MISSION
RESOURCES

ANNUAL REPORT 2002

Performance Review

(In millions of dollars except as otherwise indicated)

Financial Review	2002	2001	2000	1999	1998
Total revenues	105.5	142.1	119.3	73.4	78.2
Net income (loss)[1]	(38.5)	(30.9)	32.2	8.8	(77.3)
Earnings (loss) per common share – diluted[2] ($ per share)	(1.63)	(1.54)	2.27	0.63	(5.50)
Discretionary cash flow*	23.5	44.7	62.6	30.8	30.4
Total assets	342.4	447.8	221.5	171.8	131.2
Long-term debt (excluding unamortized premium)	225.0	260.0	125.5	130.0	104.4
Shareholders' equity	65.4	110.2	57.0	23.3	14.5
Weighted average number of common shares outstanding – diluted	23.8	20.2	14.2	13.9	14.2

Operational Review	2002	2001	2000	1999	1998
Capital expenditures, including acquisitions[3]	21.4	276.5	88.4	56.8	40.2
Total production (MMBOE)	5.5	6.3	5.8	5.2	5.8
Average daily oil production (MBO)	9.4	9.3	6.5	5.7	6.3
Average daily gas production (MMCF)	34.3	48.2	56.0	52.0	58.4
Proved oil reserves (MMBO)	24.6	41.6	19.1	16.8	10.1
Proved gas reserves (BCF)	81.5	154.1	74.7	130.1	111.6
Total proved reserves (MMBOE)	38.2	67.3	31.6	38.5	28.7
SEC PV-10 value (pre-tax)	326.9	365.4	546.0	209.0	116.0

(1) Results for 2001 and 1998 include the effects of a non-cash, after-tax impairment of proved properties of $13.5 million and $48.4 million, respectively.
(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 impact of deferred taxes.

*Non-GAAP Disclosure Reconciliation

(Amounts in millions of dollars)

	2002	2001	2000	1999	1998
Net Income:	$(38.5)	$(30.9)	$ 32.2	$ 8.8	$(77.3)
Depreciation, depletion and amortization	43.3	45.1	32.6	23.9	39.7
Impairment expense	16.6	27.0	–	–	73.9
Amortization of stock options[1]	0.1	0.8	0.8	–	–
Gain on interest rate swap[2]	(2.2)	(0.3)	–	–	–
Loss (gain) due to hedge ineffectiveness[3]	9.0	(4.8)	–	–	–
Amortization of deferred financing costs and bond premium[2]	2.8	1.9	0.6	0.8	0.8
Write-off of impaired or uncollectable receivables[3]	0.6	0.4	–	–	–
Loss on asset sales	2.6	11.6	–	–	–
Disposition of hedges	–	–	8.7	–	–
Cumulative effect of a change in accounting method, net of deferred tax	–	2.8	–	–	–
Other	–	0.8	–	–	–
Income tax expense (benefit) – deferred	(10.8)	(9.7)	(12.3)	(2.7)	(6.7)
Discretionary Cash Flow:	$ 23.5	$ 44.7	$ 62.6	$30.8	$ 30.4

(1) Included in general and administrative expenses
(2) Included in interest expense
(3) Included in interest and other income (expense)

NOTE — Management believes that discretionary cash flow is relevant and useful information, which 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.

Abbreviations

The following abbreviations are used throughout this annual report:

MBO ..... *Thousand barrels of crude oil*
MBOD.... *Thousand barrels of oil per day*
MMBO ... *Million barrels of oil*
MCF ..... *Thousand cubic feet of natural gas*
MMCF ... *Million cubic feet of gas*
MMCFD .. *Million cubic feet of gas per day*
BCF ..... *Billion cubic feet of gas*
BOE ..... *Barrel of oil equivalent*
MBOE.... *Thousand barrels of oil equivalent*
MBOED .. *Thousand barrels of oil equivalent per day*
MMBOE .. *Million barrels of oil equivalent*
PDP...... *Proved developed producing*
PUD ..... *Proved undeveloped*
PDN ..... *Proved developed non-producing*

One barrel of oil is the energy equivalent of six MCF of natural gas.

Corporate Profile

Mission Resources Corporation (NASDAQ: MSSN) is a Houston-based independent exploration and production company that drills for, acquires, develops, and produces natural gas and crude oil in the Permian Basin of West Texas, along the Texas and Louisiana Gulf Coast and in the Gulf of Mexico.

TO OUR SHAREHOLDERS: The year ended December 31, 2002 was a challenging one for all the stakeholders of Mission Resources. Early in the year, steps were taken to lower costs, reduce debt, and strengthen the company's financial position. In August 2002 the board of directors decided to bring in a new management team to initiate and execute a recovery plan. From August through November, the new team was assembled and soon thereafter established a course and strategy for the company. Our new team's key goals in 2002 were to complete a review of every function of our company, establish the geographic and strategic scope of our operations, evaluate potential avenues to recapitalize the company and develop a tactical plan for meeting these goals.

COMPANY REVIEW

As a result of our review, we made a number of strategic and tactical decisions to gain more control of our processes by performing key functions internally instead of through outsourcing. We have begun building an in-house exploration and evaluation capability by growing our technical staff of geologists, geophysicists, and engineers who have expertise in the geographic basins we have targeted. In addition, we are utilizing our existing 3-D seismic library and continue to add to our knowledge base through reprocessing of that data as well as the acquisition and evaluation of new data. We believe that future growth in our segment of the industry is technology driven, using seismic reprocessing, new seismic shoots, reservoir simulation, and sophisticated drilling and completion techniques.

Formed New Leadership Team

Reconstituted Board With 100% Independent Directors, Other Than the Chairman

Eliminated Outsourcing Agreements

Sold Non-Strategic Properties for $ 69.5 Million

Acquired $97.6 Million of Its Subordinated Notes for $71.7 Million, Replaced Senior Bank Facility

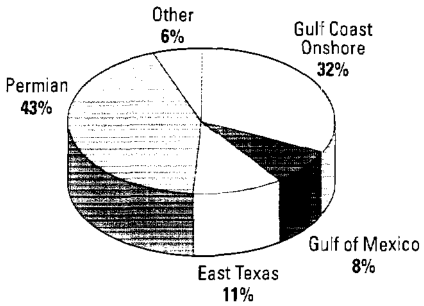
Reduced Debt by $53 Million or 20%

By the end of December 2002, we brought in-house the functions of accounting, treasury, land administration, human resources and risk management. In the first quarter of 2003, we also brought in operations and marketing and no longer outsource any functions except the contract hosting of our accounting software. By bringing all significant outsourced services in-house, we have lowered our cost structure by over $3.0 million on an annual basis.

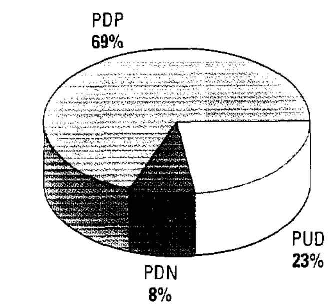
We engaged Netherland, Sewell & Associates, Inc. to perform a full evaluation of our existing reserves. Although this resulted in an 8.7 MMBOE reduction of our reserves, most of this reduction was in the proved undeveloped category. Our year end reserves were 38.2 MMBOE with 77% proved developed. We have undertaken a program to fully develop these reserves through the same technology that we are using in our exploration programs.

We place a high value on corporate governance issues that have gained focus nationally as a result of the passage of the Sarbanes-Oxley Act. During our company review we updated virtually all of our corporate governance policies to ensure we will be in compliance with the Act. Board independence was an important topic throughout 2002 and we agree that our Board should be primarily independent and governed by well-qualified directors. To this end we performed a director search in order to retain individuals of appropriate experience and independence. We were successful in this endeavor and have now reconstituted the Board with 100% independent directors, other than the Chairman, by adding David A.B. Brown and Herbert C. Williamson III. Both new directors bring industry and financial expertise to the Mission board and audit committee.

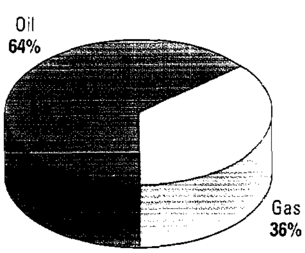
PROVED RESERVES



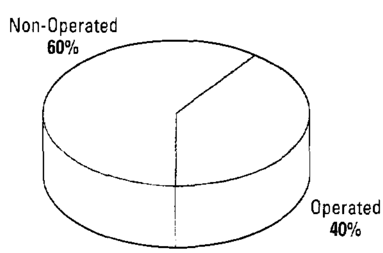
RESERVE CATEGORIES



OIL VS. GAS



OPERATED VS. NON-OPERATED



STRATEGIC DIRECTION

Our goal is to refocus the company's efforts on high rate, high return natural gas properties. The production we are targeting typically exhibits higher initial production rates, greater reserves and lower per unit costs than our current asset portfolio. Our growth program for 2003 is specifically targeting natural gas production in several producing regions: South Texas, North Louisiana and the Texas and Louisiana Gulf Coast. Concurrently, we are actively developing our existing reserves in the Permian Basin and South Louisiana. Our goal is to move our production mix toward 70% natural gas, 30% oil.

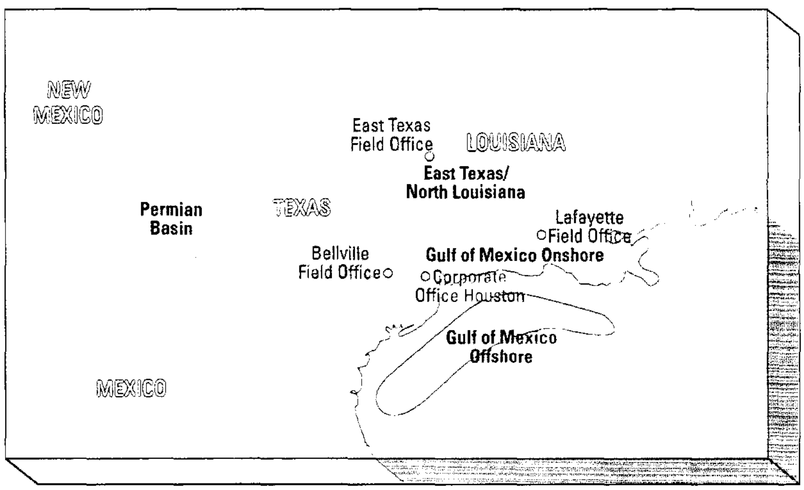
South Texas and North Louisiana represent a shift in our geographic focus. These are areas where our team is rich in experience and where we believe more attractive returns are located. To date, we have evaluated over 40 projects and have committed to drill four of these projects in 2003. We will concentrate our efforts onshore and drill with partners to mitigate reserve and mechanical risk as much as possible. We will also continue to look for acquisitions in our core areas whenever it makes sense.

In the fourth quarter, we completed a divestiture program whereby for the year we sold 15.2 MMBOE for $69.4 million. These sales enabled us to consolidate operations into our core areas and to high-grade our asset base by selling under-performing and high operating cost assets. We are continuing to review the performance of our properties and may decide to divest additional properties in order to acquire natural gas properties in South Texas and North Louisiana.

Our current 2003 capital budget is $32 million with expenditures expected to be 65% for development, 18% for exploration and 17% for land, seismic and other. We anticipate spending 55% of our capital in the Gulf Coast and South Texas regions and 23% in the Permian Basin.

CORE AREAS

Current production, after the March 2003 sale of the Point Pedernales field, is 5.9 MBOD, 24 MMCFED or 9.8 MBOED.



RECAPITALIZATION

Recovery of Mission's financial stability and value continues to be our top priority as we strive to reposition the company for growth. We completed the first step toward this goal in March 2003 by acquiring, in a private transaction, $97.6 million of the 10 7/8% senior subordinated notes due 2007 for approximately $71.7 million plus accrued interest. The transaction, net of fees, reduced our overall debt by $17.6 million and provided approximately $5.0 million for general corporate purposes. Simultaneously with the buyback, we amended and restated our credit facility with new lenders.

While we have made initial progress toward repositioning the balance sheet, we believe that further debt reduction is necessary to bring our leverage to a more appropriate level. Some of the alternatives we will be considering to reduce leverage, include, but are not limited to, a refinancing or repurchase of the remaining notes, the issuance of equity or debt securities for cash or properties or in exchange for the notes, the sale of certain oil and gas properties, the acquisition of another company or assets, the addition of other secured and unsecured debt financing, or a merger with or acquisition by another company.

WE BELIEVE THAT WE HAVE PUT TOGETHER THE RIGHT TEAM WITH THE RIGHT EXPERIENCE AND ARE LOOKING FORWARD TO MEETING THE CHALLENGES BEFORE US.

Another important goal is to protect our discretionary cash flow by hedging a percentage of our proved producing production for the current year and the two following years. Our intent is to hedge a higher percentage of our production in the current year (65% – 75%) to mitigate near-term risk, with decreasing percentages in the following two years. We may be limited in the amount of hedge transactions due to credit constraints. Preferred hedge instruments are a combination of options, structured as a collar, or price swaps. Our priority is protection from low prices with low or no up-front costs.

LOOKING FORWARD TO 2003

We have obviously been very busy since completing our team in November. We have accomplished many of our initial goals for working towards the recovery of Mission's financial condition and value. However, there is much more to do. Our 2003 objectives focus on refinancing and repositioning the balance sheet and growing our assets and discretionary cash flow through the exploration, aquisition and development of oil and gas reserves.

We believe that we have put together the right team with the right experience and are looking forward to meeting the challenges before us. We commit to you that we will continue to work hard to bring value to all the stakeholders in Mission.

Sincerely,

ROBERT L. CAVNAR
CHAIRMAN, PRESIDENT AND
CHIEF EXECUTIVE OFFICER

RICHARD W. PIACENTI
SENIOR VICE PRESIDENT AND
CHIEF FINANCIAL OFFICER

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

FORM 10-K/A

(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, 2002

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 Rule 12b-2 of the Act). Yes ☒ No ☐

The aggregate market value of the voting stock held by non-affiliates of the registrant at June 28, 2002 was approximately $25,313,355.

As of March 20, 2003, the number of outstanding shares of the registrant's common stock was 23,585,959.

Documents Incorporated by Reference: Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 2002, 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, 2002

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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.

Item 1. *Business*

General

Mission Resources Corporation is an independent oil and gas exploration and production company headquartered in Houston, Texas. We acquire, develop and produce crude oil and natural gas primarily along the Texas and Louisiana Gulf Coast, in the Permian Basin of West Texas, in both the state and federal waters of the Gulf of Mexico, and in East Texas. At December 31, 2002, our estimated net proved reserves, using constant prices which were in effect at such date, totaled 22.6 million barrels ("MMBBL") of oil, 2.0 MMBBL of natural gas liquids ("NGL"), and 81.5 billion cubic feet ("BCF") of natural gas for a total of 38.2 million barrels of oil equivalent ("MMBOE"). Approximately 64% of the estimated net proved reserves were oil or NGL, and approximately 77% of the reserves were developed.

Terms specific to the 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.

