MERIDIAN RESOURCE CORP
Form 10-K
April 15, 2003

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

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

For the fiscal year ended: DECEMBER 31, 2002 Commission file number: 1-10671

THE MERIDIAN RESOURCE CORPORATION
(Exact name of registrant as specified in its charter)

TEXAS	76-0319553
(State of incorporation)	(I.R.S. Employer Identification No.)
1401 ENCLAVE PARKWAY, SUITE 300, HOUSTON, TEXAS	77077
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 281-597-7000

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

(Title of each class)	(Name of each exchange on which registered)
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None

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

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

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

Aggregate market value of shares of common stock held by non-affiliates of the Registrant at June 30, 2002: $182,962,375

Number of shares of common stock outstanding at March 18, 2003: 50,089,118

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form (Items 10, 11, 12, 13, 14 and 15) is incorporated by reference from the registrant's Proxy Statement to be filed on or before April 30, 2003.

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PART I

ITEM 1. BUSINESS

GENERAL

The Meridian Resource Corporation ("Meridian" or the "Company") is an independent oil and natural gas company that explores for, acquires and develops oil and natural gas properties utilizing 3-D seismic technology. Our operations are focused on the onshore oil and gas regions in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico. As of December 31, 2002, we had proved reserves of approximately 167 Bcfe with a present value of future net cash flows before income taxes of approximately $460 million. Approximately 64% of our proved reserves were natural gas and approximately 76% were classified as proved developed.

We believe we are among the leaders in the use of 3-D seismic technology by independent oil and natural gas companies. We also believe we have a competitive advantage in the areas where we operate because of our large inventory of lease acreage, seismic data coverage and experienced geotechnical, land and operational staff.

The Company generates and drills exploration projects primarily in the south Louisiana and south Texas Gulf Coast region. During the course of the prior ten years, we have generated and participated in the discovery of over 800 BCFE of new reserves. Recently, we have developed several shallower, low-risk exploration projects that we believe provide the Company with a higher level of confidence for success as well as better control of risks and costs than the deep exploration plays we have traditionally developed and drilled. Examples of this strategy include the Company's Thornwell and Biloxi Marshlands fields. While this strategy has proven to be successful and will be the focus of our efforts to develop new oil and gas reserves in our producing region, it does not replace entirely the Company's continued efforts to explore for deep reserves where the probability of success and costs justify the risks associated with such opportunities.

We currently have interests in leases and options to lease acreage in approximately 299,000 gross acres in Louisiana, Texas and the Gulf of Mexico. We also have rights or access to approximately 7,500 square miles of 3-D seismic data, which we believe to be one of the largest positions held by a company of our size operating in our core areas of operation.

The Meridian Resource Corporation was incorporated in Texas in 1990, with headquarters located at 1401 Enclave Parkway, Suite 300, Houston, Texas 77077. You can locate additional information on the internet at www.tmrc.com and www.sec.gov.

EXPLORATION STRATEGY

Meridian has focused its exploration strategy on prospects where large accumulations of oil and natural gas have been found and where we believe substantial oil and natural gas reserve additions can be achieved through exploratory drilling in which we use 3-D seismic technology. We also seek to identify prospects with multiple potential productive zones to maximize the probability of success. In an effort to mitigate the risk of dry holes, we engage in a rigorous and disciplined review of each prospect utilizing the latest in technological advances with respect to prospect analysis and evaluation.

Our process of review of exploration prospects begins with a thorough analysis of the prospect using traditional methods of prospect development and computer technology to analyze all reasonably available 2-D seismic data and other geological and geophysical data with respect to the prospect. If the results of this analysis

confirm the prospect potential, we seek to acquire 3-D seismic data over leasehold interests in, or options to acquire leasehold interests in, the prospect area. We then apply state-of-the-art processing technology to assimilate and correlate the 2-D and 3-D seismic data on the prospect with all available well-log information and other data to create a computer model that we design to identify the location and size of potential hydrocarbon accumulations in the prospect. If our analysis of the model continues to confirm the potential for hydrocarbon accumulations within our prospect objectives, we will then seek to identify the most desirable drilling location to test the prospect and to maximize production if the prospect is successful.

The process of developing, reviewing and analyzing a prospect from the time we first identify it to the time that we drill it is generally a 12 to 36 month process in which we reject many potential prospects at various levels of the review. Although the cost of designing, acquiring, processing and interpreting 3-D seismic data and acquiring options and leases on prospects that we do not ultimately drill requires greater up-front costs per prospect than traditional exploration techniques, we believe that the elimination of prospects that are unlikely to be successful and that might otherwise have been drilled at a substantial cost results in significantly lower finding costs. We also believe that our use of 3-D seismic technology minimizes development costs by allowing for the better placement of the initial and, if necessary, development wells.

We attempt to match our exploration risks with expected results by retaining working interests that historically have been between 50% and 75% in the Company's onshore wells. Our working interests may vary in certain prospects depending on participation structure, assessed risk, capital availability and other factors. In addition, working interests in offshore properties we acquired in a 1997 acquisition average between 3% and 50% in each well. Our offshore properties generally involve higher drilling costs and risks commonly associated with offshore exploration, including costs of constructing exploration and production platforms and pipeline interconnections, as well as weather delays and other matters.

3-D SEISMIC TECHNOLOGY

An integral part of Meridian's exploration strategy is the disciplined application of 3-D seismic technology to every exploration and development prospect that we drill. We begin with the geological idea, develop subsurface maps based on analogous wells in the region and use 2-D seismic data, where available, to define our prospect areas. If the prospect meets our standards of risk and opportunity, we will acquire a 3-D seismic survey over the prospect area as a last method to further define the objectives, reduce the risks of drilling a dry hole and/or improve our opportunity for success. The entire process from the geological concept to the final interpretation is controlled by Meridian's management and professional staff. People are our most important ingredient in this formula. Meridian has put together a high quality professional and technical staff that has successfully explored for oil and gas in its region of focus-south Louisiana, southeast Texas and offshore Gulf of

Mexico. Meridian designs its 3-D seismic surveys in conjunction with its geological and geophysical staff, manages the field acquisition efforts with its geophysical staff, processes the 3-D data in house using Western Geophysical's Omega software system, in conjunction with the geological and geophysical technicians, and interprets the 3-D data utilizing Schlumberger's GeoQuest interpretative software, where all of the respective disciplines interact to develop the final product.

In addition, almost all of Meridian's producing properties have 3-D seismic surveys covering its fields, which we believe gives Meridian an advantage to develop and exploit the proved undeveloped and proved developed non-producing reserves from those fields.

As a result of our disciplined method of exploration we believe that we are able to develop a more accurate definition of the risk profile of exploration prospects than was previously available using traditional exploration techniques or than is used by our competition in our areas of focus. We therefore believe that our method of exploration utilizing the 3-D technology increases our chances for success rates and reduces our dry-hole costs compared to companies that do not engage in a similar process.

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OIL AND GAS PROPERTIES

The following table sets forth production and reserve information by region with respect to our proved oil and natural gas reserves as of December 31, 2002. The reserve volumes were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	LOUISIANA	GULF O MEXIC
PRODUCTION FOR THE YEAR ENDED DECEMBER 31, 2002		
Oil (MBbls)	2,067	146
Natural Gas (MMcf)	13,959	1,619
RESERVES AS OF DECEMBER 31, 2002		
Oil (MBbls)	9,150	775
Natural Gas (MMcf)	95,503	12,123
ESTIMATED FUTURE NET CASH FLOWS ($000)(1)		
PRESENT VALUE OF FUTURE NET CASH FLOWS BEFORE INCOME TAXES ($000)(1) ...		
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS ($000)(1)		

(1) Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes discounted at 10%. For calculating the Present Value of Future Net Cash Flows as of December 31, 2002, we used the prices at December 31, 2002, which were $31.82 per Bbl of oil and $4.96 per Mcf of natural gas.

PRODUCTIVE WELLS

At December 31, 2002, 2001 and 2000, we held interests in the following productive wells. The majority of the 31 gross (5.1 net) wells in the Gulf of Mexico as of December 31, 2002, have multiple completions.

