO believe:

(i) that Mission's disclosure controls and procedures are designed to ensure that information required to be disclosed by Mission in the reports it files under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to Mission's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that Mission's disclosure controls and procedures are effective.

Changes in Internal Controls Over Financial Reporting

There have been no significant changes in Mission's internal controls over financial reporting during the period covered by this report that has materially affected, or are reasonably likely to materially affect, Mission's control over financial reporting.

Part III

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

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2003. Such information is incorporated herein by reference.

Item 11. ***Executive Compensation***

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2003. Such information is incorporated herein by reference.

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

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2003. Such information is incorporated herein by reference.

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

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2003. Such information is incorporated herein by reference.

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

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2003. Such information is incorporated herein by reference.

Part IV

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

(a) 1. and 2. *Financial Statements.* See index to Consolidated Financial Statements and Supplemental Information in Item 8, which information is incorporated herein by reference.

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated January 24, 2001 between the Company and Bargo Energy Company (incorporated by reference to Exhibit 2.1 to the Company's 8-K filed on January 26, 2001).
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement No. 33-76570 filed on March 17, 1994).
3.2	Certificate of Amendment to Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to the Company's Annual Report on Form 10-K filed on September 27, 1997).
3.3	Certificate of Designation, Preferences and Rights of the Series A Preferred Stock of the Company (incorporated by reference to Exhibit 3.3 to the Company's Annual Report on Form 10-K filed on September 27, 1997).
3.4	Certificate of Merger of Bargo Energy Company into the Company (incorporated by reference to Exhibit 3.4 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
3.5	Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.5 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
3.6	By-laws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Registration Statement No. 33-76570 filed on March 17, 1994).
3.7	Amendment to the Company's Bylaws adopted on November 21, 1997 (incorporated by reference to Exhibit 3.5 to the Company's Annual Report on Form 10-K filed on March 27, 1998).
3.8	Amendment to the Company's Bylaws adopted on March 27, 1998 (incorporated by reference to Exhibit 3.6 to the Company's Annual Report on Form 10-K filed on March 27, 1998).
4.1	Specimen Stock Certificate (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
4.2	Rights Agreement between the Company and American Stock Transfer & Trust Company (incorporated herein by reference to Exhibit 1 to the Company's Registration Statement on Form 8-A filed on September 19, 1997).
4.3	Amendment to Rights Agreement dated as of December 17, 2003, by and between Mission Resources Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on December 18, 2003).
4.4	Amendment to Rights Agreement dated as of February 25, 2004, by and between Mission Resources Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on February 26, 2004).
4.5	Indenture dated as of May 29, 2001 among the Company, the Subsidiary Guarantors named therein and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-4 filed on July 27, 2001).
4.6	Registration Rights Agreement dated December 17, 2003, by and among Mission Resources Corporation and FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed on December 18, 2003).