Business Strategy

In 2002, new management was put in place with the goals of refinancing and repositioning Mission's balance sheet, geographically focusing its activities, and growing its assets and cashflow through the exploration and development of oil and gas reserves. Our business strategy contains several important elements:

- Reposition the balance sheet to reduce financial leverage and increase flexibility—We completed the first step toward this goal by acquiring, in a private transaction, \$97.6 million of the 10⅞% senior subordinated notes for approximately \$71.7 million plus accrued interest. The transaction, net of fees, reduced our overall debt by \$17.6 million and provided approximately \$5.0 million for general corporate purposes. We believe that further debt reduction is necessary to bring our leverage to a more appropriate level and therefore, we are considering a number of next step alternatives in our effort to further reduce leverage. Simultaneous with the buyback, Mission amended and restated its credit facility with new lenders.
- Establish natural gas as our primary product—Our exploration and development program is specifically targeting natural gas production in several producing regions: South Texas, the Texas and Louisiana Gulf Coast, and the Permian Basin. Our goal is to move toward a 70% gas, 30% oil production mix.
- Build an in-house exploration and evaluation capability by growing our technical staff of geologists, geophysicists, and engineers who have expertise in the geographic basins we have targeted—In addition, we are utilizing an existing 3-D seismic library and continue to add to our knowledge base through reprocessing of that data as well as the acquisition and evaluation of new data. We believe that future growth in our segment of the industry is technology driven using seismic reprocessing, new seismic shoots, reservoir simulation, and sophisticated drilling and completion techniques.
- Continue development and exploitation of our existing reserves to maximize value especially in some of our more mature properties—We undertook an extensive evaluation and rationalization effort during 2002, divesting of \$69.5 million of mature properties. In addition we engaged Netherland, Sewell & Associates to perform a full evaluation of our existing reserves. We have undertaken a program to fully develop these reserves through the same technology that we are using in our exploration programs.
- Protect cash flows by hedging a percentage of our proved producing production for the current year and the two following years—The intent is to hedge a higher percentage of our production in the current year, to mitigate near term risk, with decreasing percentages in the following two years. We may be limited in the amount of hedge transactions due to credit constraints.
- Maintain control of administrative and operational functions to maximize efficiencies—In 2002, the accounting, treasury, land administration, human resources and risk management functions were brought in-house. We have continued this strategy into 2003 by terminating outsource agreements for marketing and operations of oil and gas properties. We intend to be the operator of all joint properties whenever possible.

Oil and Gas Activities

Divestitures

During 2002, we sold several properties at auction and in negotiated sales. The gross proceeds of these sales were approximately \$69.5 million, representing the sale of approximately 15.2 MMBOE of proved reserves. After costs of the sales, the remaining proceeds were used to temporarily repay bank borrowings and to pay interest on our 10⅞% senior subordinated notes.

Our gross proceeds from property sales during 2001 totaled approximately \$40.0 million. We sold several domestic oil and gas properties and our interests in Ecuadorian oil fields, representing approximately 14.3 MMBOE of proved reserves. We also sold our interests in the Snyder and Diamond M gas plants. With the sale of the Ecuadorian interests, we were relieved of approximately \$35.0 million in capital commitments related to those properties.

Merger

On May 16, 2001, Bellwether Exploration Company ("Bellwether") merged with Bargo Energy Company ("Bargo") and changed its name to Mission Resources Corporation. At that time, we increased our authorized capital stock to 60.0 million shares of common stock and 5.0 million shares of preferred stock, and amended the 1996 Stock Incentive Plan to increase the number of shares reserved for issuance under the plan by 2.0 million shares. Under the merger agreement, holders of Bargo's stock and options received a combination of cash and Mission common stock. The merger was accounted for using the purchase method of accounting. See the "Statements of Cash Flow" section of Note 2 to the consolidated financial statements for the purchase price allocation and net cash.

Mission issued $125.0 million of additional senior subordinated notes on May 29, 2001 and used most of the net proceeds of the note issuance to reduce existing borrowings under the new credit facility.

Markets and Customers

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 that we produce or that we can obtain favorable prices for the oil and gas we produce. In view of the many uncertainties affecting the supply of and demand for oil, gas and refined petroleum products, neither future oil and gas prices nor the demand for such products is predictable. Therefore, the significant affect such prices and demand will have on our company are also unpredictable. From time to time we may enter into crude oil and natural gas price collars, swaps or other similar hedge transactions to reduce our exposure to price fluctuations. A full description of our hedges and related risks can be found at Item 7A of this Form 10-K: "Quantitative and Qualitative Disclosures About Market Risk."

For several years, a significant portion of our gas production was sold to affiliates of Torch Energy Advisors, Inc ("Torch"). Our contract with Torch had an initial three-year term that began December 1996 and was renewable month to month after such term. It provided for payment of index pricing (tied to Inside FERC postings) less gathering and transportation charges to point of delivery. The contract was re-negotiated in mid-2001 to remove the index pricing provision. There were no other significant delivery commitments and our remaining oil and gas production was sold at market responsive pricing by Torch, as our agent. In early 2002, we ceased selling gas to Torch and thereafter used Torch as our agent to sell substantially all of our production to third parties at market responsive pricing. We are ending our marketing relationship with Torch on April 1, 2003 at which time our own employees will market Mission's oil and gas production.

In 2001 and 2000, sales to Torch accounted for 32% and 24%, respectively, of our oil and gas revenues. The changes in our marketing strategy discussed above have freed us from significant reliance on any one customer.

In 2002, no single customer accounted for more than 10% of our oil and gas revenues. We do not believe that the loss of any single customer or contract would materially affect Mission's business.

Regulation

Federal 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—In the event 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. 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 or other surety can be substantial, and 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. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. 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 these 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.

Competition

We compete with other oil and gas companies in all areas of our operations, including the acquisition of reserves and producing properties and the marketing of oil and gas. Many of these companies may have greater financial and other resources, which may adversely affect our ability to compete with these companies. Our ability to compete for producing properties is dependent upon the amount of funds we have available, the information available about a producing property and our ability to analyze it, and the minimum projected return on investment we are seeking.

Employees

At December 31, 2002, we were party to a Master Service Agreement ("MSA") dated October 1, 1999, and two service contracts that required Torch to operate oil and gas properties and market 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 and as a result at February 28, 2003 we had 90 employees. The MSA will effectively terminate on April 1, 2003 because all previous service contracts will have been terminated as of that date. 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 are covered by a collective bargaining agreement.

Item 2. *Properties*

Oil and Gas Properties

Our oil and gas properties are primarily located along the Texas and Louisiana Gulf Coast, in the Permian Basin of West Texas, in both state and federal waters of the Gulf of Mexico and in East Texas. The following table provides summary statistics about our properties as of December 31, 2002.

	Gulf Coast	Permian Basin	Gulf of Mexico	East Texas	Other (1)
Percent Oil/Gas	39/61	80/20	38/62	95/5	75/25
# of Economical Gross/Net Wells	253/151	1,654/266	261/49	208/186	145/51
Percent of SEC PV-10(2)	41	39	8	10	2
Average Reserve Life (years)	8	9	3	7	4
Percent Approximate Working Interest	50	20	21	85	(3)

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

(2) 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 for natural gas and oil used in our estimate were $4.74 per MMBTU and $31.17 per BBL on December 31, 2002, respectively.

(3) Approximate working interest would not be representative because the properties are so diverse.

Reserves and Production

Reserves

Our estimated net proved oil and gas reserves at December 31, 2002 were 38.2 MMBOE, representing a decrease of approximately 43% from December 31, 2001 levels. The changes in proved reserves are summarized on the table below:

	MMBOE
Proved reserves at beginning of year	67.3
Revisions of previous estimates	(8.7)
Extensions and discoveries	0.3
Production	(5.5)
Sales of reserves in-place	(15.2)
Purchase of reserves in-place	—
Proved reserves at end of year	38.2

Mission has not filed oil or gas reserve information with any foreign government or federal authority or agency that contain reserve information materially different than those presented herein.

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 and assumptions, 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 substantially. 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.

Production

The following table sets forth our production and reserve information as of and for the year ended December 31, 2002 by area.

	Net Production			Estimated Net Proved Reserves			Discounted Future Net Cash Flows(1)
Area	Oil & NGL (MBBLS)	Gas (MMCF)	Oil Equivalent (MBOE)	Oil & NGL (MBBLS)	Gas (MMCF)	Oil Equivalent (MBOE)	($000's)
Gulf Coast	740	5,365	1,634	4,818	45,584	12,415	$132,366
Gulf of Mexico	320	3,662	930	1,165	11,418	3,068	25,274
Permian Basin	1,413	2,106	1,764	12,996	19,618	16,266	128,589
East Texas	541	317	594	3,933	1,341	4,156	33,128
Other	409	1,074	588	1,698	3,529	2,286	7,545
	3,423	12,524	5,510	24,610	81,490	38,191	$326,902

(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 for natural gas and oil used in our estimate were $4.74 per MMBTU and $31.17 per BBL on December 31, 2002, respectively.

Data relating to production volumes, average sales prices, average unit production costs and oil and gas reserve information appears in Note 16 of the Notes to Consolidated Financial Statements.

Acreage

Undeveloped acreage is considered to be 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. A gross acre in the following table refers to the 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. A net acre is deemed to exist when the sum of fractional ownership of working interests in gross acres equals one. All of our developed and undeveloped acreage is domestic.

The following table sets forth information concerning our developed and undeveloped oil and gas acreage as of December 31, 2002.

	Gross	Net
Developed Acreage:		
Gulf Coast	45,676	16,517
Gulf of Mexico	177,291	35,560
Permian Basin	102,264	15,703
East Texas	2,236	1,808
Other	58,157	8,702
Total Developed Acreage	385,624	78,290
Undeveloped Acreage:		
Gulf Coast	13,389	7,444
Gulf of Mexico	52,785	17,935
Permian Basin	19,126	4,195
East Texas	—	—
Other	72,819	31,485
Total Undeveloped Acreage	158,119	61,059
Total Acreage	543,743	139,349

We believe that our title to oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to exceptions which, in our opinion, are not so material as to detract substantially from the use or value of the properties. 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.

See "Risk Factors" for a discussion of reserve estimates.

Productive Wells

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. A "net well" is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

The following table sets forth the number of productive oil and gas wells in which we own interests as of December 31, 2002.

	Gross	Net
Oil Wells:		
Gulf Coast	142	104
Gulf of Mexico	69	13
Permian Basin	943	119
East Texas	204	185
Other	117	23
Total Oil Wells	1,475	444
Gas Wells:		
Gulf Coast	111	47
Gulf of Mexico	192	36
Permian Basin	711	147
East Texas	4	1
Other	28	28
Total Gas Wells	1,046	259
Total Wells	2,521	703

Drilling Activity

Our principal drilling activities during the last three fiscal years were focused on properties along the Texas and Louisiana Gulf Coast, in the Gulf of Mexico, and in Oregon and the Permian Basin in New Mexico. Our development of the Charapa and Tiguino fields in Ecuador accounted for all international drilling activities.

The following tables set forth the results of drilling activity for the last three fiscal years:

Exploratory Wells

	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2000—Domestic	7	6	13	3.98	1.96	5.94
2000—Ecuador	—	—	—	—	—	—
2001—Domestic	2	6	8	0.92	1.13	2.05
2002—Domestic	4	1	5	1.66	.07	1.73

Development Wells

	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2000—Domestic	46	8	54	15.01	2.70	17.71
2000—Ecuador	1	3	4	0.70	2.70	3.40
2001—Domestic	48	7	55	14.24	5.13	19.37
2002—Domestic	29	3	32	10.03	1.11	11.14

Three domestic wells were in progress as of December 31, 2002.

Gas Plants

In late 2001, we sold our interests in the Snyder and Diamond M Gas Plants for gross proceeds of $11.5 million. The Point Pedernales Gas Plant, located in California, is operated by Nuevo Energy Company in conjunction with the Point Pedernales field from which the processed gas is produced. We no longer report our 19.7% interest in this plant separately, primarily because it does not process gas from third parties and therefore does not generate revenue apart from the related Point Pedernales field. The revenues and expenses of the plant are reported as NGL revenue and part of production expenses for the Point Pedernales field. The plant is included as part of our full cost pool for purposes of calculating depreciation. The Point Pedernales field, including this gas plant was sold in March 2003 to the operator. We paid them $1.8 million to assume the environmental, plugging and abandonment liabilities estimated to be between $3 million and $5 million.

Risk Factors

Risks Related to Our Business, Industry and Strategy

Our success depends upon our ability to replace reserves.

Our future performance depends upon our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Our proved reserves will generally decline as those reserves are depleted. We therefore must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

Oil and gas prices fluctuate widely, and low prices could have a material adverse impact on our business and financial results.

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 when prices decline.

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 and exploitation, 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 addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. In calculating reserves on an oil equivalent basis, gas was converted to oil equivalent at the ratio of one BBL of oil to six MCF of gas. While this ratio approximates the energy equivalency of oil to gas 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.

We face strong competition from larger oil and gas companies that may negatively affect our ability to carry on operations.

The oil and gas business is highly competitive. Many competitors have substantially larger financial resources, staffs and facilities than we do. These larger competitors include independent oil and gas producers such as Apache Corporation, Burlington Resources, Inc., Anadarko Petroleum Inc., Ocean Energy, Inc. and Devon Energy Corporation. Factors that affect our ability to compete in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the availability of alternate fuel sources and the intermediate transportation of oil and gas.

Risks Related to Financing Our Business

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Our capital expenditures were $21.4 million during 2002, $72.2 million during 2001 and $88.4 million during 2000. We have budgeted total capital expenditures in 2003 of approximately $32.0 million, however, if commodity prices continue at the current level, the capital expenditure budget will increase. Our plan is to budget capital expenditures up to discretionary cash flows. 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, bank credit facility borrowings, and the sales of oil and gas properties. We believe that our working capital and operating cash flow will be sufficient to meet planned capital expenditures in 2003. If revenues or our borrowing base decrease as a result of lower oil and gas prices, operating difficulties or declines in reserves, we may have limited ability to expend the capital necessary to undertake our 2003 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, 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 $24.0 million annually, 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 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.

Because of these issues, our new management team has undertaken a review of the various alternatives to restructure Mission and has retained the investment-banking firm of Petrie Parkman & Co. to assist in this evaluation. Among the alternatives being considered are

- a refinancing of the notes;
- a new credit facility;
- a merger with or an acquisition by another company;
- the sale of certain oil and gas properties;
- the acquisition by Mission of another company or assets;
- the addition of 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 may, from time to time, reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the counter party to the hedge, the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counter party this difference multiplied by the quantity hedged. In such case, we are required to pay the difference regardless of whether we had sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

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 Senior Vice President and Chief Financial Officer, John L. Eells, our Senior Vice President—Exploration and Geoscience, and Joseph G. Nicknish, our Senior Vice President—Operations and Engineering. 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 which occur in the marine environment, such as hurricanes or other adverse weather conditions, 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.

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.

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, and is vigorously defending these claims to avoid this liability. At this time, it is not possible to determine the amount of potential exposure that we may have for these 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/or 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/or Nuevo. The amount of bonds presently issued to Torch and Nuevo pursuant to these agreements is approximately $35.2 million. 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 Related to Our Common Stock Outstanding

Our stock price could be 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 volume and the possible delisting of our common stock could adversely affect the prevailing market for our common stock.

Historically, there has been limited trading volume for our common stock. On January 28, 2003, we received a Nasdaq Staff Determination indicating that Mission had failed to comply with Nasdaq's minimum bid price requirement of $1.00 per share for continued listing of our common stock on The Nasdaq National Market, and that, as a result, our common stock was subject to delisting from The Nasdaq National Market at the opening of business on February 6, 2003. We requested an oral hearing before a Nasdaq Listing Qualifications Panel to review the Nasdaq Staff Determination. Prior to the hearing date, proposed changes to Nasdaq's minimum bid price requirement were approved, and Mission was granted an additional 90 days, or until April 28, 2003, to come into compliance with such requirement. Because of this change, Nasdaq postponed the hearing pending a determination by Nasdaq regarding Mission's compliance with the minimum bid price requirement after April 28, 2003. In the event Mission is unable to satisfy the bid price requirement by April 28, 2003, the hearing process will re-commence. We cannot assure you that Mission will be in compliance with the amended minimum bid price requirement by April 28, 2003 or that a Nasdaq Listings Qualification Panel will grant Mission's request for continued listing of our common stock on the Nasdaq National Market System.