	2002 GROSS	2002 NET	2001 GROSS	2001 NET	2000 GROSS	2000 NET
Oil Wells	67	42	61	41	118	96
Natural Gas Wells ...	71	28	79	34	96	46
Total	138	70	140	75	214	142

OIL AND NATURAL GAS RESERVES

Presented below are our estimated quantities of proved reserves of crude oil and natural gas, Future Net Cash Flows, Present Value of Future Net Revenues and the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2002. Information set forth in the following table is based on reserve reports prepared in accordance with the rules and regulations of the Securities and Exchange Commission (the "Commission"). The reserve volumes were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers, as of December 31, 2002.

	PROVED RESERVES AT DECEMBER 31, 20		
	DEVELOPED PRODUCING	DEVELOPED NON-PRODUCING	UNDEVEL
	(DOLLARS IN THOUSANDS)		
Net Proved Reserves:			
Oil (MBbls)	4,233	2,608	3,084
Natural Gas (MMcf)	38,043	48,205	21,378
Natural Gas Equivalent (MMcfe)	63,441	63,852	39,885
Estimated Future Net Cash Flows(1)			
Present Value of Future Net Cash Flows (before income taxes)(1)			
Standardized Measure of Discounted Future Net Cash Flows(1)			

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(1) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes discounted at 10%. For calculating the Estimated Future Net Cash Flows, the Present Value of Future Net Cash Flows and the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2002, we used the prices at December 31, 2002, which were $31.82 per Bbl of oil and $4.96 per Mcf of natural gas.

You can read additional reserve information in our Consolidated Financial Statements and the Supplemental Oil and Gas Information (unaudited) included elsewhere herein. We have not included estimates of total proved reserves, comparable to those disclosed herein, in any reports filed with federal authorities other than the Commission.

In general, our engineers based their estimates of economically recoverable oil and natural gas reserves and of the future net revenues therefrom on a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves, that are based on the mechanical status of the completion, may also define the degree of speculation involved. For these reasons, 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 the future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Therefore, the actual production, revenues, severance and excise taxes, and development and operating expenditures with respect to reserves likely will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that we may develop and produce in the future are often based on volumetric calculations and by 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, and subsequent evaluation of the same reserves, based on production history, will result in variations, which may be substantial, in the estimated reserves.

In accordance with applicable requirements of the Commission, the estimated discounted future net revenues from estimated proved reserves are based on prices and costs as of the date of the estimate unless such prices or costs are contractually determined at that date. Actual future prices and costs may be materially higher or lower. Actual future net revenues 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.

OIL AND NATURAL GAS DRILLING ACTIVITIES

The following table sets forth the gross and net number of productive and dry exploratory and development wells that we drilled and completed in 2002, 2001 and 2000.

	GROSS WELLS			NET WELLS		
	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOT
EXPLORATORY WELLS						
Year ended December 31, 2002	6	1	7	3.7	0.9	4
Year ended December 31, 2001	9	7	16	4.2	5.8	10
Year ended December 31, 2000	11	5	16	7.4	3.6	11
DEVELOPMENT WELLS						
Year ended December 31, 2002	2	1	3	1.4	0.9	2
Year ended December 31, 2001	4	2	6	2.8	1.8	4
Year ended December 31, 2000	7	--	7	4.2	--	4

Meridian had 1 gross (0.9 net) well in progress at December 31, 2002.

PRODUCTION

The following table summarizes the net volumes of oil and natural gas produced and sold, and the average prices received with respect to such sales, from all properties in which Meridian held an interest during 2002, 2001 and 2000.

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
PRODUCTION:			
Oil (MBbls)	2,213	2,918	3,987
Natural gas (MMcf)	15,578	22,085	27,672
Natural gas equivalent (MMcfe)	28,856	39,594	51,596
AVERAGE PRICES:			
Oil ($/Bbl)	$ 24.67	$ 25.17	$ 27.32
Natural gas ($/Mcf)	$ 3.36	$ 4.67	$ 4.14
Natural gas equivalent ($/Mcfe)	$ 3.71	$ 4.46	$ 4.33
PRODUCTION EXPENSES:			
Lease operating expenses ($/Mcfe)	$ 0.41	$ 0.42	$ 0.35
Severance and ad valorem taxes ($/Mcfe)	$ 0.29	$ 0.30	$ 0.30

ACREAGE

The following table sets forth the developed and undeveloped oil and natural gas leasehold acreage in which Meridian held an interest as of December 31, 2002. Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage contains proved reserves.

	DECEMBER 31, 2002			
	DEVELOPED		UNDEVELOPED	
REGION	GROSS	NET	GROSS	NET
TEXAS	425	53	4,000	1,110
LOUISIANA	31,061	15,564	23,134	20,913
GULF OF MEXICO	47,018	6,631	5,000	4,650
TOTAL	78,504	22,248	32,134	26,673

In addition to the above acreage, we currently have options or farm-ins to acquire leases on approximately 188,283 gross (166,955 net) acres of undeveloped land located in Louisiana. Our fee holdings of 5,000 acres have been included in the undeveloped acreage and have been reduced to reflect the interest that we have leased to third parties.

GEOLOGIC AND GEOPHYSICAL EXPERTISE

Meridian employs approximately 87 full-time non-union employees and 12 contract employees. This staff includes geologists, geophysicists and consultants with over 350 combined years of experience in generating onshore and offshore prospects in the Louisiana and Texas Gulf Coast region. Our geologists and geophysicists generate and review all prospects using 2-D and 3-D seismic technology and analogues to producing wells in the areas of interest. Talented geoscientists with experience in finding oil and gas in large quantities and who focus in our niche region of focus are unique and difficult to attract and retain on a long-term basis.

MARKETING OF PRODUCTION

We market our production to third parties in a manner consistent with industry practices. Typically, the oil production is sold at the wellhead at field-posted prices, less gathering and gravity adjustments, and the natural gas is sold at posted indices, less applicable gathering and dehydration charges, adjusted for the quality of natural gas and prevailing supply and demand conditions. The natural gas production is sold under short-term contracts or in the spot market.

The following table sets forth purchasers of our oil and natural gas that accounted for more than 10% of total revenues for 2002, 2001 and 2000.

	YEAR ENDED DECEMBER 31,		
CUSTOMER	2002	2001	2000
Equiva Trading Company(1)	33%	30%	36%
Louisiana Intrastate Gas	17%	20%	12%
Conoco, Inc	12%	--	--
Superior Natural Gas	--	13%	14%

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(1) This entity is an affiliate of Shell.

Other purchasers for our oil and natural gas are available; therefore, we believe that the loss of any of these purchasers would not have a material adverse effect on the results of operations.

MARKET CONDITIONS

Our revenues, profitability and future rate of growth substantially depend on prevailing prices for oil and natural gas. Oil and natural gas prices have been extremely volatile in recent years and are affected by many factors outside our control. Since 1992, prices for West Texas Intermediate crude have ranged from $8.00 to $37.20 per Bbl and the Gulf Coast spot market natural gas price at Henry Hub, Louisiana, has ranged from $1.08 to $9.98 per MMBtu. The average price we received during the year ended December 31, 2002, was $3.71 per Mcfe compared to $4.46 per Mcfe during the year ended December 31, 2001. The volatile nature of energy markets makes it difficult to estimate future prices of oil and natural gas; however, any prolonged period of depressed prices would have a material adverse effect on our results of operations and financial condition.

The marketability of our production depends in part on the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Federal and state regulation of oil and natural gas production and transportation, general economic conditions, changes in supply and changes in demand could adversely affect our ability to produce and market our oil and natural gas. If market factors were to change dramatically, the financial impact on us could be substantial. We do not control the availability of markets and the volatility of product prices are beyond our control and therefore represent significant risks.

COMPETITION

The oil and natural gas industry is highly competitive for prospects, acreage and capital. Our competitors include numerous major and independent oil and natural gas companies, individual proprietors, drilling and income programs and partnerships. Many of these competitors possess and employ financial and personnel resources substantially greater than ours and may, therefore, be able to define, evaluate, bid for and purchase more oil and natural gas properties. There is intense competition in marketing oil and natural gas production, and there is competition with other industries to supply the energy and fuel needs of consumers.