Exhibit No.	Description
4.7	Registration Rights Agreement dated February 25, 2004, by and among Mission Resources Corporation and Stellar Funding Ltd.(incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed on February 26, 2004).
10.1	1994 Stock Incentive Plan (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement No. 33-76570 filed on March 17, 1994).
10.2	1996 Stock Incentive Plan (incorporated by reference to Exhibit A to the Company's Proxy Statement on Schedule 14A filed on October 21, 1996).
10.3	Amended and Restated Credit Agreement, dated as of March 28, 2003, among Mission Resources Corporation, Farallon Energy Funding, LLC, as Arranger and Lender, Jefferies & Company, Inc., as Syndication Agent and Foothill Capital Corporation, as Administrative Agent (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K, filed April 1, 2003).
10.4	Second Amended, Restated and Consolidated Guaranty and Collateral Agreement, dated as of march 28, 2003, made by Mission Resources Corporation and certain of its Subsidiaries, in favor of Foothill Capital Corporation, as Administrative Agent (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K, filed April 1, 2003).
10.5	Second Amended and Restated Credit Agreement among Mission Resources Corporation, as Borrower, the Several Lenders from Time to Time Parties Hereto, Farallon Energy Lending, L.L.C., as Arranger Jefferies & Company, Inc., as Syndication Agent and Wells Fargo Foothill, Inc., as Administrative Agent dated as of June 5, 2003 (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K filed on June 17, 2003).
10.6	Third Amended, Restated And Consolidated Guaranty And Collateral Agreement, dated as of June 5, 2003, made by Mission Resources Corporation and certain of its Subsidiaries, in favor of Wells Fargo Foothill, Inc., as Administrative Agent (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K filed on June 17, 2003).
10.7	First Amendment to and Waiver of Second Amended and Restated Credit Agreement, dated as of June 25, 2003, among Mission Resources Corporation, the several banks and other financial institutions or entities from time to time parties to the Amendment, Farallon Energy Lending, L.L.C., as sole advisor, sole lead arranger and sole bookrunner, and Wells Fargo Foothill, Inc, as administrative agent (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed November 13, 2003).
10.8	Second Amendment, dated October 22, 2003, to the Second Amended and Restated Credit Agreement, dated as of June 5, 2003, by and among Mission Resources Corporation, the several banks and other financial institutions or entities from time to time parties thereto, Farallon Energy Lending, L.L.C., as sole advisor, sole lead arranger and sole bookrunner, Jefferies & Company, Inc., as the syndication agent, and Wells Fargo Foothill, Inc, formerly known as Foothill Capital Corporation, as administrative agent (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed November 13, 2003).
10.9	Purchase and Sale Agreement, dated as of March 28, 2003, by and between Farallon Capital Management, LLC and Mission Resources Corporation, as Administrative Agent (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K, filed April 1, 2003).
10.10	Purchase and Sale Agreement, dated as of December 17, 2003, by and among Mission Resources Corporation and FTVIPT — Franklin Income Securities Fund and Franklin Custodian Funds — Income Series (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on December 18, 2003).
10.11	Purchase and Sale Agreement, dated as of February 25, 2004, by and between Mission Resources Corporation and Stellar Funding Ltd. (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on February 26, 2004).
10.12	Employment Agreement dated August 8, 2002, between the Company and Robert L. Cavnar (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 14, 2002).

Exhibit No.	Description
10.13	Employment Agreement dated October 8, 2002, between the Company and Richard W. Piacenti (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed November 14, 2002).
10.14	Employment Agreement dated November 7, 2002, between the Company and John L. Eells (incorporated by reference to Exhibit 10.14 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
10.15	Employment Agreement dated November 6, 2002, between the Company and Joseph G. Nicknish (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
10.16	Employment Agreement effective November 4, 2003 between the Company and Marshall L. Munsell (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed on November 13, 2003).
10.17	Form of Indemnification Agreement between the Company and each of its directors and executive officers (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed November 14, 2002).
21.1	*Subsidiaries of the Company.
23.1	*Consent of KPMG LLP.
23.2	*Consent of Netherland Sewell & Associates, Inc.
23.3	*Consent of Ryder Scott Company.
23.4	*Consent of T.J. Smith & Company, Inc.
31.1	*Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2	*Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
32.1	*Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer of the Company.
32.2	*Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer of the Company.

* Filed herewith.

(b) *Reports on Form 8-K*

(i) The Company filed a Current Report on Form 8-K on October 2, 2003, relating to the sale of its East Texas properties and updating the Company's drilling progress.

(ii) The Company filed a Current Report on Form 8-K on November 13, 2003, relating to third quarter 2003 results.

(iii) The Company filed a Current Report on Form 8-K on November 20, 2003, relating to election of a board member.

(iv) The Company filed a Current Report on Form 8-K on December 11, 2003, relating to the Company's hedging arrangements.

(v) The Company filed a Current Report on Form 8-K on December 18, 2003, relating to the exchange of $10,000,000 in aggregate principal amount of the Company's 10⅞% Senior Subordinated Notes due 2007 for 4.5 million shares of the Company's common stock.