We are reviewing all options available to us to return to compliance with Nasdaq's continued listing requirements. The delisting of our common stock from Nasdaq may result in a reduction in some or all of the following, each of which may have a material adverse effect on our investors:

- the market price of our common stock;
- the liquidity of our common stock;
- the number of institutional investors that will be allowed by their charter to invest or consider investing in our common stock;
- the number of investors in general that will consider investing in our common stock;
- the number of market makers in our common stock;
- the availability of information concerning the trading prices and volume of our common stock;
- the number of broker-dealers willing to execute trades in shares of our common stock; and
- our ability to obtain financing for the continuation of our operations.

We do not 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 bank credit facility contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Our certificate of incorporation and bylaws 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 shareholders 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. These provisions, alone or in combination with each other and with the shareholder 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 shareholder 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).

On January 28, 2003, we received a Nasdaq Staff Determination indicating that we had failed to comply with Nasdaq's minimum bid price requirement of $1.00 per share for continued listing of our common stock on The Nasdaq National Market. As a result, our common stock was subject to delisting from The Nasdaq National Market at the opening of business on February 6, 2003. We requested an oral hearing before a Nasdaq Listing Qualifications Panel to review the Nasdaq Staff Determination.

Prior to the hearing date, proposed changes to Nasdaq's minimum bid price requirement were approved, and Mission was granted an additional 90 days, or until April 28, 2003, to come into compliance with such requirement. Because of this change, Nasdaq postponed the hearing pending a determination by Nasdaq regarding Mission's compliance with the minimum bid price requirement after April 28, 2003. In the event Mission is unable to satisfy the bid price requirement by April 28, 2003, the hearing process will re-commence. We cannot assure you that Mission will be in compliance with the amended minimum bid price requirement by April 28, 2003 or that a Nasdaq Listings Qualification Panel will grant Mission's request for continued listing of our stock on the Nasdaq National Market System.

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, 2001	$9.75	$7.56
June 30, 2001	$9.00	$6.70
September 30, 2001	$6.00	$3.80
December 31, 2001	$4.14	$2.90
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

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 1,368 stockholders of record as of March 20, 2003.

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,				
	2002	2001	2000	1999	1998
Gas revenues	$ 39,715	$ 57,705	$ 62,652	$ 41,559	$ 46,661
Oil revenues	73,164	75,530	49,601	26,705	26,991
Gas plant revenues	—	4,456	6,070	3,830	3,170
Interest and other income (loss)	(7,415)	4,386	957	1,335	1,347
Total revenues	105,464	142,077	119,280	73,429	78,169
Lease operating expense	43,222	44,773	24,553	18,702	21,748
Taxes other than income	9,246	6,656	6,273	3,072	4,012
Transportation costs	834	73	270	316	435
Gas plant expenses	—	2,118	2,677	2,366	1,967
Depreciation, depletion and amortization	43,291	45,106	32,654	23,863	39,688
Impairment expense	16,679	27,057	—	—	73,899
Disposition of hedges	—	—	8,671	—	—
Uncollectible gas revenues	—	2,189	—	—	—
Mining venture costs	—	914	—	—	—
Loss on sale of assets	2,645	11,600	—	—	—
General and administrative expenses	12,758	15,160	8,821	7,606	8,080
Interest expense	26,853	23,664	15,375	11,845	11,660
Provision for income tax (benefit)	(11,580)	(9,055)	(12,222)	(3,154)	(6,069)
Total expenses	143,948	170,255	87,072	64,616	155,420
Cumulative effect of a change in accounting method, net of deferred taxes	—	2,767	—	—	—
Net income (loss)	$ (38,484)	$ (30,945)	$ 32,208	$ 8,813	$ (77,251)
Earnings (loss) per common share	$ (1.63)	$ (1.54)	$ 2.32	$ 0.64	$ (5.50)
Earnings (loss) per common share—diluted	$ (1.63)	$ (1.54)	$ 2.27	$ 0.63	$ (5.50)
Working capital	$ 952	$ 105	$ 7,212	$ 3,770	$ 6,077
Long-term debt, net of current maturities	$226,431	$261,695	$125,450	$130,000	$104,400
Stockholders' equity	$ 65,377	$110,240	$ 56,960	$ 23,314	$ 14,489
Total assets	$342,404	$447,764	$221,545	$171,761	$131,196

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

Mission is an independent oil and gas exploration and production company. We acquire, develop and produce crude oil and natural gas. Our balanced 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 is on property enhancement through exploitation and development drilling, low to moderate risk exploration, asset redeployment and operating cost reduction and acquisitions when the opportunities are suitable. Our primary business objective is to create value through expanding reserves and production that, in turn, results in per-share increases in net asset value, cash flow and earnings.

Financing Activities

Our outstanding indebtedness totaled $225.0 million at December 31, 2002. The entire amount was attributable to the 10⅞% senior subordinated notes due in 2007. We also had $40.0 million available for borrowing under a revolving credit facility at December 31, 2002.

On May 16, 2001, Bellwether merged with Bargo and changed its name to Mission Resources Corporation. At that time, we increased our authorized capital stock to 60.0 million shares of common stock and 5.0 million shares of preferred stock, and amended the 1996 Stock Incentive Plan to increase the number of shares reserved for issuance under the plan by 2.0 million shares. Under the merger agreement, holders of Bargo's stock and options received a combination of cash and Mission common stock. We used the purchase method to account for the merger.

The merger was financed through the issuance of $80.0 million in Mission common stock to Bargo option holders and shareholders, and an initial draw down under a credit facility of $166.0 million. The funds from the credit facility were used to:

- refinance Bargo's and Bellwether's then existing credit facilities.
- pay the cash portion of the purchase price of the Bargo common stock and options, and
- fund Bargo's redemption its preferred stock immediately prior to the merger.

Mission issued $125.0 million of additional senior subordinated notes on May 29, 2001 and used most of the net proceeds of the bond issuance to reduce existing borrowings under the credit facility.

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 that is shown separately on the balance sheet. We amortize the premium 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%. Through December 31, 2002, we had amortized approximately $445,000 of the premium. Interest on the notes is payable semi-annually on April 1st and October 1st. We believe that we have sufficient liquidity provided by cash flows from operations, to pay the interest due on the notes.

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 redemption price decreases annually to 100% on April 1, 2005. Should control of Mission change, as defined in the note indenture, the note-holders could require us to purchase from them 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.

We were in compliance with the covenants of the notes at December 31, 2002 and are currently in compliance. The notes require us to comply with covenants of other existing debt if borrowings under that debt exceed $10.0 million. Because our credit facility had no balance at December 31, 2002 and we do not expect to exceed $10.0 million of borrowing under this facility in the first quarter of 2003, any potential for non-compliance with its covenants will not impact our compliance with the covenants of our notes.

Standard and Poor's and Moody's publish debt ratings for Mission. Their ratings consider a number of items including, but not limited to, our debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges and commodity price levels. At December 31, 2002, our Standard & Poor's corporate bond rating was "B" and our Moody's rating was "Caa1, Negative Outlook". A decline in our ratings would not create a default or other unfavorable change in the notes and credit facility.

Credit Facility

Mission is party to a $150.0 million credit facility with a syndicate of lenders. The Credit Facility is a revolving facility, expiring May 16, 2004, which allows Mission to borrow, repay and re-borrow under the facility from time to time. The total amount that we may borrow is called our borrowing base. The lenders periodically set the borrowing base based upon their consideration of our oil and gas reserves or other factors they deem relevant. At December 31, 2002, our borrowing base was $40.0 million. The credit facility was recently amended on October 7, 2002, reducing the maximum amount available under the credit facility from $200.0 million to $150.0 million. This modification does not limit the rights of the parties to initiate interim borrowing base redeterminations in accordance with the credit facility. As a result of the reduction in our borrowing capacity, $412,000 of previously capitalized deferred financing costs was charged to interest expense.

We paid interest on the credit facility borrowings during 2002 at an average interest rate of 3.9%. For future borrowings, we may elect to apply an annual interest rate on credit facility borrowings equal to either:

- the Eurodollar rate, plus an applicable margin ranging from 1.5% to 2.5%; or
- the greater of (i) the prime rate, as determined by Chase Manhattan Bank, or (ii) the federal funds rate plus 0.5%, plus a maximum of 1.0%.

The applicable margin for interest is based on our outstanding borrowings as a percentage of the borrowing base, and our long-term debt rating as published by Standard & Poor's or Moody's.

We also pay commitment fees on funds available under the borrowing base and fees on outstanding letters of credit. Commitment fees range from 0% to 0.5% on the unused portion of the credit facility. Letter of credit fees range from 0% to 2.5% of the unused portion of the $20.0 million letter of credit sub-facility. Commitment fees and letter of credit fees under the credit facility are based on our utilization rate and long-term debt rating.

The credit facility contains negative covenants that limit our ability, among other things, to:

- incur additional debt;
- pay dividends on stock, redeem stock or redeem subordinated debt;
- make investments;
- create liens in favor of senior subordinated debt and subordinated debt;
- sell assets;
- sell capital stock of subsidiaries;
- guarantee other indebtedness;
- enter into agreements that restrict dividends from subsidiaries;
- merge or consolidate; and
- enter into transaction with affiliates.

In addition, the credit facility requires that we maintain certain financial covenants:

- a minimum interest coverage ratio of earnings before interest, depreciation, depletion, amortization, income tax, and extraordinary items, or EBITDAX, to interest expense:

Fiscal Quarter	Interest Coverage Ratio
09/30/02 through 03/31/03	1.75 to 1.00
04/01/03 through 06/30/03	1.90 to 1.00
07/01/03 through 09/30/03	2.10 to 1.00
10/01/03 through 12/31/03	2.30 to 1.00
01/01/04 and thereafter	2.50 to 1.00

- an asset coverage or current ratio (which includes availability) of at least 1.0 to 1.0;
- a maximum ratio of senior debt to EBITDAX of 2.0 to 1.0; and
- a maximum ratio of total debt to EBITDAX:

Fiscal Quarter	Total Debt to EBITDAX
09/30/02 through 12/31/02	5.50 to 1.00
01/01/03 through 03/31/03	5.00 to 1.00
04/01/03 through 06/30/03	4.75 to 1.00
07/01/03 through 09/30/03	4.50 to 1.00
10/01/03 through 12/31/03	4.00 to 1.00
01/01/04 and thereafter	3.50 to 1.00

We had no outstanding borrowings under the credit facility and were in compliance with its covenants on December 31, 2002. At current oil and gas price levels, we expect to be in compliance with all of the credit facility covenants throughout 2003. 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.

Capital Structure

We have a highly leveraged capital structure, limiting our financial flexibility. In particular, we must pay approximately $24 million of interest annually on the notes, which limits the amount of cash provided by operations that is available for exploration and development of oil and gas properties. The notes also contain various covenants that limit our ability to, among other things, incur additional indebtedness, pay dividends, purchase capital stock and sell assets. In addition, our common stock is trading at historically low levels, which limits our ability to complete offerings of equity securities.

Because of these issues, our new management team has reviewed various alternatives to restructure the company and has retained the investment-banking firm of Petrie Parkman & Co. to assist in this evaluation. Among the alternatives being considered are

- a refinancing of the notes;
- a new credit facility;
- a merger with or an acquisition by another company;
- the sale of certain oil and gas properties;
- the acquisition by the company of another company or assets;

- the addition of 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 shareholders, 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.

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 bank credit facility borrowings, the issuance of common stock, and the sale of properties. Our primary uses of capital have been the funding of exploration and development projects and property acquisitions.

Source of Capital: Operations

Cash flow provided by operating activities, which is calculated after taking into account changes in working capital, totaled $7.2 million, $40.4 million and $60.1 million for the fiscal years 2002, 2001, and 2000, 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 and/or maximum prices on a portion of our production. Our policy is to hedge a percentage of proved producing production for the current year and the two following years.

We mitigate, but do not eliminate the potential negative effect of declining prices on operating cash flow because these hedges remove the price volatility from some of our oil and natural gas production. Hedging also prevents us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

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 10 7/8% senior subordinated notes was $225.0 million at December 31, 2002 and 2001 and was $100.0 million at the end of 2000. No credit facility borrowings were outstanding at December 31, 2002. Borrowings under our credit facility were $35.0 million and $25.5 million at the end of 2001 and 2000, respectively. At December 31, 2002, $40.0 million was available for borrowing under the credit facility. 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, 2002, 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 9.5 million shares of common stock on May 16, 2001 to holders of Bargo stock and options in order to effect the merger. Simultaneously with the merger, Mission's authorized capital stock was increased to 60.0 million shares of common stock and 5 million shares of preferred 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 sale of domestic oil and gas properties were approximately $60.4 million in 2002, $15.9 million in 2001 and $46.0 million in 2000. 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 Snyder and Diamond M gas plant interests 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 $20.6 million, $44.6 million and $71.2 million, for the fiscal years 2002, 2001 and 2000, respectively. We also spent $3.9 million in the year 2001 and $10.0 million in the year 2000 on development of the Charapa and Tiguino fields in Ecuador.

Our capital budget for 2003 totals approximately $32.0 million, with $5.8 million for exploration, $20.8 million for development, and $5.4 million for seismic data, land and related items. If commodity prices continue at the current level, the capital expenditure budget will increase. Our plan is to budget capital expenditures up to discretionary cash flows. This capital budget represents the largest planned use of our available operating cash flow. We believe that working capital and operating cash flow will be sufficient to meet the exploration and development plans detailed in the budget. To a certain degree, the ultimate timing of these capital expenditures is within our control.

Use of Capital: Acquisitions

We did not make any significant acquisitions during the year 2002. The merger with Bargo, valued at $280.9 million, was the most significant acquisition of 2001. Our other domestic property acquisitions totaled $23.5 million in the year 2001 and $7.1 million in the year 2000. Additionally, we spent $249,000 in the year 2001 and $2.0 million in the year 2000 to acquire an interest in the Tiguino field in Ecuador. The field was subsequently sold in June 2001. We continuously review acquisition opportunities and would first consider whether operating cash flows were adequate to make a desired acquisition. For larger acquisitions, we would drawdown on our credit facility or would attempt to issue equity securities, however, we cannot assure you that either of these sources would be able to provide funds adequate to complete all desired acquisitions.

Contractual Obligations and Commercial Commitments

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

Contractual Cash Obligations:	Total	2003	2004	2005	2006	2007	Thereafter
Long Term Debt*	$328,993	$24,469	$24,469	$24,469	$24,469	$231,117	$—
Operating Leases	2,755	777	703	631	622	22	—
Total Contractual Obligations	$331,748	$25,246	$25,172	$25,100	$25,091	$231,139	$—

* Includes bond principal of $225.0 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*	*2003*	*2004*	*2005*	*2006*	*2007*	*Thereafter*
Line of Credit	$ —	$ —	$—	$—	$—	$—	$—
Other Commercial Commitments	4,333	3,445	399	190	157	142	—
Total Commercial Commitments	$4,333	$3,445	$399	$190	$157	$142	$—

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 and abandon reserves, using the units of production method based upon the ratio of current production to total proved reserves. Depletion is a significant component of our net income. Proportionally, it represented over 40% of our total revenues in the year 2002 and approximately 30% of total revenues in the years 2001 and 2000. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

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 reservoir engineers. These reserve estimates are inherently imprecise as they 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. Different reserve engineers may make different estimates of reserves based on the same data. 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 reservoir 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, the impairment of oil and gas properties is not reversible at a later date even if oil and gas prices increase. We recorded a ceiling impairment of $20.8 million, pre-tax, in 2001, but will not require an impairment for the year 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.