REGULATION

The availability of a ready market for any oil and natural gas production depends on numerous factors that we do not control. These factors include regulation of oil and natural gas production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of available natural gas pipeline capacity in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between multiple owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies.

Oil and natural gas production operations are subject to various types of regulation by state and federal agencies. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. In addition, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that govern the oil and natural gas industry and its individual members, some of

which carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

All of our federal offshore oil and gas leases are granted by the federal government and are administered by the U. S. Minerals Management Service (the "MMS"). These leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations and the calculation of royalty payments to the federal government. Ownership interests in these leases generally are restricted to United States citizens and domestic corporations. The MMS must approve any assignments of these leases or interests therein.

The federal authorities, as well as many state authorities, require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and gas. Individual states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of the federal authorities, as well as many state authorities, limit the rates at which we can produce oil and gas on our properties.

Federal Regulation

The FERC regulates interstate natural gas pipeline transportation rates and service conditions, both of which affect the marketing of natural gas produced by us, as well as the revenues we receive for sales of such natural gas. Since the latter part of 1985, culminating in 1992 in the Order No. 636 series of orders, the FERC has endeavored to make natural gas transportation more accessible to gas buyers and sellers on an open and non-discriminatory basis. The FERC believes "open access" policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put gas sellers into more direct contractual relations with gas buyers. As a result of the Order No. 636 program, the marketing and pricing of natural gas has been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been terminated and replaced by regulations which require pipelines to provide transportation and storage service to others who buy and sell natural gas. In addition, on February 9, 2000, FERC issued Order No. 637 and promulgated new regulations designed to refine the Order No. 636 "open access" policies and revise the rules applicable to capacity release transactions. These new rules will, among other things, permit existing holders of firm capacity to release or "sell" their capacity to others at rates in excess of FERC's regulated rate for transportation services.

It is unclear what impact, if any, these new rules or increased competition within the natural gas transportation industry will have on us and our gas sales efforts. It is not possible to predict what, if any, effect the FERC's open access or future policies will have on us. Additional proposals and/or proceedings that might affect the natural gas industry may be considered by FERC, Congress or state regulatory bodies. It is not possible to predict when or if any of these proposals may become effective or what effect, if any, they may have on our operations. We do not believe, however, that our operations will be affected any differently than other gas producers or marketers with which we compete.

Price Controls

Our sales of natural gas, crude oil, condensate and natural gas liquids are not regulated and transactions occur at market prices.

State Regulation of Oil and Natural Gas Production

States where we conduct our oil and natural gas activities regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas and resources. In addition, most states regulate the rate of production and may establish the maximum daily production allowables for wells on a market demand or conservation basis.

Environmental Regulation

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require us to acquire a permit before we commence drilling; restrict the types, quantities and concentration of various substances that we can release into the environment in connection with drilling and production activities; limit or prohibit our drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Moreover, the general trend toward stricter standards in environmental legislation and regulation is likely to continue. For instance, as discussed below, legislation has been proposed in Congress from time to time that would cause certain oil and gas exploration and production wastes to be classified as "hazardous wastes", which would make the wastes subject to much more stringent handling and disposal requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as on the operating costs of the oil and natural gas industry in general. Initiatives to further regulate the disposal of oil and gas wastes have also been considered in the past by certain states, and these various initiatives could have a similar impact on us. We believe that our current operations substantially comply with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us.

OPA. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area where an offshore facility is located. The OPA makes each responsible party liable for oil-removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the party caused the spill by gross negligence or willful misconduct or if the spill resulted from a violation of a federal safety, construction or operating regulation. The liability limits likewise do not apply if the party fails to report a spill or to cooperate fully in the cleanup. Few defenses exist to the liability imposed by the OPA.

The OPA also imposes ongoing requirements on a responsible party, including the requirement to maintain proof of financial responsibility to be able to cover at least some costs if a spill occurs. In this regard, the OPA requires the lessee or permittee of an offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million ($10 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to a crude oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150 million depending on the risk represented by the quantity or quality of crude oil that is handled by the facility. The MMS has promulgated regulations that implement the financial responsibility requirements of the OPA.

Under the MMS regulations, the amount of financial responsibility required for an offshore facility is increased above the minimum amount if the "worst case" oil spill volume calculated for the facility exceeds certain limits established in the regulations.

The OPA also imposes other requirements, such as the preparation of an oil-spill contingency plan. We have such a plan in place. Failure to comply with ongoing requirements or inadequate cooperation during a spill may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under the OPA and we believe that compliance with the OPA's financial responsibility and other operating requirements will not have a material adverse impact on us.

CERCLA. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state statutes impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances. Under CERCLA, persons or companies that are statutorily liable for a release could be subject to joint-and-several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We have not been notified by any governmental agency or third party that we are responsible under CERCLA or a comparable state statute for a release of hazardous substances.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), imposes restrictions and controls on the discharge of produced waters and other oil and gas wastes into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges for oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liability and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act ("RCRA") is the principle federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating expenses.

TITLE TO PROPERTIES

As is customary in the oil and natural gas industry, we make only a cursory review of title to undeveloped oil and natural gas leases at the time we acquire them. However, before drilling commences, we search the title, and remedy any material defects before we actually begin drilling the well. To the extent title opinions or other investigations reflect title defects, we (rather than the seller or lessor of the undeveloped property) typically are obligated to cure any such title defects at our expense. If we are unable to remedy or cure any title defects so that it would not be prudent for us to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our oil and natural gas properties,

some of which are subject to immaterial encumbrances, easements and restrictions. Under the terms of our credit facility, we may not grant liens on various properties and must grant to our lenders a mortgage on our oil and gas properties of at least 90% of our present value of proved properties. Our own oil and natural gas properties also typically are subject to royalty and other similar noncost-bearing interests customary in the industry.

We acquired substantial portions of our 3-D seismic data through licenses and other similar arrangements. Such licenses contain transfer and other restrictions customary in the industry.

ITEM 2. PROPERTIES

PRODUCING PROPERTIES

For information regarding Meridian's properties, see "Item 1. Business" above.

ITEM 3. LEGAL PROCEEDINGS

On October 29, 2002, Veritas DGC Land Inc. ("Veritas Land") filed a complaint against Meridian. The dispute concerns a contract for seismic services for Meridian's Biloxi Marsh project in St. Bernard Parish, Louisiana. Purporting to invoke force majeure, Veritas Land, together with Veritas DGC Inc. (collectively, "Veritas"), unilaterally terminated the parties' contract. The main dispute is whether Veritas had breached the parties' contract before the alleged force majeure events and/or when it terminated the contract; Meridian has not made any payments to Veritas under the parties' contract. Veritas' complaint seeks breach-of-contract damages of approximately $6.8 million together with interest, costs and attorneys' fees.

On December 23, 2002, Meridian filed an answer denying the relief sought by Veritas and asserting a counterclaim against Veritas (1) declaring that (i) Meridian is not in breach of the parties' seismic contract, (ii) Meridian owes no amounts to Veritas under the parties' seismic contract or otherwise, (iii) Veritas materially breached the parties' contract, and (iv) Veritas Land is solidarily liable to Meridian for all liability of Veritas DGC Inc., and (2) seeking an award to Meridian of all attorneys' fees, court costs and other expenses, amounts and damages incurred or suffered (or to be incurred or suffered) by Meridian. On January 27, 2003, Veritas Land filed an answer to Meridian's counterclaim, generally denying the counterclaim and asserting various affirmative defenses thereto. Veritas DGC Inc. has not yet answered the counterclaim.

No scheduling order has yet been issued. The parties have not yet issued discovery to each other. Meridian intends to vigorously defend the claims against it and to vigorously prosecute its counterclaim.

There are no other material legal proceedings to which Meridian or any of its subsidiaries or partnerships is a party or to which any of its property is subject, other than ordinary and routine litigation incidental to the business of producing and exploring for crude oil and natural gas.

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

No matters were submitted to a vote of Meridian's security holders during the fourth quarter of 2002.