GLOSSARY OF OIL AND GAS TERMS

Terms used to describe quantities of oil and natural gas

- *BBL* — One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *BCF* — One billion cubic feet of natural gas.
- *BCFE* — One billion cubic feet of natural gas equivalent, converting oil to gas at the ratio of 1 BBL of oil to 6 MCF of gas.
- *BOE* — One barrel of oil equivalent, converting gas to oil at the ratio of 6 MCF of gas to 1 BBL of oil.
- *BTU* — British thermal unit, a measurement of the energy content of natural gas.
- *MBBL* — One thousand Bbls.
- *MCF* — One thousand cubic feet of natural gas.
- *MCFE* — One thousand cubic feet of natural gas equivalent, converting oil to gas at a ratio of 1 BBL of oil to 6 MCF of gas.
- *MMCF* — One million cubic feet of natural gas.
- MM*BTU* — One million British thermal units, a measurement of the energy content of natural gas.
- *MBOE* — One thousand BOE.
- *MMBOE* — One million BOE.

Terms used to describe the Company's interests in wells and acreage

- *Gross oil and gas wells or acres* — Gross wells or gross acres represent the total number of wells or acres in which Mission owns a working interest.
- *Net oil and gas wells or acres* — Determined by multiplying "gross" wells or acres by the working interest that Mission owns in such wells or acres represented by the underlying properties.

Terms used to assign a present value to the Company's reserves

- *Standard measure of proved reserves* — The present value, discounted at 10%, of the after-tax future net cash flows attributable to estimated net proved reserves. We calculate this amount by assuming that we will sell the oil and gas production attributable to the proved reserves estimated in the independent engineer's reserve report for the prices we received for the production on the date of the report, unless we had a contract to sell the production for a different price. We also assume that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of our proved reserves.
- D*iscounted present value* — The discounted present value of proved reserves is identical to the standardized measure, except that estimated future income taxes are not deducted in calculating future net cash flows. We disclose the discounted present value without deducting estimated income taxes to provide what we believe is a better basis for comparison of our reserves to other producers who may have different tax rates.

Terms used to classify our reserve quantities

- *Proved reserves* — The estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions.

The SEC definition of proved oil and gas reserves, per Article 4-10(a)(2) of Regulation S-X, is as follows:

> *Proved oil and gas reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.
>
> (a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
>
> (b) Reserves which can be produced economically through application of improved recovery, techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
>
> (c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

- *Proved developed reserves* — Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- *Proved undeveloped reserves* — Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Terms that describe the productive life of a property or group of properties

- *Average Reserve to Production Ratio in Years* — A measure of the productive life of an oil and gas property or a group of oil and gas properties, expressed in years. Reserve life for the years ended December 31, 2003, 2002 or 2001 equals the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

Terms used to describe the legal ownership of our oil and gas properties

- *Royalty interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the mineral on the land.

- *Working interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

- *Seismic data* — Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geo-phones that digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- *2-D seismic data* — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- *3-D seismic* — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Miscellaneous definitions

- *Infill drilling* — Infill drilling is the drilling of an additional well or additional wells in excess of those provided for by a spacing order in order to more adequately drain a reservoir.
- *Upstream oil and gas properties* — Upstream is a term used in describing operations performed before those at a point of reference. Production is an upstream operation and marketing is a downstream operation when the refinery is used as a point of reference. On a gas pipeline, gathering activities are considered to have ended when gas reaches a central point for delivery into a single line, and facilities used before this point of reference are upstream facilities used in gathering, whereas facilities employed after commingling at the central point and employed to make ultimate delivery of the gas are downstream facilities.

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.