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. At December 31, 2002, they represented a $6.9 million current liability and a $359,000 long-term liability.

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 of our hedges, which could represent either gains or losses, would be reported when calculated as an adjustment of interest and other income.

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. In the past we have chosen to obtain the fair value of commodity derivatives from the counter parties to those contracts. Since the counter parties are market makers, they were able to provide us with a literal market value, or what they would be willing to settle such contracts for as of the given date. 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.

Our existing commodity hedges are perfectly effective. Should circumstances change, all or part of the hedges could become ineffective. We would be required to record an income impact at that time. For example, should we fail to produce oil and gas in amounts adequate to cover the hedges, the derivative would immediately be considered speculative and its entire change in value would be recorded as either a gain or loss in interest and other income. Thereafter, the derivative would be marked to market each quarter, substantially increasing the volatility of our earnings.

Business Combinations and Goodwill

Recent accounting pronouncements prescribe that all future acquisitions will be accounted for using the purchase method. Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Also under recent accounting pronouncements, goodwill with an indefinite useful life is no longer amortized, but instead is assessed for impairment at least annually.

Corporate acquisitions, or mergers, have contributed significantly to Mission's growth. The merger with Bargo in 2001 was the most significant. We consider similar transactions to be a viable way to continue Mission's growth. Application of the purchase method of accounting requires us to estimate the fair value of every asset and liability, both tangible and intangible, which are acquired in a merger or corporate acquisition. We make various assumptions and estimates in arriving at those fair values. For example, current assets and liabilities are assumed to be at fair value. The most significant assets to be valued are the proved oil and gas properties. This valuation requires an estimate of proved reserves and future net revenues. We hire independent reservoir engineers to provide the estimated volume of proved reserves. The difficulties and risk of inaccuracies associated with these estimated proved reserves have been described earlier in this section under 'Full Cost Method of Accounting for Oil and Gas Assets" and in the "Risk Factors" section.

Where the full cost ceiling test requires the use of end of period prices to calculate future net revenues, we are allowed to select prices that we feel are more likely to be realized when attempting to value the reserves of an acquisition candidate. We could use flat, escalating or variable future prices in the valuation. In order to make the fair value assessment as objective as possible, we typically use future price forecasts, such as the NYMEX futures, adjusted to the wellhead by known price differentials, that are posted and accessible to the public. These prices are applied to the estimated proved reserves to arrive at estimates of future net revenues. Future net revenues are then discounted at the rate we feel is appropriate, generally our required rate of return on projects or an industry standard given existing market conditions, to arrive at the estimated fair value of proved reserves.

We apply these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or possible reserves. Independent reservoir engineers may provide estimates of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by what we consider to be an appropriate risk-weighting factor for each particular instance. The probable or possible reserves are reviewed on an individual field basis to determine the appropriate risk-weighting factor for each field. The risk-weighting factor can therefore differ substantially by field, depending upon the determinations of our engineers and geologists.

Our 2001 merger with Bargo created goodwill. The annual test for goodwill impairment requires some of the same valuation steps, and therefore the same types of estimates and management judgment, as the valuation of an acquired company. Mission designated December 31st as the date for its annual test. Based upon such test for 2002, goodwill should be fully impaired. The valuation was based on the following procedures and information:

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

This calculation resulted in an equity fair value below book equity plus goodwill. This means that the entire amount of goodwill is impaired. If goodwill is created through any future merger or corporate acquisition, the annual impairment test of goodwill would be similar.

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, 2002, we have recorded a net liability of approximately $454,000 representing approximately 266,000 MCF at an average price of $1.71 per MCF, related to imbalances on properties at or nearing depletion. We value gas imbalances using the price at which the imbalance originated if stated in the gas balancing agreement or we use the current price where there is no gas balancing agreement available. Reserve reductions 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.

Asset Retirement, Impairment or Disposal

We are adopting SFAS No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003. Currently our estimate of future plugging and abandonment and dismantlement costs is charged to income by being included in the capitalized costs that we deplete 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 must estimate asset retirement costs for all of our assets as of today, inflation adjust today's 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 will be 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 differ from the estimate, the difference will be reflected as an abandonment gain or loss in the statement of operations when the abandonment occurs. We are also developing a process through which to track and monitor the obligations for each asset.

As with previously discussed estimates, the estimation of our asset retirement obligation is dependent upon many variables. We attempt to limit impact of management's subjective judgment on these variables by using the input of qualified third parties when possible. We engaged an independent engineering firm to evaluate our properties and to provide us with estimates of abandonment costs. We used the remaining estimated useful life from the year-end Netherland, Sewell & Associates, Inc. reserve report in estimating when abandonment could be expected. 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.

Results of Operations

The table below presents the major components of financial and operating performance to be discussed (amounts in thousands, except average prices and per BOE measures):

	Year Ended December 31,		
	2002	2001(1)	2000
Oil and gas revenues—US	$112,879	$131,358	$107,938
Oil revenues—Ecuador	—	1,877	4,315
Gas plant revenues	—	4,456	6,070
Interest and other income (expense)	(7,415)	4,386	957
Total revenue	105,464	142,077	119,280
Lease operating expense—US	43,222	41,702	21,738
Lease operating expense—Ecuador	—	3,071	2,815
Taxes other than income	9,246	6,656	6,273
Transportation costs	834	73	270
Gas plant expenses	—	2,118	2,677
Depreciation, depletion and amortization—US	43,291	44,602	31,909
Depreciation, depletion and amortization—Ecuador	—	504	745
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	12,758	15,160	8,821
Interest expense	26,853	23,664	15,375
Income tax benefit	(11,580)	(9,055)	(12,222)
Net income (loss) before cumulative effect of changes in accounting method	(38,484)	(28,178)	32,208
Cumulative effect of a change in accounting method, net of deferred tax	—	2,767	—
Net income (loss)	$ (38,484)	$ (30,945)	$ 32,208
Production			
Oil and condensate (MBBLS)—US	3,423	3,303	2,206
Oil and condensate (MBBLS)—Ecuador	—	95	174
Natural gas (MMCF)	12,524	17,597	20,478
Oil equivalent (MBOE)	5,510	6,331	5,793
Average sales price, including the effect of hedges			
Oil and condensate (per BBL)—US	$ 21.37	$ 22.30	$ 20.53
Oil and condensate (per BBL)—Ecuador	$ —	$ 19.76	$ 24.80
Natural gas (per MCF)	$ 3.17	$ 3.28	$ 3.06
Average sales price, excluding the effect of hedges			
Oil and condensate (per BBL)—US	$ 21.84	$ 21.81	$ 24.40
Oil and condensate (per BBL)—Ecuador	$ —	$ 19.76	$ 24.80
Natural gas (per MCF)	$ 3.07	$ 4.13	$ 3.84
Average lease operating expense per BOE—US	$ 7.84	$ 6.69	$ 3.87
Average lease operating expense per BOE—Ecuador	$ —	$ 32.33	$ 16.18
Average G&A expenses per BOE	$ 2.32	$ 2.39	$ 1.52
Average depletion rate per BOE—US	$ 7.74	$ 6.72	$ 5.46
Average depletion rate per BOE—Ecuador	$ —	$ 5.31	$ 4.28

(1) Operations of properties acquired from Bargo began May 16, 2001 and Ecuador operations ceased June 2001.

Operations of the gas plants are summarized as follows:

	Year Ended December 31,		
	2002	2001(1)	2000
Plant product sales volume (MBBLS)	—	203	257
Average product sales price per barrel	—	$18.15	$20.31

(1) The Snyder gas plant was sold in October 2001 and the Diamond M gas plant was sold in November 2001.

Year Ended 2002 Compared to Year Ended 2001

Net Income—Net loss for the year ended December 31, 2002 was $38.5 million, or $1.63 per share on a diluted basis, while net loss for the year ended December 31, 2001 was $30.9 million, or $1.54 per share on a diluted basis.

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. This represents a 15.2% decrease in revenues.

Oil Revenues—Oil revenues decreased slightly to $73.2 million for the year 2002 from $75.5 million for the year 2001. The absence of revenues from Ecuadorian oil accounts for the majority of the decrease in oil revenues. We sold our interests in the Ecuador fields in June 2001.

Gas Revenues—Gas revenues decreased 31.1% from $57.7 million in 2001 to $39.7 million in 2002. Average realized gas prices, including hedge impact, were down $0.11 from $3.28 per MCF in the year ended December 31, 2001. Gas production declined 28.8% compared to the previous year with 12,524 MMCF and 17,597 MMCF in the years 2002 and 2001, respectively. The production decline was expected and is primarily related to our sale of additional properties throughout the year, downtime offshore and along the Gulf coast during September and October 2002 when hurricanes passed through, and the consistent production decline of our offshore properties.

Hedges—The realized prices discussed above include the impact of oil and gas hedges. A decrease of $342,000 related to hedge activity was reflected in oil and gas revenues for the year 2002, while a decrease in oil and gas revenues of $13.4 million was reflected for the previous year. Ecuadorian oil production in 2001 was not hedged.

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. A $9.0 million loss from hedge ineffectiveness, as computed under the requirements of SFAS. No. 133, was recorded in this line item for the year 2002. A net gain from hedge ineffectiveness of $4.8 million was recorded in 2001. A $1.7 million gain resulting from the settlement of the royalty calculation dispute with the MMS was also recorded in 2002.

Lease Operating Expenses—Total lease operating expenses for the year 2002 were $43.2 million compared to $44.8 million in the year 2001, a decrease of $1.6 million. Ecuadorian operations, which were sold in June 2001, accounted for $3.1 million in the year 2001. On a barrel equivalency basis, domestic lease operating expenses were $7.84 per BOE in 2002 and $6.69 per BOE in 2001. Costs for the properties acquired in the 2001 merger with Bargo and the June 2001 South Louisiana acquisition were included in lease operating expenses for the full year. Many of these properties are higher fixed costs properties. Our production declines in other areas have contributed to the increased operating expenses on a BOE basis.

Taxes Other Than Income—Production taxes, ad valorem taxes and franchise taxes are included in this amount. Production taxes are calculated as a percentage of revenue in many areas; therefore, they vary with both price and production levels. Ad valorem taxes are assessed based upon property value each year. The most significant contribution to increased ad valorem taxes is the 2001 merger with Bargo and the acquisition of South Louisiana properties in 2001 because a full year's ad valorem taxes was recognized on those properties in 2002.

Transportation Costs—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, the purchaser, Torch, assumed responsibility for transportation costs on the gas it purchased from us.

Depreciation, Depletion and Amortization—Depreciation, depletion and amortization ("DD&A") of domestic properties decreased 2.9% from $44.6 million in 2001 to $43.3 million in 2002. On a per BOE basis, DD&A increased 15.2%, from $6.72 in 2001 to $7.74 in 2002, reflecting decreases in reserves as a result of property sales and revisions. Depletion of the Ecuadorian full cost pool for 2001 was $504,000. The Ecuadorian properties were sold in June 2001.

Impairment Expense—The impairment expense in 2002 of $16.7 million is the result of the impairment of goodwill. The impairment expense reported in 2001 consists of a $20.8 million full cost ceiling impairment, the write-off of a $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 due from a foreign energy company. Management determined that the receivable was uncollectible in the fourth quarter of 2001.

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

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, for a decrease of 16.4%. Severance costs were $3.7 million in 2002 compared with $2.5 million of severance and outsourcing contract termination fees in 2001. Additionally, salaries and benefits were $3.1 million lower in 2002 than in 2001, as a result of staff reductions in early 2002. The termination of outsourcing contracts reduced management fees by $1.6 million in 2002.

Income Taxes—The benefit for federal and state income taxes for the year ended December 31, 2002 was based upon a 35% effective tax rate. The $4.3 million valuation allowance on deferred taxes applicable at December 31, 2001 has been increased to $5.3 million at December 31, 2002, because we have 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 believes it is more likely than not that we will not realize its deferred tax asset related to state income taxes.

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. Approximately $5.7 million of the increase is related to the additional 5 months that the $125 million of 10⅞% senior subordinated notes were outstanding and accruing interest during 2002. The increase is partially offset by the change in the fair value of Mission's interest rate swap, reported as a reduction of interest expense in both years. The net gain from the change in fair value was $2.2 million in 2002 and $332,000 in 2001.

Year Ended 2001 Compared to Year Ended 2000

Net Income—Net loss for the year ended December 31, 2001 was $30.9 million, or $1.54 per share on a diluted basis, while net income for the year ended December 31, 2000 was $32.2 million, or $2.27 per share on a diluted basis.

Oil and Gas Revenues—Oil and gas revenues, were $133.2 million in the year ended December 31, 2001, compared to $112.3 million for the respective period in 2000. This represents a 18.6% increase.

Oil Revenues—Total oil revenues increased to $75.5 million for the year 2001 from $49.6 million for the year 2000. Domestic oil revenues benefited from a 9% increase in realized oil prices from $20.53 in 2000 to $22.30 in 2001 and a 50% increase in domestic oil production from 2.2 MMBBLS in 2000 to 3.3 MMBBLS in 2001. The improved domestic oil production was directly related to acquisitions made in 2001, particularly the Raccoon Bend, Wasson, Levelland and East Texas fields acquired in the Bargo merger.

A decrease in Ecuadorian oil revenues of 57% occurred because the fields were sold at mid-year and realized oil prices declined. Ecuadorian oil production was 95,000 barrels, sold at $19.76, for the year 2001 compared to 174,000 barrels, sold at $24.80 for the year 2000.

Gas Revenues—Gas revenues decreased 9% from $62.7 million in 2000 to $57.7 million in 2001. Average realized gas prices, including hedge impact, increased 7% from $3.06 per MCF in the year ended December 31, 2000 to $3.28 per MCF in the year ended December 31, 2001. Gas production declined 14% compared to the previous year with 17,597 MMCF and 20,478 MMCF in the years 2001 and 2000, respectively. This decline reflected the effects of the sale of short-life gas properties in 2000.

Hedges—The realized prices discussed above include the impact of oil and gas hedges. A decrease of $13.4 million related to hedge activity was reflected in oil and gas revenues for the year 2001, while a decrease in oil and gas revenues of $24.5 million was reflected for the previous year. Ecuadorian oil production was not hedged.

Gas Plant Revenues—Gas plant revenues were $4.5 million in 2001 compared to $6.1 million in 2000. Contributing to this decrease was an 11% decline in average realized plant liquid prices. Also, only 10 months of Snyder gas plant operations and 11 months of Diamond M gas plant operations were reported in 2001 because the plants were sold during the year.

Interest and Other Income—Interest and other income increased from $957,000 reported for the year 2000 to $4.4 million reported for the year 2001. The primary reason for this increase is the inclusion of non-cash hedge ineffectiveness, as computed under the requirements of SFAS. No. 133, in this line item. A net gain from hedge ineffectiveness of $4.8 million was recorded in 2001. Two legal settlements totaling $290,000 and the write-off of $0.9 million of various receivables in 2001 partially offset the favorable impact of hedge ineffectiveness in 2001. There were no legal settlements in 2000 and $135,000 of receivables were written off in 2000.