PART II

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

PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our Common Stock is traded on the New York Stock Exchange under the symbol "TMR." The following table sets forth, for the periods indicated, the high and low sale prices per share for the Common Stock as reported on the New York Stock Exchange:

	HIGH	LOW
2002:		
First quarter	$ 4.99	$ 3.01
Second quarter	4.94	2.80
Third quarter	3.70	2.05
Fourth quarter	2.28	0.50
2001:		
First quarter	$ 9.31	$ 6.40
Second quarter	7.98	6.10
Third quarter	6.93	2.65
Fourth quarter	4.30	3.02

The closing sale price of the Common Stock on March 18, 2003, as reported on the New York Stock Exchange Composite Tape, was $1.24. As of March 18, 2003, we had approximately 816 shareholders of record.

Meridian has not paid cash dividends on the Common Stock and does not intend to pay cash dividends on the Common Stock in the foreseeable future. We currently intend to retain our cash for the continued development of our business, including exploratory and development drilling activities. We also are currently restricted under our Credit Agreement from expending more than $2.0 million in the aggregate for cash dividends on the Common Stock or for purchase of shares of Common Stock without the prior consent of the lender.

ITEM 6. SELECTED FINANCIAL DATA

All financial data should be read in conjunction with our Consolidated Financial Statements and related notes thereto included throughout this report.

	YEAR ENDED DECEMBER		
	2002	2001	2000
	(In thousands, except prices and per		
A. SUMMARY OF OPERATING DATA			
Production:			
Oil (MBbls)	2,213	2,918	3,987
Natural gas (MMcf)	15,578	22,085	27,672
Natural gas equivalent (MMcfe)	28,856	39,594	51,596
Average Prices:			
Oil ($/Bbl)	$ 24.67	$ 25.17	$ 27.32
Natural gas ($/Mcf)	3.36	4.67	4.14
Natural gas equivalent ($/Mcfe)	3.71	4.46	4.33
B. SUMMARY OF OPERATIONS			
Total revenues	$ 107,470	$ 178,060	$ 226,246
Depletion and depreciation	60,972	67,450	69,648
Net earnings (loss)(1)	(52,012)	22,551	65,070
Net earnings (loss) per share:(1)			
Basic	$ (1.05)	$ 0.47	$ 1.34
Diluted	(1.05)	0.43	1.06
Dividends per:			
Common share	--	--	--
Redeemable preferred share	$ 5.90	--	--
Preferred share	$	$ 0.11	$ 1.36
Weighted average common shares outstanding	49,763	48,350	48,646
C. SUMMARY BALANCE SHEET DATA			
Total assets	$ 456,240	$ 507,900	$ 570,921
Long-term obligations, inclusive of current maturities	203,750	210,000	250,000
Redeemable preferred stock	69,690	--	--
Stockholders' equity	133,393	188,221	270,322

(1) Applicable to common stockholders.

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

GENERAL

Meridian is an independent oil and natural gas company that explores for, acquires and develops oil and natural gas properties utilizing 3-D seismic technology. Our operations are focused on the onshore oil and gas regions in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico.

Our reserves and strategic acreage position provide us with a significant presence in our areas of focus, enabling us to manage a large asset base and to add successful exploratory and development wells at relatively low incremental costs. As of December 31, 2002, we had proved reserves of 167 Bcfe, approximately 64% of which were natural gas, with a present value of future pre-tax cash flows (PV-10) of $460 million. We own interests in approximately 299,000 gross (216,000 net) acres, including 25 fields and 138 wells, and we operate approximately 70% of our total production.

The Company's business model utilizing 3-D seismic technology to explore for large reserve accumulations in areas where others have overlooked or not encountered commercial hydrocarbons because of the inability to resolve structures or recognize hydrocarbon indicators with traditional 2-D seismic data, has prove successful. During the period of 1992-2002, Meridian generated and participated in the discovery of over 850 BCFE of natural gas and oil.

As demonstrated from the apparent declines in domestic production, fewer and fewer economic projects are being recognized by the domestic industry. This is partly a result of better technology that has improved the industry's ability to determine probabilities of success, thereby impacting the number of economic prospects available for drilling.

In addition, the conditions of the industry--price volatility and uncertainty as well as declining prospect opportunities--and the overall economy have influenced the availability of debt and equity capital for small capitalization companies such as Meridian. This, combined with the geological/geophysical and mechanical risks associated with drilling primarily deep, high-pressured wills with large working interests, has resulted in a shift in the Company's strategy for exploration. Recognizing the trend and risks resulting therefrom, beginning in 2001, management embarked on its current strategy to continue to utilize its application of 3-D seismic technology to generate and drill shallower, higher-confidence, lower-risk plays, such as its Biloxi Marshlands project in St. Bernard Parish, Louisiana, blended with its traditional deeper, higher risk, but higher potential opportunities where its capital expenditure budget permits.

We have a large, balanced inventory of exploration, exploitation and development drilling prospects in our producing region. In addition to a solid reserve base and acreage position in our area of focus, we believe we possess the technical knowledge and information necessary to sustain successful growth. With licenses and rights to over 7,500 square miles of 3-D seismic data and 155,000 linear miles of 2-D seismic data, our technical and professional staff is in a unique position to continue to generate future prospects for our growth.

Our Strategy. The key elements of our strategy are as follows:

- Generate reserve additions through exploration, exploitation and development drilling of a balanced portfolio of high potential prospects;

- When appropriate, oil and natural gas reserves will be purchased and/or disposed of when deemed beneficial. See Management Liquidity Plans on page 25.

- Maintain a concise geographic focus applying professional and technical knowledge and experience to the development of a high quality project inventory;

- Apply a disciplined methodology utilizing 3-D seismic technology to reduce exploration risk, improve the probability of success, optimize well locations and reduce our finding costs;

- Maximize percentage ownership in each drilling prospect relative to probability of success, increasing the impact of discoveries on shareholder value; and

- Maintain operational control to manage quality, costs and timing of our drilling and production activities.

We use a disciplined approach in the generation of drilling projects, which forms the basis of the Company's ability to grow its reserves, production and cash flow. The Company's process of review begins with a thorough analysis of each project area using traditional geological methods of prospect development, combined with computer-aided technology to analyze all available 2-D and 3-D seismic data and other geological and geophysical data with respect to the opportunity. In addition, from time to time, we may purchase producing properties through acquisitions that have substantial additional drilling opportunities associated with them.

The Company has forecasted between $15 million and $20 million in capital expenditures for 2003, subject to adjustment depending on drilling results, the number of wells drilled, drilling conditions and other factors. The 2003 expenditures will be spent primarily on the development of its recently acquired Biloxi Marshlands exploration/exploitation play in south Louisiana. Should additional funding be obtained, 2003 capital expenditures could be increased by $15 million to $20 million.

Recent Developments. As previously announced, Meridian successfully completed its Biloxi Marshlands 6-1 well, located in St. Bernard Parish, Louisiana during the fourth quarter of 2002. The well reached a total depth of 10,800' measured depth (9,000' TVD) and encountered over 180' of net pay in the targeted Cris "I" sand. The well was placed on production on March 15, 2003, and is currently producing at a gross rate of approximately 11,000 Mcf per day, which represents an increase of approximately 10% of current daily production. During March 2003, the Company participated in the State of Louisiana oil and gas lease sale, and successfully bid on five additional tracts in the area covering approximately 740 acres in and around this play. The Company's working interest in the Biloxi Marshlands No. 6-1 well is 93% (net revenue interest is 69%). Several additional development and exploratory wells are planned in the area during 2003.

Following the drilling of the Biloxi Marshlands 6-1 well, the Company constructed a barge based production facility and installed approximately five miles of 8" pipeline capable of processing and transporting the production from the current well and future wells on the Biloxi Marshland acreage.

Meridian expects to begin the second phase of its 3-D seismic program on the

Biloxi Marshlands acreage during April 2003. The survey will encompass at least 105 square miles and is expected to be complete during the third quarter of 2003.