MISSION RESOURCES CORPORATION

By: /s/ ROBERT L. CAVNAR

Robert L. Cavnar
Chairman and Chief Executive Officer

Date: March 10, 2004

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

Signatures	Title	Date
/s/ ROBERT L. CAVNAR Robert L. Cavnar	Chairman and Chief Executive Officer (principal executive officer)	March 10, 2004
/s/ RICHARD W. PIACENTI Richard W. Piacenti	Executive Vice President and Chief Financial Officer (principal financial officer)	March 10, 2004
/s/ ANN KAESERMANN Ann Kaesermann	Vice President — Accounting and Investor Relations, Chief Accounting Officer (principal accounting officer)	March 10, 2004
/s/ DAVID A.B. BROWN David A.B. Brown	Director	March 10, 2004
/s/ JOSEPH N. JAGGERS Joseph N. Jaggers	Director	March 10, 2004
/s/ ROBERT R. ROONEY Robert R. Rooney	Director	March 10, 2004
/s/ HERBERT C. WILLIAMSON Herbert C. Williamson	Director	March 10, 2004

OFFICERS

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Richard W. Piacenti
Executive Vice President and Chief Financial Officer

John (Jack) L. Eells
Senior Vice President – Exploration and Geoscience

Marshall L. Munsell
Senior Vice President – Land and Land Administration

Joseph G. Nicknish
Senior Vice President – Operations and Engineering

Lloyd W. Armstrong
Vice President – Revenue Administration

Ann M. Kaesermann
Vice President – Accounting and Investor Relations, CAO

Leslee M. Ranly
Vice President and Secretary

A. Kent Rogers
Vice President – Operations

BOARD OF DIRECTORS

David A.B. Brown
Audit Committee Chairman

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Joseph N. Jaggers
Governance / Compensation Committee Member

Robert R. Rooney
Governance / Compensation Committee Chairman
Audit Committee Member

Herbert C. Williamson III
Audit Committee Member
Governance / Compensation Member

SHAREHOLDER INFORMATION

ANNUAL MEETING

Mission shareholders are cordially invited to attend the Annual Meeting of Shareholders, which will be held on Wednesday, May 19, 2004, at 10:00 a.m. CST at the Four Seasons Hotel, 1300 Lamar, Houston, TX 77010.

INDEPENDENT PUBLIC ACCOUNTANTS

KPMG LLP
700 Louisiana
Houston, TX 77002
(713) 319-2000
www.kpmg.com

STOCK TRANSFER AGENT & REGISTRAR

Shareholders with stock transfer requirements, lost stock certificates or changes of address or stock registration should contact Mission's transfer agent for assistance.

American Stock Transfer & Trust
Shareholder Services
59 Maiden Lane
New York, NY 10038
(877) 777-0800
www.amstock.com

COMMON STOCK

The common stock of Mission Resources Corporation is traded on the Nasdaq stock exchange under the ticker symbol MSSN. Daily stock reports published in newspapers carry trading summaries for the company under "Mission Res." The following shows information regarding the price range of the Company's common stock by quarter.

MARKET PRICE

2003	1Q	2Q	3Q	4Q
High	$0.47	$1.88	$2.45	$2.99
Low	$0.22	$0.25	$1.30	$1.62

The average daily trading volume in 2003 was 316,000. At March 17, 2004, the Company had 40,267,636 shares of common stock outstanding.

Shareholders, brokers, analysts or portfolio managers who have questions or need information about the Company should call Investor Relations at (713) 495-3100.

CAUTIONARY NOTE ON FORWARD-LOOKING STATEMENTS – This annual report includes "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements are subject to certain risks trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our estimate of the sufficiency of existing capital sources, our highly leveraged capital structure, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, the operating hazards attendant to the oil and gas business, as well as other risk factors described from time to time in our documents and reports filed with the Securities and Exchange Commission. Although we believe that in making such forward-looking statements our expectations are based upon reasonable assumptions, such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. We cannot assure you that the assumptions upon which these statements are based will prove to have been correct, and we cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this annual report after the date of this annual report.

Designed and produced by Mentus, San Diego, California. www.mentus.com

2003 ANNUAL REPORT

WWW.MRCORP.COM

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