Lease Operating Expenses—Total lease operating expenses for the year 2001 were $44.8 million compared to $24.6 million in the year 2000. On a barrel equivalency basis, domestic lease operating expenses were $6.69 per BOE in 2001 and $3.87 per BOE in 2000, increasing 92.2% from $21.7 million in 2000 to $41.7 million in 2001. As a result of the Bargo merger and the south Louisiana property acquisition, there are more wells to operate and many are oil wells that tend to be higher cost. Additionally, third-party oilfield service costs rose in response to record commodity prices at the beginning of 2001. After the Bargo merger, we reviewed our properties for cost saving opportunities. Some of these opportunities required initial spending in the form of workovers or acceleration of maintenance and repair projects in order for future operations to benefit. Ecuadorian operations, which were sold in June 2001, accounted for $2.8 million of total lease operating expenses in the year 2000 and $3.1 million in the year 2001.

Taxes Other Than Income—Production taxes, ad valorem taxes and franchise taxes are included in this amount. Production taxes are calculated as a percentage of revenue in many areas; therefore, they vary with both price and production levels. While production taxes increased on an absolute basis, they remained essentially the same on a per BOE basis in both years. Ad valorem taxes are assessed based upon property value each year. The most significant contribution to increased taxes is the acquisition of properties; however only one-half year of additional ad valorem taxes was included in 2001 for the acquired properties because they were acquired at mid-year.

Gas Plant Expenses—Gas plant expenses decreased 22% from $2.7 million in 2000 to $2.1 million in the year 2001. The decrease was related to the reduction in gas purchase costs. Also, only 10 months of Snyder gas plant operations and 11 months of Diamond M gas plant operations were reported in 2001 because the plants were sold within the year.

Transportation Costs—Transportation costs represent those expenses incurred to bring production to sale points such as pipeline fees and gas gathering fees. The increase in 2001 was primarily attributable to the properties acquired in the Bargo merger, including Raccoon Bend.

Depreciation, Depletion and Amortization—DD&A of domestic properties increased 40% from $31.9 million in 2000 to $44.6 million in 2001. On a per BOE basis, DD&A increased 23%, from $5.46 in 2000 to $6.72 in 2001, reflecting increased future development costs associated with new reserves. Depletion of the Ecuadorian full cost pool for 2000 was $745,000 compared to $504,000 in 2001. The Ecuadorian properties were sold in June 2001.

Impairment Expense—The impairment expense reported in 2001 consists of a $20.8 million full cost ceiling impairment, the write off a $6.2 million long-term receivable, and a $914,000 charge for exploratory stage mining activities. The full cost ceiling impairment is discussed in detail under "Critical Accounting Policies: Full Cost Method of Accounting for Oil and Gas Assets." The long-term receivable represented a production payment due from a foreign energy company. Management determined that the receivable was uncollectible in the fourth quarter of 2001.

Uncollectible Gas Revenues—Mission wrote off as uncollectible a $2.2 million receivable from a subsidiary of Enron Corp. as a result of the bankruptcy filing of Enron.

Loss on Sale of Assets—The loss on sale of assets consists of a $12.7 million loss on the sale of our Ecuadorian interests, which was offset by a $1.1 million gain on the sale of the Snyder and Diamond M gas plants.

General and Administrative Expenses—General and administrative expenses totaled $15.1 million in the year ended December 31, 2001 as compared to $8.8 million in the year ended December 31, 2000, for an increase of 72%. Salaries and benefits increased $2.8 million in 2001 over 2000 levels as a result of our increased employee count after the Bargo merger. Also the costs of steps to reduce future costs, including one-time charge of $1.9 million related to staff reductions and $620,000 related to the termination of outsourcing contracts, contributed to the increase.

Income Taxes—At December 31, 2000, we determined that it was more likely than not that the deferred tax assets would be realized based on current projections of taxable income due to higher commodity prices at year end 2000, and the valuation allowance was decreased by $19.8 million to zero. At December 31, 2001, however, we determined that a portion of the deferred tax assets 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 projections for future state taxable income, management believes it is more likely than not that we will not realize the deferred tax asset related to state income taxes. Based upon the projections of future taxable income, management believes it is more likely than not that we will not realize our deferred tax asset related to the impairment of the production payment, as the reversal of the deferred tax asset will result in a capital loss for federal income tax purposes, and we do not project any transactions resulting in capital gains to offset the capital loss. Therefore, the valuation allowance was increased by $4.3 million for the year ending December 31, 2001.

Interest Expense—Interest expense increased 54% to $23.7 million for the year ended December 31, 2001 from $15.4 million in the year ended December 31, 2000. Increased borrowings under the credit facility in 2001 due to the Bargo merger and the additional $125.0 million of senior subordinated notes issued in May 2001 contributed to the expense increase. Additionally, a net gain from the change in fair value of Mission's interest rate swap was reported as a reduction of 2001 interest expense.

Cumulative Effect of Change in Accounting Method—The adoption of SFAS No. 133 at January 1, 2001 resulted in the recognition of a non-cash $2.8 million loss, net of taxes, representing the cumulative effect of a change in accounting method related to an interest rate swap that did not qualify for hedge accounting treatment.

Other Matters

Dividends

At present, there is no plan to pay dividends on the 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

In July 2001, FASB issued Statement No. 143. SFAS No. 143, Accounting for Asset Retirement Obligations, provided accounting requirements for retirement obligations associated with tangible long-lived assets, including:

- the timing of liability recognition;
- initial measurement of the liability;
- allocation of asset retirement cost to expense;
- subsequent measurement of the liability; and
- financial statement disclosures.

Statement No. 143 requires that we record a liability for the fair value of our 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 obligation is added to the carrying amount of the oil and gas properties and this additional carrying amount is depreciated over the life of the properties. If the obligation is settled for other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

We are required and plan to adopt the provisions of Statement No. 143 for the quarter ending March 31, 2003. Our calculations are nearing completion. We expect to record an asset retirement liability of between $40.0 million and $50.0 million and a loss from a change in accounting method of between $1.0 and $5.0 million in the quarter ended March 31, 2003.

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 transaction. 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 Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 does not currently effect our financial statements, however, its provisions could impact the treatment of future transactions.

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 will apply SFAS No. 146 as appropriate to future activities.

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 are 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.

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".

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. We do not own an interest in any variable interest entities; therefore, this interpretation is not expected to have a material effect on our financial statements.

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. Recent oil hedges placed in periods of high oil prices were swaps that fix the price to be received.

Our realized price for natural gas per MCF is generally $0.11 less than the NYMEX MMBTU price. Our realized price for oil is generally $0.95 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.

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, 2002 prices, our cash flows would decrease by $12.7 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 10, 2003.

Oil Hedges	BBLS Per Day	Total BBLS	Type	NYMEX Price Floor/Swap Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2003	4,000	360,000	Swap	$24.82	n/a
Second Qtr. 2003	4,000	364,000	Swap	$24.31	n/a
Third Qtr. 2003	3,500	322,000	Swap	$23.95	n/a
Fourth Qtr. 2003	3,500	322,000	Swap	$23.59	n/a

Gas Hedges	MMBTU Per Day	Total MMBTU	Type	NYMEX Price Floor Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2003	15,000	1,370,000	Collar	$3.24	$4.64
Second Qtr. 2003	15,000	1,365,000	Collar	$3.18	$4.02
Third Qtr. 2003	15,000	1,380,000	Collar	$3.19	$4.10
Fourth Qtr. 2003	15,000	1,380,000	Collar	$3.24	$4.54
First Qtr. 2004	8,000	728,000	Collar	$4.13	$5.39
Second Qtr. 2004	5,000	455,000	Collar	$3.70	$4.08
Third Qtr. 2004	5,000	460,000	Collar	$3.70	$4.04
Fourth Qtr. 2004	5,000	460,000	Collar	$3.85	$4.23

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

We may also enter into financial instruments such as interest rate swaps to manage the impact of interest rates. Effective September 22, 1998, we 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. This agreement did not qualify for hedge accounting. It was marked to market each quarter. At December 31, 2002, the fair value was reported as a $1.8 million liability on the balance sheet. In February 2003, we cancelled this swap by paying the counter party approximately $1.3 million, the fair value of the swap on the cancellation date. The low market value compared favorably to our $4.8 million maximum possible exposure under the terms of the swap effective at the cancellation date. In addition, we believe that our earnings volatility will be reduced as a result of the cancellation.

Item 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders of
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, 2002 and 2001 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, 2002. 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, 2002 and 2001 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002 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, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and other Intangible Assets." As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

Houston, Texas
March 14, 2003

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2002	December 31, 2001
	(Amounts in thousands)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 11,347	$ 603
Accounts receivable and accrued revenues	18,931	25,668
Current portion of interest rate swap	—	180
Commodity derivative asset	—	8,359
Prepaid expenses and other	2,148	3,879
Total current assets	32,426	38,689
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties (full cost)		
United States—Unproved properties of $8,369 and $15,530 excluded from amortization as of December 31, 2002 and 2001, respectively	775,344	753,905
Accumulated depreciation, depletion and amortization	(474,625)	(374,167)
Net property, plant and equipment	300,719	379,738
Leasehold, furniture and equipment	3,545	3,347
Accumulated depreciation	(1,449)	(916)
Net leasehold, furniture and equipment	2,096	2,431
LONG TERM RECEIVABLE	—	899
GOODWILL & OTHER INTANGIBLES	—	15,436
OTHER ASSETS	7,163	10,571
	$ 342,404	$ 447,764

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

LIABILITIES AND STOCKHOLDERS' EQUITY	December 31, 2002	December 31, 2001
	(Amounts in thousands, except share information)	
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 24,498	$ 38,584
Commodity derivative liabilities	6,973	—
Current portion of interest rate swap	3	—
Total current liabilities	31,474	38,584
LONG-TERM DEBT		
Revolving credit facility	—	35,000
Subordinated notes due 2007	225,000	225,000
Unamortized premium on issuance of $125 million subordinated notes	1,431	1,695
Total long-term debt	226,431	261,695
COMMODITY DERIVATIVE LIABILITIES, excluding current portion	359	—
INTEREST RATE SWAP, excluding current portion	1,817	4,248
DEFERRED INCOME TAXES	16,946	31,177
OTHER LIABILITIES	—	1,820
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 5,000,000 shares authorized; none issued or outstanding at December 31, 2002 and 2001	—	—
Common stock, $0.01 par value, 60,000,000 shares authorized, 23,896,959 and 14,259,626 shares issued at December 31, 2002 and December 31, 2001, respectively	239	239
Additional paid-in capital	163,837	163,735
Retained deficit	(92,599)	(54,115)
Treasury stock, at cost, 311,000 shares	(1,905)	(1,905)
Other comprehensive income, net of taxes	(4,195)	2,286
Total stockholders' equity	65,377	110,240
	$342,404	$447,764

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
	(Amounts in thousands, except per share data)		
REVENUES:			
Gas revenues	$ 39,715	$ 57,705	$62,652
Oil revenues—United States	73,164	73,653	45,286
Oil revenues—Ecuador	—	1,877	4,315
Gas plant revenues	—	4,456	6,070
Interest and other income (expense)	(7,415)	4,386	957
	105,464	142,077	119,280
COSTS AND EXPENSES:			
Lease operating expenses—United States	43,222	41,702	21,738
Lease operating expenses— Ecuador	—	3,071	2,815
Taxes other than income	9,246	6,656	6,273
Transportation costs	834	73	270
Gas plant expenses	—	2,118	2,677
Depreciation, depletion and amortization—United States	43,291	44,602	31,909
Depreciation, depletion and amortization—Ecuador	—	504	745
Impairment expense	16,679	27,057	—
Disposition of hedges	—	—	8,671
Uncollectible gas revenues	—	2,189	—
Mining venture	—	914	—
Loss on sale of assets	2,645	11,600	—
General and administrative expenses	12,758	15,160	8,821
Interest expense	26,853	23,664	15,375
	155,528	179,310	99,294
Income (loss) before income tax benefit and cumulative effect of a change in accounting method	(50,064)	(37,233)	19,986
Income tax benefit	(11,580)	(9,055)	(12,222)
Income (loss) before cumulative effect of a change in accounting method	(38,484)	(28,178)	32,208
Cumulative effect of a change in accounting method, net of tax of $1,633	—	2,767	—
Net income (loss)	$ (38,484)	$ (30,945)	$32,208
Income (loss) per share before cumulative effect of a change in accounting method	$ (1.63)	$ (1.41)	$ 2.32
Income (loss) per share before cumulative effect of a change in accounting method—diluted	$ (1.63)	$ (1.41)	$ 2.27
Net income (loss) per share	$ (1.63)	$ (1.54)	$ 2.32
Net income (loss) per share—diluted	$ (1.63)	$ (1.54)	$ 2.27
Weighted average common shares outstanding	23,586	20,051	13,899
Weighted average common shares outstanding—diluted	23,586	20,241	14,175

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE LOSS
(Amounts in thousands)

	Common Stock		Preferred Stock		Additional Paid-In	Other Comprehensive	Retained	Treasury Stock		
	Shares	Amount	Shares	Amount	Capital	Income	Deficit	Shares	Amount	Total
Balance December 31, 1999	14,169	$142	—	$—	$ 80,455	—	$(55,378)	(311)	$(1,905)	$23,314
Stock options exercised and related tax effects	91	1	—	—	588	—	—	—	—	589
Compensation expense—stock options	—	—	—	—	849	—	—	—	—	849
Net income	—	—	—	—	—	—	32,208	—	—	32,208
Balance 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)
Balance 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)
Balance December 31, 2002	23,897	$239	—	$—	$163,837	$(4,195)	$(92,599)	(311)	$(1,905)	$65,377

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
		(Amounts in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(38,484)	$ (30,945)	$ 32,208
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	43,291	45,106	32,654
Gain on interest rate swap	(2,248)	(332)	—
Loss (gain) due to hedge ineffectiveness	9,050	(4,767)	—
Mining venture	—	729	—
Cumulative effect of a change in accounting method, net of deferred tax	—	2,767	—
Amortization of stock options	102	799	849
Amortization of deferred financing costs and bond premium	2,794	1,877	559
Loss on sale of assets	—	11,600	—
Disposition of hedges	—	—	8,671
Impairment expense	16,679	27,057	—
Other	553	455	—
Deferred taxes	(10,846)	(9,650)	(12,307)
Changes in assets and liabilities, net of acquisition:			
Accounts receivable and accrued revenues	4,364	5,669	(13,370)
Prepaid expenses and other	2,473	(3,025)	373
Accounts payable and accrued liabilities	(17,913)	(5,611)	12,217
Due to affiliates	—	—	—
Abandonment costs	(2,593)	(1,371)	(1,531)
Other	—	—	(215)
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	7,222	40,358	60,108
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and gas properties	(850)	(24,159)	(7,078)
Acquisitions of Bargo oil and gas properties	—	(142,028)	—
Proceeds on sale of oil and gas properties, net	60,396	15,868	45,906
Proceeds on sale of assets, net	—	15,668	—
Additions to oil and gas properties	(20,589)	(48,040)	(81,294)
Additions to gas plant facilities	—	(1,047)	(677)
Additions to leasehold, furniture and equipment	(198)	(527)	(2,462)
Note receivable	—	—	(1,281)
Other	—	—	(446)
NET CASH FLOWS PROVIDED BY (USED IN) INVESTING ACTIVITIES	38,759	(184,265)	(47,332)

See Notes to Consolidated Financial Statements.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
	(Amounts in thousands)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	21,000	208,754	31,400
Net proceeds from issuance of common stock	—	899	496
Payments of long-term debt	(56,000)	(199,204)	(35,950)
Proceeds from issuance of senior subordinated notes due 2007, including premium	—	126,875	—
Credit facility costs	(237)	(7,278)	(359)
NET CASH FLOWS (USED IN) PROVIDED BY FINANCING ACTIVITIES	(35,237)	130,046	(4,413)
Net increase (decrease) in cash and cash equivalents	10,744	(13,861)	8,363
Cash and cash equivalents at beginning of period	603	14,464	6,101
Cash and cash equivalents at end of period	$ 11,347	$ 603	$ 14,464

See Notes to Consolidated Financial Statements.