The Hughes No. 2 well in Jefferson Davis Parish, Louisiana has been drilled to a total depth of 17,850' measured depth and a completion in the Bol Mex 5 sand series is currently underway. The well is a replacement for the Hughes No. 1 that experienced cementing problems during the completion phase and was subsequently abandoned. During February 2003, the Company completed the construction of production facilities for the Hughes No. 2 and is currently conducting final completion operations on the well. Because of the small wellbore at depth (5 1/2") and the difficulties experienced with the cementing of the casing in the Hughes No. 1 well, the Company attempted an open hole completion. This attempt was not a successful as desired but did not preclude future alternative methods of completion. It is currently planned to clean out the bore and to complete the well under more traditional methods. Meridian is the operator of the well and owns an approximate 94% working interest and a 70% net revenue interest in the well.

Also in Jefferson Davis Parish, Louisiana, in the Company's Thornwell field, Meridian participated in the drilling of the Blank Living Trust well, which encountered 20' of pay at a depth of 11,960'. The well was placed on production flowing at a rate of 9,000 Mcfe and 183 barrels of oil per day during the fourth quarter of 2002. This field continues to generate new drill sites beyond early expectations. The Company has identified several additional amplitude anomalies which it expects to include in our drilling program for 2003. The Company owns an approximate 26% working interest and a 17% net revenue interest in the well.

Recompletion operations are expected to be underway on the Thibodaux No. 1 well in the Company's Ramos Field within the next 30-45 days. Once recompleted to the Operc 3 interval, the Company expects the well to produce at rates of 10,000 Mcfe per day or more. Meridian is operator of the Ramos Field and owns a 65% working interest and a 44% net revenue interest in the well.

In the Lakeside Field located in Cameron Parish, Louisiana, Meridian completed its Lacassane No. 1 well in the 13' thick Alliance sand at a depth of approximately 10,750'. The well initially tested at rates of 1,425 Mcfe of gas per day from the lower part of the sand and additional perforations are now being added to include the thicker upper member. The Company owns a 73% working interest (47% net revenue interest) in the well.

The capital expenditure budget for 2003 is currently forecast between $15 million and $20 million for seismic and drilling activity, primarily focused in the Biloxi Marshlands project area. The first development well is the Biloxi Marshlands 6-2 well which is scheduled for April 2003. Other operations are expected to include a 12,500' well in Ship Shoal Block 320, and certain other shallow, lower risk opportunities including additional wells in the Biloxi Marshlands project area. As previously announced, the Company has changed its exploration focus to concentrate on multiple shallower, low risk projects with broad exploitation/development potential interspersed with one or more of the Company's traditional higher risk, but much higher potential, projects.

Industry Conditions. Our revenues, profitability and cash flow are substantially dependent upon prevailing prices for oil and natural gas. Oil and natural gas prices have been extremely volatile in recent years and are

affected by many factors outside of our control. The average price we received during the year ended December 31, 2002 was $3.71 per Mcfe compared to $4.46 per

Mcfe during the year ended December 31, 2001. Fluctuations in prevailing prices for oil and natural gas have several important consequences to us, including affecting the level of cash flow received from our producing properties, the timing of exploration of certain prospects and our access to capital markets, which could impact our revenues, profitability and ability to maintain or increase our exploration and development program. Refer to Item 7.a. for a discussion of commodity price risk management activities utilized to mitigate a portion of the near term effects of this exposure to price volatility.

Full Cost Ceiling Write-down. During 2002, a negative revision in oil and natural gas proved undeveloped reserves associated with the Kent Bayou Field resulted in the Company recognizing a full cost ceiling write-down totaling $69.1 million ($46.9 million after tax) of its oil and natural gas properties. A decline in oil and natural gas prices caused us to recognize $6.6 million in full cost ceiling write-downs during 2001. Due to the potential volatility in oil and gas prices and their effect on the carrying value of our proved oil and gas reserves, there can be no assurance that future write-downs will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas reserves and the carrying value of oil and natural gas properties, including volatile oil and natural gas prices, downward revisions in estimated proved oil and natural gas reserve quantities and unsuccessful drilling activities.

RESULTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2002, COMPARED TO YEAR ENDED DECEMBER 31, 2001

Oil and natural gas revenues decreased $69.6 million as a result of decreased production volumes and a decrease in average commodity prices. The production decrease was primarily a result of the property sales completed during 2001, hurricane related production losses and natural production declines, partially offset by the inclusion of new wells being placed on production. The following table summarizes Meridian's operating revenues, production volumes and average sales prices for the years ended December 31, 2002 and 2001.

	Year Ended December 31, 2002	Year Ended December 31, 2001
Production:		
Oil (MBbls)	2,213	2,918
Natural gas (MMcf)	15,578	22,085
Natural gas equivalent (MMcfe)	28,856	39,594
Average Sales Price:		
Oil (per Bbl)	$ 24.67	$ 25.17
Natural gas (per Mcf)	3.36	4.67
Natural gas equivalent (per Mcfe)	3.71	4.46
Gross Revenues (000's):		
Oil	$ 54,595	$ 73,443
Natural gas	52,397	103,203
Total	$106,992	$176,646

Interest and Other Income.

Interest and other income decreased $0.9 million to $0.5 million in 2002, compared to $1.4 million for 2001. This decrease was primarily due to a lower average amount of invested funds and lower interest rates during 2002 than in 2001. A significant portion of the interest income for 2001 was earned on the investment of funds accumulated from the sale of properties and a Common Stock offering during 2000. These funds had been accumulated to exercise the option to buy back the Company's Preferred Stock and six million shares of the Company's Common Stock from Shell on January 29, 2001.

Operating Expenses.

Oil and natural gas operating expenses decreased $4.7 million to $11.9 million in 2002, compared to $16.6 million in 2001. This decrease was primarily due to the sale of high cost, non-core properties during 2001 and the reorganization of field operations over the last thirteen months partially offset by the inclusion of costs associated with returning the Company's properties to production following hurricanes. This reorganization involved a reduction in field operating personnel and increased emphasis on operating cost reductions. In addition, the Company undertook an expanded well workover program during 2001 in order to benefit from the higher commodity prices being realized at the time.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes decreased $3.6 million to $8.2 million in 2002, compared to $11.8 million in 2001. This decrease is largely attributable to the decrease in natural gas production and the decrease in oil revenues from the 2001 levels, partially offset by an increase in the average tax rate for natural gas. Meridian's production is primarily from southern Louisiana, and, therefore, is subject to a current tax rate of 12.5% of gross oil revenues and $0.122 per Mcf for natural gas. The tax rate for natural gas for the first half of 2001 was $0.097 per Mcf and from July 2001 through June 2002 was $0.199 per Mcf.

Depletion and Depreciation.

Depletion and depreciation expense decreased $6.4 million to $61.0 million in 2002 from $67.4 million for 2001. This decrease was primarily a result of the 27% decrease in production on an Mcfe basis from 2001, partially offset by an increase in the depletion rate from 2001 levels primarily due to the write-down of the proved reserves associated with the Kent Bayou Field.

General and Administrative Expense.

General and administrative expense decreased $1.7 million to $11.8 million in 2002 compared to $13.5 million for the year 2001. This reduction was primarily due to the savings realized from staff reductions and the purchase and termination of certain outstanding well bonus plan interests at the end of 2001.

Interest Expense.

Interest expense decreased $5.8 million to $14.3 million in 2002 compared to $20.1 million for 2001. The decrease is primarily a result of the reduction in the debt balance and the Federal Reserve Bank's decrease in overall interest rates which has led to a decrease in the average interest rate on the revolving credit facilities.

Full Cost Ceiling Writedown.

During 2002, a negative revision in oil and natural gas proved undeveloped reserves associated with an unsuccessful well drilled in the Kent Bayou Field resulted in the Company recognizing a full cost ceiling write-down totaling $69.1 million ($46.9 million after tax) of its oil and natural gas properties.

A decline in oil and natural gas prices caused us to recognize $6.6 million in full cost ceiling write-downs during 2001.

Credit Facility Retirement Costs.

During 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a new three-year $175 million underwritten senior secured credit agreement with Societe Generale and Fortis Capital Corp. Deferred debt costs associated with the prior credit facility of $1.2 million were written off in 2002.

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YEAR ENDED DECEMBER 31, 2001, COMPARED TO YEAR ENDED DECEMBER 31, 2000

Operating Revenues and Production.

Oil and natural gas revenues decreased $46.8 million as a result of decreased production volumes partially offset by improved commodity prices. The production decrease was primarily a result of the property sales in 2001 and 2000 and natural production declines, partially offset by the inclusion of new wells being placed on production. The following table summarizes Meridian's operating revenues, production volumes and average sales prices for the years ended December 31, 2001 and 2000.

	Year Ended December 31, 2001	Year Ended December 31, 2000	Increase (Decrease)
Production:			
Oil (MBbls)	2,918	3,987	(27%)
Natural gas (MMcf)	22,085	27,672	(20%)
Natural gas equivalent (MMcfe)	39,594	51,596	(23%)
Average Sales Price:			
Oil (per Bbl)	$ 25.17	$ 27.32	(8%)
Natural gas (per Mcf)	4.67	4.14	13%
Natural gas equivalent (per Mcfe)	4.46	4.33	3%
Gross Revenues (000's):			
Oil	$ 73,443	$ 108,930	(33%)
Natural gas	103,203	114,490	(10%)
Total	$176,646	$ 223,420	(21%)

Interest and Other Income.

Interest and other income decreased $1.4 million to $1.4 million in 2001, compared to $2.8 million for 2000. This decrease was primarily due to invested funds during 2000 from the sale of properties and the Common Stock offering that was being accumulated for the amount required to exercise the option to buy back the Company's Preferred Stock and six million shares of the Company's Common Stock from Shell in January 2001.

Operating Expenses.

Oil and natural gas operating expenses decreased $1.6 million to $16.6 million in 2001, compared to $18.2 million in 2000. This decrease was primarily due to the decrease in the number of wells from the sale of high cost, non-core properties and reorganization of field operation resulting in greater efficiencies partially offset by non-recurring expenses from an expanded well workover program and higher lifting costs on marginal wells.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes decreased $3.8 million to $11.8 million in 2001, compared to $15.6 million in 2000. This decrease is largely attributable to the decrease in production from 2000 levels partially offset by an increase in the tax rate for natural gas. Meridian's production is primarily from southern Louisiana, and, therefore, is subject to a current tax rate of 12.5% of gross oil revenues and $0.199 per Mcf for natural gas. The tax rate for natural gas for the first half of 2000 was $0.078 per Mcf and from July 2000 through June 2001 was $0.097 per Mcf.

Depletion and Depreciation.

Depletion and depreciation expense decreased $2.2 million to $67.4 million in 2001 from $69.6 million for 2000. This decrease was primarily a result of the 23% decrease in production on an Mcfe basis from 2000, partially offset by an increase in the depletion rate, reflecting the sale of non-core properties.

General and Administrative Expense.

General and administrative expense decreased $2.9 million to $13.5 million in 2001 compared to $16.4 million for the year 2000. This decrease was primarily a result of staff reductions and decreases in salaries, wages, and other compensation related to the provisions of the 1998 net profits and well bonus plans. The plans provide for bonus payments to employees, which are calculated using a formula derived from the actual net profits on each well in the plan for the previous year. Decreased payouts in 2001 have resulted primarily due to decreased production volumes and the purchase and termination of certain well bonus plans during the latter portion of the year.

Interest Expense.

Interest expense decreased $5.4 million to $20.1 million in 2001 compared to $25.5 million for 2000. The decrease is primarily a result of the overall reduction in debt and the Federal Reserve Bank's decrease in overall interest rates which has led to a decrease in the average interest rate on the credit facility.

LIQUIDITY AND CAPITAL RESOURCES

WORKING CAPITAL. As of December 31, 2002, we had a cash balance of $7.3 million and a working capital deficit of $47.1 million. The Company is evaluating a number of opportunities to raise additional funds.

A part of the Company's focus is to satisfy our immediate funding obligations under our various debt agreements and to implement a plan that will accomplish an orderly reduction and restructuring of our debt capital, while taking advantage of the strong asset base built over the years. As a part of the restructuring and ultimate reduction of our debt, it is our intent to add future reserves primarily through low risk, 3-D based drilling while maintaining a disciplined approach to costs.

CREDIT FACILITY.

During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a new three-year $175 million underwritten senior secured credit agreement (the "Credit Agreement") with Societe Generale, as administrative agent, lead arranger and book runner, and Fortis Capital Corp., as co-lead arranger and documentation agent. Deferred debt costs associated with the prior credit facility of $1.2 million were written off in September 2002. The current borrowing base under the existing Credit Agreement was established on September 23, 2002, at $165 million, with the borrowing base redetermination date scheduled for November 30, 2002. The parties to the Credit Agreement have entered into an amendment of the Agreement, effective March 31, 2003, to eliminate the November 30, 2002, redetermination date and to reschedule the borrowing base redetermination date for April 30, 2003, and quarterly redetermination thereafter. The current borrowing base is $165 million, which is the same as that established upon the signing of the original Credit Agreement.

On March 31, 2003, the Company received notice from its senior lenders that effective April 30, 2003 the borrowing base will be established at $138.5 million. Accordingly, the Company has reflected the difference of $26.5 million as a current maturity of its long-term debt and will be required to make up the deficiency through the addition of reserves or value to its current reserve base or pay the senior lenders this deficiency within 90 days of the effective date of April 30, 2003. Though no assurances can be made that sufficient funds will be available to pay this deficiency, management believes that it can satisfy this deficiency through a combination of the addition of reserves, third-party financing, property sales and cash flow. See Management Liquidity Plans on page 25 for further discussion.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders under the Credit Agreement have the right to redetermine the borrowing base at any time once during each calendar year and the Company has the right to obtain a redetermination by the banks of the borrowing base once during each calendar year. Borrowings under the Credit Agreement are secured by pledges of outstanding capital stock of the Company's subsidiaries and a mortgage on the Company's oil and natural gas properties of at least 90% of its present value of proved properties. The Credit Agreement contains various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock and an unqualified audit report on the Company's consolidated financial statements beginning with those as of and for the year ended December 31, 2002. The Company has received from the senior lenders a waiver of the covenant that would have triggered an event of default as a result of the independent auditors' report which contained a "going concern" modification for our 2002 consolidated financial statements. Borrowings under the Credit Agreement mature on August 13, 2005.

Under the new Credit Agreement, the Company may secure either (i) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate plus an additional 0.5% to 1.5% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base; or a federal funds-based rate plus 1/2 of 1% or (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate ("LIBOR") plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Credit Agreement also provides for commitment fees ranging from 0.375% to 0.5% per annum.

SUBORDINATED CREDIT AGREEMENT. The Company extended and amended a short-term subordinated credit agreement with Fortis Capital Corporation for $25 million on April 5, 2002, with a maturity date of December 31, 2004. The interest rate is the LIBOR plus 4.5% through December 31, 2002, LIBOR plus 5.5% from January 1, 2003, through August 31, 2003, and LIBOR plus 6.5% from September 1, 2003, through December 31, 2004. Note payments of $5 million each are due on August 31, 2003, and April 30, 2004, with the remaining $5 million payable on December 31, 2004. Note payments totaling $6.25 million were paid in 2002, with an additional $1.25 million being paid in January 2003. An additional $2.5 million that is currently due has been deferred in conjunction with the March 31, 2003, amendment to the Credit Agreement. No amounts are payable under this subordinated debt until any and all borrowing base deficiencies under the Credit Agreement are satisfied.

9 1/2% CONVERTIBLE SUBORDINATED NOTES. During June 1999, we completed private placements of an aggregate of $20 million of our 9 1/2% Convertible Subordinated Notes due June 18, 2005 (the "Notes"). The Notes are unsecured and contain customary events of default, but do not contain any maintenance or other restrictive covenants. Interest is payable on a quarterly basis.

During March 2002, the Company and the holders of the Notes amended the conversion price from $7.00 to $5.00 per share. The Notes are convertible at any time by the holders of the Notes into shares of the Company's Common Stock, $0.01 par value utilizing the conversion price. The conversion price is subject to customary anti-dilution provisions. The holders of the Notes have been granted registration rights with respect to the shares of Common Stock that would be issued upon conversion of the Notes or issuance of the warrants discussed below. We may prepay the Notes at any time without penalty or premium.