1. Organization

Mission Resources Corporation (the "Company") is an independent oil and gas exploration and production company. We develop and produce crude oil and natural gas. Mission's balanced portfolio comprises 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 is on property enhancement through exploitation and 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. A 10.11% ownership in the East Texas Salt Water Disposal Company is accounted for using the cost method and the $861,000 investment is included in the other assets line of the balance sheet.

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 2000. 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 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 on the 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 $1.3 million, $3.2 million and $3.3 million in the years ended December 31, 2002, 2001 and 2000, respectively. Until June 2001, the Company had two full cost pools: United States and Ecuador. The Company's interests in Ecuador were sold 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 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 on the Statement of Operations for the year ended December 31, 2001.

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. 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 equivalent barrel of domestic production was approximately $7.74 in 2002, $6.72 in 2001 and $5.47 in 2000.

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	Development Costs	Total at December 31, 2002
Costs Incurred During Periods Ended:				
December 31, 2002	$1,265	$—	$302	$1,567
December 31, 2001	5,246	—	—	5,246
December 31, 2000	328	—	—	328
December 31, 1999	502	—	—	502
Prior	726	—	—	726
	$8,067	$—	$302	$8,369

Such 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, 2002. This category of costs will transfer into the full cost pool in 2003.

Included in leasehold costs are land and seismic costs incurred in the current and prior years by the Company that are still in the evaluation stage. Approximately $2.2 million, $1.8 million and $2.8 million were evaluated and moved to the full cost pool in 2002, 2001 and 2000, respectively.

Sales of Properties—Dispositions of oil and gas properties held in the domestic full cost pool are recorded as adjustments to 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 $60.4 million, $15.9 million and $46.0 million were recorded in such manner during the years 2002, 2001, and 2000, 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 ended the year 2002 at $31.17 per barrel of oil (NYMEX WTI Cushing) and $4.74 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 elected to adjust 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 prices and the price floors 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 $11.8 million because prices prevailing at December 31, 2002 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, 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 reserves. No such impairment to capitalized costs was required for the year 2000.

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, which was recorded as part of sale of assets on the Statement of Operations for the year ended December 31, 2001.

Revenue Recognition and Gas Imbalances

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. Revenues are recognized and accrued as production occurs. In 2001 and 2000, the only customer accounting for greater than 10% of oil and gas revenues was an affiliate of Torch Energy Advisors ("Torch"). The sales amounts were $43.3 million and $26.9 million, respectively, and were part of domestic revenues. In 2002, no one customer accounts for greater than 10% of oil and gas revenues.

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. Typically no provision is made on the balance sheet to account for potential amounts due to or from Mission related to gas imbalances. Exclusive of a liability recorded for properties at or nearing depletion (see discussion below), the Company's unrecorded imbalance, valued at current prices would be a $1.4 million receivable.

When 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, 2002, the Company recorded a net liability of approximately $454,000 representing approximately 266,000 MCF at an average price of $1.71 per MCF, related to imbalances on properties at or nearing depletion. Those 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.

Receivables

The Company uses the specific write off method of accounting for receivables other than accruals. 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 $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 Statement of Operations, of $185,000, $430,000 and $135,000 related to such receivables for the years ended December 31, 2002, 2001 and 2000, respectively. The Company does not have any off-balance sheet credit exposure related to its customers.

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 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.

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 generations of future taxable income in periods when the temporary differences become deductible. 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, 2002, 2001 and 2000, was $26.4 million, $19.0 million and $13.8 million, respectively. Income taxes paid in cash, net of cash refunds, for the years ended December 31, 2001 and 2000 were $2.5 million and $109,000, respectively. A net cash refund of approximately $1.8 million was received in the year ended December 31, 2002.

A significant portion of the funding of the 2001 Bargo merger was non-cash:

Supplemental schedule of non-cash investing and financing activities:

	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, 2002, 2001 and 2000 were $96,000, $405,000 and $312,000, respectively.

Deferred Compensation Plan

In late 1997, the Company adopted the Mission Deferred Compensation Plan. This plan allows selected employees the option to defer a portion of their compensation until their retirement or termination. Such deferred compensation is invested in any one or more of six mutual funds managed by American Funds Service Company ("Fund Manager") at the direction of the employees. The Company designated Southwest Guaranty Trust Company as Trustee to supervise the Fund Manager. The market value of these investments is included in current assets at December 31, 2002, 2001 and 2000 and was approximately $419,000, $124,000 and $25,000, respectively. An equivalent liability due to the plan participants is included in current liabilities.

Stock-Based Employee Compensation Plans

At December 31, 2002, the Company has 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 or 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.

	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
Net income (loss)			
As reported	$(38,484)	$(30,945)	$32,208
Pro forma	$(39,315)	$(35,007)	$24,955
Earnings (loss) per share			
As reported	$ (1.63)	$ (1.54)	$ 2.32
Pro forma	$ (1.67)	$ (1.75)	$ 1.80
Diluted earnings (loss) per share share			
As reported	$ (1.63)	$ (1.54)	$ 2.27
Pro forma	$ (1.67)	$ (1.75)	$ 1.76

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 the $729,000 accumulated on the Balance Sheet in Other Assets as of December 31, 2000, were charged to earnings in 2001. Under existing agreements Mission is not required to pay any additional mining venture costs and there were no such charges in 2002.

Goodwill

The Financial Accounting Standards Board ("FASB") approved Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets* 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:

- compute a cash flow model of the Company's oil and gas assets using third party information and verification;
- apply risking parameters to the various categories of oil and gas reserves using reputable third party sources for risk profile;
- apply a discount rate to such valuation that approximates Mission's cost of capital and cost of debt;
- reduce this valuation by Mission's net debt to ascertain the equity fair value; and
- compare 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 to goodwill, intangible assets that are no longer being amortized, any deferred credit related to excess over cost equity method goodwill, and 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):

	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 Company's total comprehensive income for the twelve months ended December 31, 2002 and 2001 was as follows (in thousands):

	Twelve Months Ended December 31,	
	2002	2001
Net income (loss)	$(38,484)	$(30,945)
Cumulative effect attributable to adoption of SFAS No. 133, net of tax	—	(19,328)
Hedge accounting for derivative instruments, net of tax	(6,481)	21,614
Comprehensive income (loss)	$(44,965)	$(28,659)

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 accounting change	(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)

Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. 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 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.

New Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, which provided accounting requirements for retirement obligations associated with tangible long-lived assets, including:

- the timing of liability recognition;
- initial measurement of liability;
- allocation of asset retirement cost to expense;
- subsequent measure of the liability; and
- financial statement disclosures.

Statement 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 obligation is added to the carrying amount of the oil and gas properties and this additional carrying amount is depreciated over the life of the properties. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company is required and plans to adopt the provisions of Statement No. 143 for the quarter ending March 31, 2003. To accomplish this, the Company must identify all legal obligations for asset retirement obligations, if any, and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and will require the Company to gather market information and develop cash flow models. Additionally, the Company will be required to develop processes to track and monitor these obligations. The Company expects to record an asset retirement liability of between $40.0 million and $50.0 million and a loss from a change in accounting method of between $1.0 million and $5.0 million in the quarter ended March 31, 2003.

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 transaction. 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 Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 does not currently affect Mission's financial statements, however, its provisions could impact the treatment of future transactions.

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 will apply SFAS No. 146 as appropriate to future activities.

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 are 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.

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.

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. We do not own an interest in any variable interest entities; therefore, this interpretation is not expected to have a material effect on our financial statements.

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:

On May 16, 2001, Bellwether Exploration Company merged with Bargo Energy Company 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 10.11% ownership in the East Texas Salt Water Disposal Company.

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

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 23% of the shares of Torch on a fully diluted basis.

As of December 31, 2002, the Company was party to a Master Service Agreement dated October 1, 1999, the ("MSA"), and two service contracts under which Torch administers certain activities of the Company including the operation of oil and gas properties and oil and gas marketing. Previously, the Company was party to six service contracts with Torch, but four were terminated in 2002 and 2001. A $620,000 termination fee was paid on the Corporate Services Agreement and was recognized as part of general and administrative expense in the 2001 Statement of Operations. Effective February 1, 2003, the contract covering operation of oil and gas properties was terminated. Effective April 1, 2003 the contract for marketing of Mission's oil and gas commodities will terminate. Only the termination of the contract covering operations of oil and gas properties required a fee, which was $75,000. As a result of the termination of all previous service contracts with Torch, the MSA will effectively terminate on April 1, 2003.

Fees paid to Torch for marketing services were $343,000, $417,000, and $563,000, in periods ended December 31, 2002, 2001 and 2000, respectively. Sales to Torch accounted for approximately 1%, 32% and 24% of fiscal year 2002, 2001 and 2000 oil and gas revenues, respectively. Fees paid to Torch for operating our oil and gas properties were $1.4 million, $1.5 million and $1.0 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Torch was the operator of the Snyder Gas Plant. In periods ended December 31, 2001 and 2000, the fees paid by the Company to Torch were $74,000 and $96,0000, respectively. There were no such fees in 2002 because the gas plant was sold in 2001. Torch provided services in prior periods for the evaluation of potential property acquisitions and due diligence conducted in conjunction with acquisitions closed at the Company's request. The Company was charged $685,000 and $1.3 million for these costs in periods ended December 31, 2001 and 2000, respectively.

Mission currently uses an Oracle platform through a hosting agreement, effective July 1, 2002, with Novistar, previously a subsidiary of Torch. Approximately $373,000 was paid to Novistar in 2002. On January 15, 2003 it was announced that Novistar merged with Paradigm Technologies, a Petroleum Place company, creating P2 Energy Solutions. As a result of this merger, Torch owns 38% of P2 Energy Solutions.

Milam Energy, LP ("Milam") is a 51% working interest owner with the Company in several south Louisiana properties. Torch is a majority owner of Milam, and J.P. Bryan, a member of Mission's Board of Directors until October 2002 is also a managing director and stockholder of Torch. As of December 31, 2002, Milam owed the Company approximately $570,000 in joint interest billings and cash calls related to these properties. The receivable is reflected on the accounts receivable and accrued revenues line of the consolidated Balance Sheet. A portion of the outstanding receivable is past due, however, pursuant to an agreement between the parties effective March 1, 2003. Milam made a $480,000 payment on March 12, 2003. The terms also provide for Milam to timely pay Mission its joint interest billings and cash calls through July 2003.

In 2002, as part of an effort to improve liquidity, the Company sold interests in various oil and gas fields through a series of competitive bids. In July 2002, in one of those transactions, the Company sold interests in several properties located in New Mexico to Chisos, LTD ("Chisos"). J.P. Bryan, a member of Mission's board of directors until October 2002, is the President and sole owner of Chisos. Over 25 companies requested information packages on this sale and four submitted bids on these properties. The bid from Chisos was $4.0 million, which exceeded all others by $250,000 and additionally 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.

Pursuant to a separation agreement between the Company and J. Darby Sere, a former senior executive, in August 1999, the executive entered into a non-recourse promissory note with a principal amount of $332,872. The loan bears interest at an annual rate of 7% and was due and payable on August 23, 2002. After the due date all accrued interest was written-off and future accruals ceased. The loan value was reduced to $32,000 at December 31, 2002, the market value of the 78,323 Mission Resources shares that secured the loan. The Company has not deemed the loan to be in default and anticipates that more of the balance can be collected over time, or will be realized with the appreciation in the value of the stock.

In connection with the reorganization of the Company'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 will be 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 have 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 $240,000 in 2001 and $95,000 in 2000 was allocated directly to additional paid in capital. Such benefit was not material in year 2002.

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 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. The expense was calculated as the excess of the stock price on the merger date over the exercise price of the option. 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.

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. The Company's reconciliation is as follows (amounts in thousands, except per share amounts):

	Year Ended December 31, 2002			Year Ended December 31, 2001		
	Income	Shares	Per Share	Income	Shares	Per Share
Net loss	$(38,484)			$(30,945)		
Loss per common share	$(38,484)	23,586	$(1.63)	$(30,945)	20,051	$(1.54)
Effect of dilutive securities:						
Options & warrants	—	—		—	—	
Loss per common share—diluted	$(38,484)	23,586	$(1.63)	$(30,945)	20,051	$(1.54)

	Year Ended December 31, 2000		
	Income	Shares	Per Share
Net income	$ 32,208		
Earnings per common share	$ 32,208	13,899	$ 2.32
Effect of dilutive securities:			
Options & warrants	—	276	
Earnings per common share—diluted	$ 32,208	14,175	$ 2.27

In periods of loss, diluted earnings per share were not calculated since the issuance or conversion of additional securities would have had an antidilutive effect. Options and warrants equal to 1,050,500 in 2002, 2,247,000 in 2001 and 584,500 in 2000 that could potentially dilute basic earnings per share in the future were not included in the computation of diluted earnings per share because to do so would have been antidilutive.

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 $1,905,000. These treasury shares are reported at cost as a reduction to Stockholders' Equity.

Stock Incentive Plans

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, 2002, there were 936,334 options available for grants.

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

	Number of Shares	Option Price Range	
		Low	High
Balance at December 31, 1999	1,528,000	$3.34	$12.38
Granted	917,500	$4.25	$ 8.75
Surrendered	(51,999)	$3.34	$ 7.97
Exercised	(90,835)	$3.34	$ 7.63
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	(2,974,335)	$2.24	$12.38
Exercised	—	—	—
Balance at December 31, 2002	3,215,500	$0.31	$10.31
Exercisable at December 31, 2002	1,592,169	$0.31	$10.31

In 2002, many employees voluntarily surrendered out of the money options. The company intends to issue more options in 2003.

Detail of stock options outstanding and options exercisable at December 31, 2002 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	479,000	8.8	$0.96	162,335	$1.73
1996 Plan $3.34 to $12.38	2,736,500	8.9	$2.66	1,429,834	$4.17
Total	3,215,500			1,592,169	

The estimated weighted average fair value per share of options granted during 2002, 2001 and 2000 was $0.58, $3.15, and $12.75, respectively. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions.

- For 2002, expected stock price volatility of 160%; a risk free interest rate of 3.9%; and an average expected option life of 10 years
- For 2001, expected stock price volatility of 69%; a risk free interest rate of 5.3%; and an average expected option life of 10 years
- For 2000, expected stock price volatility of 65%; a risk free interest rate of 5.1%; and an average expected option life of 10 years

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. Recently, as shown on the following tables, the Company has also entered into some commodity swaps that fix the NYMEX price to be received. Hedging activities decreased revenues by $342,000, $13.4 million and $24.5 million for the years 2002, 2001 and 2000, respectively.

The Company's realized price for natural gas per MCF is generally $0.11 less than the NYMEX MMBTU price. The Company's realized price for oil is generally $0.95 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 the Company's selling price is capped at $9.00 per BBL. The Point Pedernales field was sold in March 2003.

In May 2002, several existing oil collars were cancelled. New swaps and collars, hedging forecast 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 is being amortized from Other Comprehensive Income ("OCI") over the 19-month life of the cancelled hedges, leaving $264,000 at December 31, 2002.

In October, the Company elected to de-designate all existing hedges and 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 allowed for time value to be adjusted to income quarterly. By using the DIG G-20 approach because the Company's collars and swaps meet specific criteria, the time value component is included in OCI and earnings variability is reduced. Both the realized and unrealized gains or losses related to these de-designated hedges at October 15, 2002 will be amortized over the 5 quarters remaining. The amount remaining in OCI, or the unrealized loss, related to the de-designated hedges was approximately $4.6 million at October 15, 2002. The amount of unrealized loss is being amortized over the remaining 15 month life of the hedges, leaving approximately $3.6 million at December 31, 2002.

The following tables detail the cash flow commodity hedges that were in place at December 31, 2002.

Oil Hedges

Period	BBLS Per Day	Total BBLS	Type	NYMEX Price Floor/Swap Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2003	4,000	360,000	Swap	$24.82	n/a
Second Qtr. 2003	4,000	364,000	Swap	$24.31	n/a
Third Qtr. 2003	3,500	322,000	Swap	$23.95	n/a
Fourth Qtr. 2003	3,500	322,000	Swap	$23.59	n/a

Gas Hedges

Period	MMBTU Per Day	Total MMBTU	Type	NYMEX Price Floor Avg.	NYMEX Price Ceiling Avg.
First Qtr. 2003	15,000	1,370,000	Collar	$3.24	$4.64
Second Qtr. 2003	15,000	1,365,000	Collar	$3.18	$4.02
Third Qtr. 2003	15,000	1,380,000	Collar	$3.19	$4.10
Fourth Qtr. 2003	15,000	1,380,000	Collar	$3.24	$4.54
First Qtr. 2004	5,000	455,000	Collar	$3.90	$5.25
Second Qtr. 2004	5,000	455,000	Collar	$3.70	$4.08
Third Qtr. 2004	5,000	400,000	Collar	$3.70	$4.04
Fourth Qtr. 2004	5,000	400,000	Collar	$3.85	$4.23

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 by Mission's $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 and the commodity derivatives 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, 2002 and 2001 (in thousands).

	December 31, 2002		December 31, 2001	
	Carrying Value	Approximate Fair Value	Carrying Value	Approximate Fair Value
Assets (Liabilities):				
Long-term debt: (See Note 8)				
Bank Credit Facility	$ —	$ —	$ (35,000)	$ (35,000)
Senior Subordinated Notes, excluding $1.4 million unamortized premium on $125.0 million bonds	$(225,000)	$(135,900)	$(225,000)	$(202,500)

8. Long-Term Debt

Long-term debt is comprised of the following at December 31, 2002 and 2001 (in thousands):

	December 31, 2002	December 31, 2001
Credit facility	$ —	$ 35,000
$10\frac{7}{8}$% senior subordinated notes	225,000	225,000
Subtotal	225,000	260,000
Premium on $125.0 million senior subordinated notes	1,431	1,695
Long-term debt	$226,431	$261,695

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

2003	$ —
2004	—
2005	—
2006	—
2007	225,000
Thereafter	—
	$225,000

Credit Facility

Mission is party to a $150.0 million credit facility with a syndicate of lenders. The Credit Facility is a revolving facility, expiring May 16, 2004, which allows Mission to borrow, repay and re-borrow under the facility from time to time. The total amount which may be borrowed under the facility is 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. At December 31, 2002, Mission's borrowing base was $40.0 million. The Credit Facility was recently amended on October 7, 2002, reducing the maximum amount available under the Credit Facility from $200 million to $150 million. This modification does not limit the rights of the parties to initiate interim borrowing base redeterminations in accordance with the Credit Facility. As a result of the reduction in borrowing capacity, approximately $412,000 of previously capitalized deferred financing costs related to the $200 million Credit Facility were charged to interest expense in the fourth quarter of 2002.

Mission paid interest on the Credit Facility borrowings during 2002 at an average interest rate of 3.9%. Future borrowings under the Credit Facility bear an annual interest rate, at Mission's election, equal to either:

- the Eurodollar rate, plus an applicable margin from 1.5% to 2.5%; or
- the greater of (i) the prime rate, as determined by Chase Manhattan Bank, or (ii) the federal funds rate plus 0.5%, plus a maximum of 1.0%.

The applicable margin for interest payable on outstanding borrowings is based on the utilization rate as a percentage of the total amount of funds borrowed under the Credit Facility to the borrowing base and Mission's long term debt rating. Commitment fees and letter of credit fees under the Credit Facility are also based on Mission's utilization rate and long-term debt rating. Commitment fees range from 0% to 0.5% on the unused portion of the Credit Facility. Letter of credit fees range from 0% to 2.5% of the unused portion of the $20.0 million letter of credit sub-facility.

The Credit Facility contains negative covenants that limit Mission's ability, among other things, to:

- incur additional debt;
- pay dividends on stock, redeem stock or redeem subordinated debt;
- make investments;
- create liens in favor of senior subordinated debt and subordinated debt;
- sell assets;
- sell capital stock of subsidiaries;
- guarantee other indebtedness;
- enter into agreements that restrict dividends from subsidiaries;
- merge or consolidate; and
- enter into transaction with affiliates.

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

- a minimum interest coverage ratio of earnings before interest, depreciation, depletion, amortization, income tax, and extraordinary items, or EBITDAX, to net interest expense of at least:

Fiscal Quarter	Interest Coverage Ratio
09/30/02 through 03/31/03	1.75 to 1.00
04/01/03 through 06/30/03	1.90 to 1.00
07/01/03 through 09/30/03	2.10 to 1.00
10/01/03 through 12/31/03	2.30 to 1.00
01/01/04 and thereafter	2.50 to 1.00

- an asset coverage or current ratio (which includes availability) of at least 1.0 to 1.0;
- a maximum ratio of senior debt to EBITDAX of 2.0 to 1.0; and
- a maximum ratio of total debt to EBITDAX:

Fiscal Quarter	Total Debt to EBITDAX
09/30/02 through 12/31/02	5.50 to 1.00
01/01/03 through 03/31/03	5.00 to 1.00
04/01/03 through 06/30/03	4.75 to 1.00
07/01/03 through 09/30/03	4.50 to 1.00
10/01/03 through 12/31/03	4.00 to 1.00
01/01/04 and thereafter	3.50 to 1.00

On December 31, 2002, the Company had no outstanding borrowings and was in compliance with its covenants under the Credit 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 "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 will be redeemable, in whole or in part, at the option of the Company at any time on or after April 1, 2002 at 105.44% which decreases 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, 2002, the Company was in compliance with its covenants under the Notes. In the event the Company becomes out of compliance with its Credit Facility covenants, the Notes will not be impacted unless borrowings under the Credit Facility are in excess of $10.0 million.

9. Income Taxes

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

	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
Current			
Federal	$ (734)	$ —	$ 67
State	—	595	18
Deferred			
Federal	(10,846)	(10,488)	(13,506)
Foreign	—	(300)	300
State	—	1,138	899
Total income tax benefit	$(11,580)	$ (9,055)	$(12,222)

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2002 and 2001 is as follows:

	December 31, 2002	December 31, 2001
Net operating loss carryforwards	$ 26,597	$ 12,487
Percentage depletion carryforwards	279	279
Alternative minimum tax credit carryforwards	8	742
Tax effect of hedging activities	2,259	—
State income taxes	3,140	2,134
Impairment of interest in Carpatsky	2,186	2,186
Other	1,869	1,689
Gross deferred tax assets	36,338	19,517
Less valuation allowance	(5,326)	(4,320)
Deferred income tax assets	31,012	15,197
Property, plant and equipment	(47,958)	(45,143)
Tax effect of hedging activities	—	(1,231)
Total deferred income tax liability	(47,958)	(46,374)
Net deferred income tax asset (liability)	$(16,946)	$(31,177)

At December 31, 2000, the Company determined that it was more likely than not that the deferred tax assets would be realized based on current projections of taxable income due to higher commodity prices at year end 2000, and the valuation allowance was decreased by $19.8 million to zero. At December 31, 2001, however, the Company determined that a portion of the deferred tax assets 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 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. Based upon the projections of future taxable income, 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, because the reversal of the deferred tax asset will result in a capital loss for federal income tax purposes, and the Company does not project any transactions resulting in capital gains to offset the capital loss. The valuation allowance is therefore $5.3 million and $4.3 million for the years ending December 31, 2002 and 2001, respectively.

A tax benefit related to the cumulative effect of a change in accounting method of $1,663,000 was recorded and shown as part of the cumulative effect on the consolidated statements of operations in 2001.

A tax benefit related to the exercise of employee stock options of approximately $240,000 and $95,000 was allocated directly to additional paid-in capital in 2001 and 2000, 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, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
Statutory federal income tax rate	35.0%	35.0%	34.0%
Increase (decrease) in tax rate resulting from:			
State income taxes, net of federal benefit	2.0%	(1.3%)	3.0%
Foreign income taxes, net of federal benefit	—	0.5%	1.0%
Non-deductible travel and entertainment	(0.1%)	(0.1%)	0.1%
Non-deductible goodwill amortization/impairment	(11.7%)	(0.9%)	—
Other	(0.1%)	—	—
Change in valuation allowance	(2.0%)	(8.9%)	(99.3%)
	23.1%	24.3%	(61.2%)

The Company issued 9.5 million shares of its common stock on May 16, 2001 in its acquisition of Bargo Energy Company. Management believes that the merger with Bargo was not an ownership change as defined in section 382 of the Internal Revenue Code. Therefore, the Company last had an ownership change in 1994 with the issuance of 3.4 million shares of its common stock. A change of stock ownership in the future by a significant shareholder of the Company may cause an ownership change, which would affect the Company's ability to utilize its net operating loss ("NOL") carryforwards in the future. Section 382 of the Internal Revenue Code significantly limits the amount of NOL and investment tax credit carryforwards that are available to offset future taxable income and related tax liability when a change in ownership occurs.

At December 31, 2002, the Company had net operating loss carryforwards of approximately $75.9 million, which will expire in future years beginning in 2003 and ending in 2022 as shown below.

	($ in thousands)
2003	$ 121
2004	1,371
2005	1,242
2006	1,538
2007	401
Thereafter	71,318
Total	$75,991

10. Commitments and Contingencies

Lease Commitments

At December 31, 2002, the minimum future payments under the terms of the Company's office space operating leases are as follows:

Year Ended December 31	($ in thousands)
2003	597
2004	601
2005	601
2006	601
2007	601

Rent expense was $685,000, $551,000, and $509,000 in 2002, 2001 and 2000, 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 Statement of Operations.

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 $161,000 that it has agreed to contribute toward the proper abandonment and cleanup of the Bayou fer Blanc 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 $35.2 million. 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 was 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 agreement, 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. Selected Quarterly Financial Data (amounts in thousands, except per share data) (Unaudited):

	Quarter Ended			
	December 31, 2002	September 30, 2002	June 30, 2002	March 31, 2002
Revenues	$ 27,327	$27,571	$28,266	$ 22,300
Operating income (loss)	$(22,704)	$ (3,735)	$ (9,221)	$(14,404)
Net income (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)

	Quarter Ended			
	December 31, 2001	September 30, 2001	June 30, 2001	March 31, 2001
Revenue	$ 32,522	$40,497	$35,243	$33,815
Operating income	$(39,099)	$ 1,429	$ (9,432)	$ 9,869
Net income	$ 29,260	$ 693	$ (6,007)	$ 3,629
Earnings per common share	$ (1.24)	$ 0.03	$ (0.32)	$ 0.46
Earnings per common share—diluted	$ (1.24)	$ 0.03	$ (0.32)	$ 0.44

The loss in the quarter ended December 31, 2002 includes the impact of a $16.7 million goodwill impairment. The loss in the quarter ended June 30, 2001 reflects the loss on sale of Ecuador interests. The loss in the quarter ended December 31, 2001 includes the impact of $27.0 million in pre-tax asset impairments.

13. Pro forma

The merger with Bargo completed on May 16, 2001 significantly impacted the future operating results of Mission Resources. The merger was accounted for as a purchase, and the results of operations are included in Mission's results of operations from May 16, 2001. The pro forma results are based on assumptions and estimates and are not necessarily indicative of the Company's results of operations had the transaction occurred as of January 1, 2000, or of those in the future.

The following table presents the unaudited pro forma results of operations as if the merger had occurred on January 1, 2000 and 2001, respectively (amounts in thousands, except earnings per share):

	Year Ended December 31, 2001	Year Ended December 31, 2000
Revenues	$182,252	$226,260
Income before cumulative effective of change in accounting method	$ (26,054)	$ 40,936
Net income (loss)	$ (28,821)	$ 40,936
Net income (loss) per share	$ (1.22)	$ 1.75
Net income (loss) per share—diluted	$ (1.22)	$ 1.73

14. Guarantees

The Company's subsidiaries, Mission E&P Limited Partnership, Mission Holdings LLC, and Black Hawk Oil Company are guarantors under the indenture for the $225.0 million 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 $35.2 million. 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.

Typically, in a property sale the Company will retain liability for events or occurrences that were known prior to the effective date of the sale, but not otherwise. All other liabilities become the responsibility of the purchaser after the effective date of the sale.

15. Subsequent Events (unaudited)

In March 2003, the Company sold its interests in the Point Pedernales field to the operator of the property. This transaction divests Mission of all California properties; however, the option to participate in future drilling at Tranquillion Ridge was retained. The Company paid $1.8 million to the purchaser, who in turn assumed the Company's environmental, plugging and abandonment liabilities, estimated to be between $3 million and $5 million.

Mission Resources Corporation announced on March 28, 2003 that it had acquired, in a private transaction with affiliates of Farallon Capital Management, LLC, $97.6 million of its 10⅞% senior subordinated notes (the "Notes") for approximately $71.7 million plus accrued interest. Simultaneously with the buyback, Mission has amended and restated its credit facility with new lenders, led by Farallon Energy Lending, LLC.

The amended and restated senior secured credit facility (the "Facility") has a term approximately 21 months and has initial availability of $80.0 million. The Company has drawn the full $80.0 million. Approximately $75.0 million of the drawn funds were used to acquire $97.6 million face amount of the Notes and pay closing costs associated therewith. The remaining amount is available for general corporate purposes. The Facility provides that an additional $10.0 million could be made available at the sole discretion of the lenders and that if such additional advance were to be made, it could be used only for the purpose of acquiring additional Notes. There can be no assurances that the lenders will consent to this additional advance. The interest rate on the Facility is 12% initially and will increase to 13% in early 2004. The Facility allows the Company to put in place a revolving credit facility of up to $12.5 million with a third party subject to certain limitations.

In February 2003, the Company cancelled its interest rate swap by paying the counter party approximately $1.3 million, the then market value of the swap.

On March 26, 2003, Moody's lowered the Company's senior subordinated notes credit rating to "Caa3" from "Caa1", lowered its senior implied rating to "Caa1" from "B2" and lowered its senior secured debt rating to "B2" from "B1".

16. 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.