MANAGEMENT LIQUIDITY PLANS. As noted in our discussion of the Credit Facility, there will be a $26.5 million borrowing base deficiency at April 30, 2003 that must be satisfied by either sufficient additions to our proved reserves or repayment on or before July 29, 2003 to avoid an event of default. An event of default which is not cured results in the entire debt outstanding becoming due and payable, unless it is waived by the senior lenders or the Credit Agreement is otherwise amended. Also, repayment of $2.5 million, after our $1.25 million January 2003 payment, under our subordinated debt agreement is due but is deferred pending satisfaction of the borrowing base deficiency under the amended Credit Agreement. The $5 million subordinated debt repayment that will become due in August 2003 is also subject to deferral for any borrowing base deficiencies that may exist at that time. The $34 million due in 2003 under these agreements represents a significant component of our $47.1 million working capital deficiency at December 31, 2002.

Based upon our expected level of production and considering a reduced level of capital spending plan of $15 to $20 million, we project that our available cash flow from operations is not expected to be sufficient to fund the April 30, 2003 borrowing base deficiency and amounts due or to become due in 2003 under our subordinated debt agreement. In order to address this liquidity issue and address the broader issue of aligning our capital structure with our long-term business strategy, the following plans to sell non-strategic oil and gas properties and secure new sources of capital through subordinated debt or similar financing arrangements have been initiated.

In an effort to address the liquidity issue and the broader issue of aligning our capital structure with our long-term business strategy, the Company is pursuing several plans that it believes will remedy the current borrowing base deficiency of $26.5 million.

First, it should be noted that, as of December 31, 2002, the Company's proved developed reserves have a present value based on SEC regulations that include prices in effect at year-end and a 10% discount rate, of approximately $460 million or approximately three (3) times its total senior credit facility.

Based on current cash flow projections and the Company's specific knowledge of its drilling prospects and historical performance in the areas of anticipated activity, potential opportunities for non-strategic property sales and/or third party capital funding, it is management's judgment and belief that its business plan will provide the Company with the means to meet the required coverage for the new borrowing base by a combination of newly discovered reserves, proceeds from strategic sales of non-essential properties, where appropriate, and/or the infusion of third party capital in the form of sub-debt, all on or before July 31, 2003.

Currently, the Company has scheduled two (2) exploration and development wells that can be drilled and logged prior to July 31, 2003, barring mechanical or other issues out of the Company's control, such as permitting issues, weather or equipment availability. The Company believes that these wells together have the potential of adding reserves sufficient to remedy the borrowing base deficiency.

In addition, the Company has identified certain properties which are not essential to its future growth and which it is in the process of marketing on a limited basis. These include reserves of up to 100 BCFE and production of approximately 50 mmcfe/d having an SEC PV10 value of over $281 million. It is believed that a sale price of all or a sufficient portion of these properties can be achieved on or before July 31, 2003.

Further, the Company is in discussions with third parties regarding the infusion of capital of up to $45-50 million in the form of sub-debt capital. These discussions are subject to certain due diligence verification of the reserves, financial reported data and title examination as well as approval by the senior lenders. The proceeds will be used to reduce the current indebtedness of the senior credit facility as well as capital expenditures for calendar year 2003. It is anticipated that the due diligence can be concluded on or before April 30, 2003. Assuming positive results on both the due diligence and of the terms and conditions of the sub-debt facility by the senior lenders, it is anticipated that this transaction could close on or before July 31, 2003.

Although there can be no assurances, management is confident that sufficient proceeds from the sale of non-strategic oil and natural gas properties and new subordinated debt or similar financing arrangements will be generated in sufficient time to satisfy our funding obligations under both the Credit Agreement and the subordinated debt agreement to permit an orderly reduction and restructuring of our debt capital.

8.5% REDEEMABLE CONVERTIBLE PREFERRED STOCK. A private placement of $66.85 million of 8.5% redeemable convertible preferred stock was completed during May

2002. The preferred stock is convertible into shares of the Company's Common Stock at a conversion price of $4.75 per share. Dividends are payable semi-annually in cash or additional preferred stock. At the option of the Company, one-third of the preferred shares can be forced to convert to Common Stock if the closing price of the Company's Common Stock exceeds 150% of the conversion price for 30 out of 40 consecutive trading days on the New York Stock Exchange. Based on the above conversion criteria, the Company can elect to convert up to one-third of the original issue provided that the conversion occurs no sooner than twelve months from the most recent conversion. The preferred stock is subject to redemption at the option of the Company after March 2005, and mandatory redemption on March 31, 2009. The holders of the preferred stock have been granted registration rights with respect to the shares of Common Stock issued upon conversion of the preferred stock. Dividend payments of $1.1 million were paid during the third quarter of 2002. Dividends of $3.9 million were accumulated during 2002, of which $1.1 million was paid in cash and $2.8 million was satisfied with the issuance of additional shares of redeemable preferred stock.

CAPITAL EXPENDITURES. Capital expenditures in 2002 consisted of $76.8 million for property and equipment additions primarily related to exploration and development of various prospects, including leases, seismic data acquisitions, and drilling and workover activities. Our strategy is to blend exploration drilling activities with high-confidence workover and development projects selected from our broad asset inventory in order to capitalize on periods of high commodity prices. This strategy brought on production and added reserves sooner than the drilling of deep, higher risk exploration wells.

The 2003 capital expenditures plan is currently forecast between $15 and $20 million. The final projects will be determined based on a variety of factors, including prevailing prices for oil and natural gas, our expectations as to future pricing and the level of cash flow from operations. We currently anticipate funding the 2003 plan primarily utilizing cash flow from operations. Where appropriate, excess cash flow from operations as a result of increased rates or prices beyond that needed for the 2003 capital expenditures plan we will use to de-lever the Company by development of exploration discoveries or direct payment of debt.

SALE OF PROPERTIES. On May 17, 2001, the Company sold certain non-strategic oil and gas properties located in south Louisiana and the Texas Gulf Coast for approximately $30 million. The sale was comprised of approximately 25 Bcfe proved developed reserves and 24 Bcfe of undeveloped reserves. Benefits of the sale include the reduction of total debt by an additional $30 million resulting in an immediate savings in interest costs on the Company's senior bank debt, the elimination of $9.5 million in future capital expenditures associated with the properties, and the elimination of over $5 million in annual lease operating expenses. On December 20, 2001, we sold additional properties in south Louisiana for approximately $2.5 million.

CASH OBLIGATIONS. The following summarizes the Company's contractual obligations at December 31, 2002 and the effect such obligations are expected to have on its liquidity and cash flow in future periods (in

thousands):

	LESS THAN ONE YEAR	1-3 YEARS	AFTER 3 YEARS

Short and long term debt	$ 35,250	$ 168,500	$ --	$
Non-cancelable operating leases	1,554	3,243	1,230	
Total contractual cash obligations	$ 36,804	$ 171,743	$ 1,230	$

DIVIDENDS. It is our policy to retain existing cash for reinvestment in our business, and therefore, we do not anticipate that dividends will be paid with respect to the Common Stock in the foreseeable future. Dividends on the Redeemable Preferred Stock aggregating $3.9 million were accrued for in 2002. Of that amount, $1.1 million was paid in cash and $2.8 million was satisfied with the issuance of additional shares of redeemable preferred stock.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company's discussion and analysis of its financial condition and results of operation are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally adopted in the United States. The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the Consolidated Financial Statements.

USE OF ESTIMATES. The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities, if any, at the date of the financial statements. The Company analyzes its estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes and contingencies and litigation. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its consolidated financial statements.

PROPERTY AND EQUIPMENT. The Company follows the full cost method of accounting for its investments in oil and natural gas properties. All costs incurred with the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. Under the full cost method of accounting, such costs may be incurred both prior to or after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion and equipment. Included in capitalized costs are general and administrative costs that are directly related with acquisition, exploration and development activities, and which are not related to production, general corporate overhead or similar activities. For the years 2002, 2001, and 2000, such capitalized costs totaled $11.7 million, $13.5 million, and $14.5 million, respectively. General and administrative costs related to production and general overhead are expensed as incurred.