	Year Ended December 31,		
	2002	2001	2000
Sales to unaffiliated customers:			
Oil and gas—US	$112,879	$131,358	$107,938
Oil and gas—Ecuador	—	1,877	4,315
Gas plants	—	4,456	6,070
Total sales	112,879	137,691	118,323
Interest and other income (expense)	(7,415)	4,386	957
Total revenues	105,464	142,077	119,280
Operating profit (loss) before income taxes:			
Oil and gas—US	$ 16,768	$ 38,549	$ 40,983
Oil and gas—Ecuador	—	(1,698)	719
Gas plants	—	2,338	3,393
Gain on gas plant sale	—	1,124	—
	$ 16,768	$ 40,313	$ 45,095
Unallocated corporate expenses	20,655	10,998	9,734
Interest expense	26,853	23,664	15,375
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	$ (50,064)	$ (37,233)	$ 19,986
Identifiable assets:			
Oil and gas—US	$300,719	$379,738	$125,586
Oil and gas—Ecuador	—	—	12,243
Gas plants	—	—	11,107
	$300,719	$379,738	$148,936
Corporate assets and investments	41,685	68,026	72,609
Total	$342,404	$447,764	$221,545
Capital expenditures:			
Oil and gas—US	$ 21,439	$ 68,048	$ 76,242
Oil and gas—Ecuador	—	4,151	12,130
Gas plants	—	1,047	677
	$ 21,439	$ 73,246	$ 89,049
Depreciation, depletion amortization and impairments:			
Oil and gas—US	$ 42,656	$ 41,895	$ 30,356
Oil and gas—Ecuador	—	504	745
Gas plants	—	1,025	1,211
	$ 42,656	$ 43,424	$ 32,312

17. 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 were prepared by Ryder Scott Company for the year ended December 31, 2000. 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 year ended December 31, 2002 were prepared by Netherland Sewell & Associates, Inc. These estimates are inherently imprecise and subject to substantial revision.

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, 2002	2001	2000
United States:			
Property acquisition:			
Proved properties*	$ 850	$280,281	$ 5,065
Unproved properties	—	4,100	—
Exploration	1,337	12,489	13,139
Development:			
Proved developed properties	16,377	25,609	41,615
Proved undeveloped properties	2,876	6,462	16,423
	$21,440	$328,941	$76,242
Ecuador:			
Property acquisition:			
Proved properties	—	$ 249	$ 2,013
Unproved properties	—	—	—
Development:			
Proved developed properties	—	3,902	10,117
Proved undeveloped properties	—	—	—
	$ —	$ 4,151	$12,130
Worldwide:			
Property acquisition:			
Proved properties	$ 850	$280,530	$ 7,078
Unproved properties	—	4,100	—
Exploration	1,337	12,489	13,139
Development:			
Proved developed properties	16,377	29,511	51,732
Proved undeveloped properties	2,876	6,462	16,423
	$21,440	$333,092	$88,372

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

Capitalized costs (in thousands):

	Year Ended December 31, 2002	2001
Proved properties	$ 766,975	$ 738,375
Unproved properties	8,369	15,530
Total capitalized costs	775,344	753,905
Accumulated depreciation, depletion, amortization and impairment	(474,625)	(374,167)
Net capitalized costs	$ 300,719	$ 379,738

Results of operations for producing activities (in thousands):

	Year Ended December 31, 2002
Revenues from oil and gas producing activities	$112,879
Production costs	51,987
Transportation costs	834
Income tax	21,020
Depreciation, depletion and amortization	43,291
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (4,253)

	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

	Year Ended December 31, 2000		
	United States	Ecuador	Worldwide
Revenues from oil and gas producing activities	$107,938	$4,315	$112,253
Production expenses	27,694	2,815	30,509
Disposition of hedges	8,671	—	8,671
Transportation costs	234	36	270
Income tax	15,574	—	15,574
Depreciation, depletion and amortization	30,356	745	31,101
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 25,409	$ 719	$ 26,128

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

	Year Ended December 31, 2002		
Description	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
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.

Description	Year Ended December 31, 2000 Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
United States			
Proved reserves at beginning of year	10,827	2,069	130,079
Revisions of previous estimates	1,033	93	(21,291)
Extensions and discoveries	613	4	18,418
Production	(1,987)	(219)	(20,478)
Sales of reserves in-place	(817)	(292)	(31,999)
Purchase of reserves in-place	—	—	—
Proved reserves at end of year	9,669	1,655	74,729
Proved developed reserves—			
Beginning of year	9,990	2,032	108,491
End of year	9,073	1,508	68,757
Ecuador:(1)			
Proved reserves at beginning of year	3,884	—	—
Revisions of previous estimates	(714)	—	—
Production	(174)	—	—
Purchase of reserves in-place	4,817	—	—
Proved reserves at end of year	7,813	—	—
Proved developed reserves—			
Beginning of year	245	—	—
End of year	2,135	—	—
Worldwide:			
Proved reserves at beginning of year	14,711	2,069	130,079
Revisions of previous estimates	319	93	(21,291)
Extensions and discoveries	613	4	18,418
Production	(2,161)	(219)	(20,478)
Sales of reserves in-place	(817)	(292)	(31,999)
Purchase of reserves in-place	4,817	—	—
Proved reserves at end of year	17,482	1,655	74,729
Proved developed reserves—			
Beginning of year	10,235	2,032	108,491
End of year	11,208	1,508	68,757

(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,		
	2002	2001	2000
United States:			
Future cash flow	$1,075,050	$1,200,145	$ 950,121
Future production costs	(405,251)	(502,083)	(203,464)
Future income taxes	(125,094)	(112,364)	(183,139)
Future development costs	(74,034)	(97,644)	(36,874)
Future net cash flows	470,671	488,054	526,644
10% discount factor	(214,843)	(192,483)	(133,062)
Standardized future net cash flows	$ 255,828	$ 295,571	$ 393,582
Ecuador:			
Future cash flow	$ —	$ —	$ 174,632
Future production costs	—	—	(60,899)
Future income taxes	—	—	(37,793)
Future development costs	—	—	(27,595)
Future net cash flows	—	—	48,345
10% discount factor	—	—	(18,835)
Standardized future net cash flows	$ —	$ —	$ 29,510
Worldwide:			
Future cash flow	$1,075,050	$1,200,145	$1,124,753
Future production costs	(405,251)	(502,083)	(264,363)
Future income taxes	(125,094)	(112,364)	(220,932)
Future development costs	(74,034)	(97,644)	(64,469)
Future net cash flows	470,671	488,054	574,989
10% discount factor	(214,843)	(192,483)	(151,897)
Standardized future net cash flows	$ 255,828	$ 295,571	$ 423,092

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, 2002
Standardized measure—beginning of year	$295,571
Sales, net of production costs	(60,031)
Net change in prices and production costs	160,132
Net change in income taxes	(2,635)
Extensions, discoveries and improved recovery, net of future production and development costs	3,803
Changes in estimated future development costs	4,459
Development costs incurred during the period	15,870
Revisions of quantity estimates	(78,419)
Accretion of discount	29,557
Sales of reserves in-place	(56,875)
Changes in production rates and other	(55,604)
Standardized measure—end of year	$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

	Year Ended December 31, 2000		
	United States	Ecuador	World Wide
Standardized measure—beginning of year	$ 191,604	$ 13,284	$ 204,888
Sales, net of production costs	(80,244)	(1,500)	(81,744)
Purchases of reserves in-place	—	28,389	28,389
Net change in prices and production costs	375,242	(23,174)	352,068
Net change in income taxes	(113,444)	(14,430)	(127,874)
Extensions, discoveries and improved recovery, net of future production and development costs	56,283	—	56,283
Changes in estimated future development costs	(4,942)	(1,990)	(6,932)
Development costs incurred during the period	31,095	4,329	35,424
Revisions of quantity estimates	(46,271)	(6,787)	(53,058)
Accretion of discount	19,160	1,329	20,489
Sales of reserves in-place	(34,697)	—	(34,697)
Changes in production rates and other	(204)	30,060	29,856
Standardized measure—end of year	$ 393,582	$ 29,510	$ 423,092

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 $31.17, $19.76, and $26.80 per barrel and $4.74, $2.73, and $9.52 per MMBTU, for December 31, 2002, 2001, and 2000, 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 $ 7.7 million and $35.7 million as of December 31, 2002 and 2000.

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

None.

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, 2002. 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, 2002. Such information is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Shareholder 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, 2002. 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, 2002. Such information is incorporated herein by reference.

Item 14. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Within 90 days prior to the filing date of this Form 10-K, 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. 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

There have been no significant changes in Mission's internal controls or in other factors that could significantly affect Mission's internal controls subsequent to the evaluation referred to above, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

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.
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	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).
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	Master Services Agreement dated October 1, 1999 between the Company and Torch Operating Company, Torch Energy Marketing, Inc., Torch Energy Advisors, Inc. and Novistar, Inc. (incorporated by reference to Exhibit 11.15 to the Company's Annual Report on Form 10-K filed on March 24, 2000).
10.4	Credit Agreement dated May 16, 2001 among the Company as Borrower, The Chase Manhattan Bank as administrative agent, BNP Paribas as syndication agent, First Union National Bank and Fleet National Bank as co documentation agents (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed on March 29, 2002).

10.5 First Amendment to the Credit Agreement by and among the Company and JPMorgan Chase Bank, as Administrative Agent, BNP Paribas, as Syndication Agent, First Union National Bank and Fleet National Bank, as Co-Documentation Agent, and the Lenders Signatory thereto, dated May 29, 2001 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed August 14, 2002).

10.6 Second Amendment to the Credit Agreement by and among the Company and JPMorgan Chase Bank, as Administrative Agent, BNP Paribas, as Syndication Agent, First Union National Bank and Fleet National Bank, as Co-Documentation Agent, and the Lenders Signatory Hereto, dated March 28, 2002 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed August 14, 2002).

10.7 Third Amendment to the Credit Agreement by and among the Company and JPMorgan Chase Bank, as Administrative Agent, BNP Paribas, as Syndication Agent, Wachovia Bank National Association and Fleet National Bank, as Co-Documentation Agent, and the Lenders Signatory Hereto, dated October 7, 2002 (incorporated by reference to the Company's Current Report on Form 8-K filed on October 10, 2002).

10.8 Employment Agreement effective as of May 15, 2000 between the Company and Douglas G. Manner (incorporated by reference to Exhibit 10.20 to the Company's Quarterly Report on Form 10-Q filed August 11, 2000).

10.9 Separation Agreement between the Company and Douglas G. Manner dated effective July 31, 2002 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed August 14, 2002).

10.10 Employment Agreement dated May 2, 2001, between the Company and Jonathan M. Clarkson (incorporated by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K filed on March 31, 2003).

10.11 Separation Agreement between the Company and Jonathon M. Clarkson effective September 30, 2002 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 14, 2002).

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).

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 dated May 15, 2001, between the Company and Daniel P. Foley (incorporated by reference to Exhibit 10.16 to the Company's Annual Report on Form 10-K filed on March 31, 2003).

10.17 Separation Agreement dated November 15, 2002, between the Company and Daniel P. Foley (incorporated by reference to Exhibit 10.17 to the Company's Annual Report on Form 10-K filed on March 31, 2003).

10.18 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 (incorporated by reference to Exhibit 21.1 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
23.1	Consent of KPMG LLP (incorporated by reference to Exhibit 23.1 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
23.2	Consent of Netherland Sewell & Associates, Inc. (incorporated by reference to Exhibit 23.2 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
23.3	Consent of Ryder Scott Company (incorporated by reference to Exhibit 23.3 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
23.4	Consent of T.J. Smith & Company, Inc. (incorporated by reference to Exhibit 23.4 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
23.5*	Consent of KPMG LLP related to this Annual Report in Form 10-K/A.
23.6*	Consent of Netherland Sewell & Associates, Inc. related to this Annual Report on Form 10-K/A.
23.7*	Consent of Ryder Scott Company related to this Annual Report on Form 10-K/A.
23.8*	Consent of T.J. Smith & Company, Inc. related to this Annual Report on Form 10-K/A
99.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, of the Chief Executive Officer of the Company (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
99.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, of the Chief Financial Officer of the Company (incorporated by reference to Exhibit 99.2 to the Company's Annual Report on Form 10-K filed on March 31, 2003).
99.3*	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, of the Chief Executive Officer of the Company related to this Annual Report on Form 10-K/A.
99.4*	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of the Chief Financial Officer of the Company related to this Annual Report on Form 10-K/A.

* Filed herewith.

(b) Reports on Form 8-K

(i) The Company filed a Current Report on Form 8-K on October 9, 2002, relating to the resignation and hiring of new officers.

(ii) The Company filed a Current Report on Form 8-K on October 10, 2002, relating to the amendment of its credit facility.

(iii) The Company filed a Current Report on Form 8-K on October 22, 2002, relating to election of a board member.

(iv) The Company filed a Current Report on Form 8-K on November 14, 2002, relating to third quarter 2002 results.

(v) The Company filed a Current Report on Form 8-K on November 25, 2002, relating to the sale of non-strategic properties and the associated borrowing base reduction.

(vi) The Company filed a Current Report on Form 8-K on December 19, 2002, relating to first quarter 2003 guidance, year-end 2002 reserves estimates and updates to current hedge position.

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.
- *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.
- *MMBBL*—One million Bbls of oil or other liquid hydrocarbons.
- *MMCF*—One million cubic feet of natural gas.
- *MMBTU*—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" oil and natural gas 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.
- *Discounted 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

- *Reserve life*—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, 2002, 2001 or 2000 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 geophones 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.

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

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: April 4, 2003

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)	April 4, 2003
/s/ RICHARD W. PIACENTI Richard W. Piacenti	Senior Vice President and Chief Financial Officer (principal financial officer)	April 4, 2003
/s/ ANN KAESERMANN Ann Kaesermann	Vice President—Accounting and Investor Relations, Chief Accounting Officer (principal accounting officer)	April 4, 2003
/s/ JUDY LEY ALLEN Judy Ley Allen	Director	April 4, 2003
/s/ DAVID A.B. BROWN David A.B. Brown	Director	April 4, 2003
/s/ ROBERT R. ROONEY Robert R. Rooney	Director	April 4, 2003
/s/ HERBERT C. WILLIAMSON Herbert C. Williamson	Director	April 4, 2003

MISSION RESOURCES CORPORATION AND SUBSIDIARIES

I, Robert L. Cavnar, certify that:

1. I have reviewed this annual report on Form 10-K/A of Mission Resources Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 4, 2003

/s/ ROBERT L. CAVNAR

Robert L. Cavnar
Chairman and Chief Executive Officer

I, Richard W. Piacenti, certify that:

1. I have reviewed this annual report on Form 10-K/A of Mission Resources Corporation;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 4, 2003

/s/ RICHARD W. PIACENTI

Richard W. Piacenti
Senior Vice-President and Chief Financial Officer

Officers

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Richard W. Piacenti
Senior Vice President and Chief Financial Officer

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

Joseph G. Nicknish
Senior Vice President – Operations and Engineering

Lloyd Armstrong
Vice President – Revenue Administration

Ann Kaesermann
Vice President – Accounting and Investor Relations, CAO

Marshall L. Munsell
Vice President – Land & Land Administration

A. Kent Rogers
Vice President – Operations

Byron Yeatman
Vice President – Exploitation

Leslee M. Ranly
Corporate Secretary

Board of Directors

Judy Ley Allen
Compensation Committee Member

David A.B. Brown
Audit Committee Chairman

Robert L. Cavnar
Chairman, President and Chief Executive Officer

Robert R. Rooney
Compensation Committee Chairman
Audit Committee Member

Herbert C. Williamson III
Audit Committee Member

Shareholder Information

The ticker symbol for Mission Resources Corporation is MSSN. Daily stock reports published in newspapers carry trading summaries for the company under "Mission Res." At December 31, 2002, the company had 23,585,959 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.

Annual Meeting

Mission shareholders are cordially invited to attend the Annual Meeting of Shareholders, which will be held on Tuesday, May 20, 2003, at 10:00 a.m. CST at the Four Seasons Hotel, 1300 Lamar, Houston, Texas.

Corporate Offices

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Houston, TX 77010-3039
(713) 495-3000
www.mrcorp.com

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

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.

MISSION
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