Proceeds from the sale of oil and natural gas properties are credited to the full cost pool, except in transactions involving a significant quantity of reserves or where the proceeds received from the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss would be recognized.

Future development, site restoration, and dismantlement and abandonment costs, net of salvage values, are estimated property by property based upon current economic conditions and are included in our amortization of our oil and natural gas property costs.

The provision for depletion and amortization of oil and natural gas properties is computed by the unit-of-production method. Under this computation, the total unamortized costs of oil and natural gas properties (including future development, site restoration, and dismantlement and abandonment costs, net of salvage value), excluding costs of unproved properties, are divided by the total estimated units of proved oil and natural gas reserves at the beginning of the period to determine the depletion rate. This rate is multiplied by the physical units of oil and natural gas produced during the period.

The cost of unevaluated oil and natural gas properties not being amortized is assessed quarterly to determine whether such properties have been impaired. In determining impairment, an evaluation is performed on current drilling results, lease expiration dates, current oil and gas industry conditions, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

FULL-COST CEILING TEST. At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using unhedged period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties adjusted for related income tax effects.

The calculation of the ceiling test and the provision for depletion and amortization is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgement. Results of drilling, testing, and production subsequent to the date of the estimate may justify a revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

During 2002, a negative revision in oil and natural gas proved undeveloped reserves associated with the Kent Bayou Field resulted in the Company recognizing a full cost ceiling write-down totaling $69.1 million ($46.9 million after tax) of its oil and natural gas properties. A decline in oil and natural gas prices caused us to recognize $6.6 million in full cost ceiling write-downs during 2001. Due to the inherent imprecision in estimating oil and natural gas revenues as well as the potential volatility in oil and gas prices and their effect on the carrying value of our proved oil and gas reserves, there can be no assurance that write-downs in the future will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas reserves and the carrying value of oil and natural gas properties, including volatile oil and natural gas prices, downward revisions in estimated proved oil and natural gas reserve quantities and unsuccessful drilling activities.

PRICE RISK MANAGEMENT ACTIVITIES. The Company follows the Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" which requires that changes in the derivatives fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument be reported in the balance sheet as either an asset or liability measured at its fair value. Special hedge accounting for qualifying hedges allow the gains and losses on derivatives to offset related results on the hedged item in the earnings statements and would require that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. We adopted FAS 133 effective January 1, 2001.

The Company's results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, the Company has entered

into various swap agreements. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

These swaps have been designated as cash flow hedges as provided by FAS 133 and any changes in fair value of the cash flow hedge resulting from ineffectiveness of the hedge is reported in the consolidated statement of operation as revenues.

The estimated December 31, 2002, fair value of the Company's oil and natural gas swaps is an unrealized loss of $7.3 million ($4.8 million net of tax) recognized in other comprehensive income. Based upon December 31, 2002, oil and natural gas commodity prices, approximately $5.9 million of the loss deferred in other comprehensive income is expected to lower gross revenues over the next twelve months when the revenues are generated. The swap agreements expire at various dates through July 31, 2005.

Payments under these swap agreements reduced oil and natural gas revenues by $1,183,000 for the year ended December 31, 2002. During the year ended December 31, 2001, the Company had no material open hedging agreements. During the year ended December 31, 2000, payments under swap agreements reduced oil and natural gas revenues by $5,419,000.

See Item 7.a. for additional discussion of disclosures about market risk.

FAIR VALUE OF FINANCIAL INSTRUMENTS. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings and subordinated notes. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2002 and 2001, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair values of our subordinated notes due 2005 were $18.9 million and $20.0 million at December 31, 2002 and 2001, respectively. The carrying value of our subordinated notes was $20 million at December 31, 2002 and 2001.

FORWARD-LOOKING INFORMATION

From time to time, we may make certain statements that contain "forward-looking" information as defined in the Private Securities Litigation Reform Act of 1995 and that involve risk and uncertainty. These forward-looking statements may include, but are not limited to exploration and seismic acquisition plans, anticipated results from current and future exploration prospects, future capital expenditure plans, anticipated results from third party disputes and litigation, expectations regarding compliance with our credit facility, the anticipated results of wells based on logging data and production tests, future sales of production, earnings, margins, production levels and costs, market trends in the oil and natural gas industry and the exploration and development sector thereof, environmental and other expenditures and various business trends. Forward-looking statements may be made by management orally or in writing including, but not limited to, the Management's Discussion and Analysis of Financial Condition and Results of Operations section and other sections of our filings with the Securities and Exchange Commission under the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended.

Actual results and trends in the future may differ materially depending on a variety of factors including, but not limited to the following:

Changes in the price of oil and natural gas. The prices we receive for our oil and natural gas production and

the level of such production are subject to wide fluctuations and depend on numerous factors that we do not control, including seasonality, worldwide economic conditions, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Material declines in the prices received for oil and natural gas could make the actual results differ from those reflected in our forward-looking statements.

Operating Risks. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial position and results of operations. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including uncontrollable flows of oil, natural gas, brine or well fluids into the environment (including groundwater and shoreline contamination), blowouts, cratering, mechanical difficulties, fires, explosions, unusual or unexpected formation pressures, pollution and environmental hazards, each of which could result in damage to or destruction of oil and natural gas wells, production facilities or other property, or injury to persons. In addition, we are subject to other operating and production risks such as title problems, weather conditions, compliance with government permitting requirements, shortages of or delays in obtaining equipment, reductions in product prices, limitations in the market for products, litigation and disputes in the ordinary course of business. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against certain of these risks either because such insurance is not available or because of high premium costs. We cannot predict if or when any such risks could affect our operations. The occurrence of a significant event for which we are not adequately insured could cause our actual results to differ from those reflected in our forward-looking statements.

Drilling Risks. Our decision to purchase, explore, develop or otherwise exploit a prospect or property will depend in part on the evaluation of data obtained through geophysical and geological analysis, production data and engineering studies, which are inherently imprecise. Therefore, we cannot assure you that all of our drilling activities will be successful or that we will not drill uneconomical wells. The occurrence of unexpected drilling results could cause the actual results to differ from those reflected in our forward-looking statements.

Uncertainties in Estimating Reserves and Future Net Cash Flows. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas we cannot measure in an exact manner, and the accuracy of any reserve estimate is a function of the quality of those accumulations of data and of engineering and geological interpretation and judgement. Reserve estimates are inherently imprecise and may be expected to change as additional information becomes available. There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Because all reserve estimates are to some degree speculative, the quantities of oil and natural gas that we ultimately recover, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Significant downward revisions to our existing reserve estimates could cause the actual results to differ from those reflected in our forward-looking statements.

Borrowing base for the Credit Facility. The Credit Agreement with Societe Generale and Fortis Capital Corp. is presently scheduled for borrowing base redetermination dates on a quarterly basis beginning April 30, 2003. The borrowing base is redetermined on numerous factors including current reserve estimates, reserves that have recently been added, current commodity prices, current production rates and estimated future net cash flows. These factors have associated risks with each of them. Significant reductions or increases in the borrowing base will be determined by these factors, which, to a significant extent, are not under the Company's control.

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

The Company is from time to time exposed to market risk from changes in interest rates and hedging contracts. A discussion of the market risk exposure in financial instruments follows.

INTEREST RATES

We are subject to interest rate risk on our long-term fixed interest rate debt and variable interest rate borrowings. Our long-term borrowings primarily consist of borrowings under the Credit Facility and principal due December 31, 2004 under our Subordinated Credit Agreement. Since interest charged borrowings under the Credit Facility floats with prevailing interest rates (except for the applicable interest period for Eurodollar loans), the carrying value of borrowings under the Credit Facility should approximate the fair market value of such debt. Changes in interest rates, however, will change the cost of borrowing. Assuming $183.7 million remains borrowed under the Credit Facility and $10 million remains borrowed under the Subordinated Credit Agreement, we estimate our annual interest expense will change by $1.838 million for each 100 basis point change in the applicable interest rates utilized under the Credit Facility and $10 million from the Subordinated Credit Agreement. Changes in interest rates would, assuming all other things being equal, cause the fair market value of debt with a fixed interest rate, such as the Notes, to increase or decrease, and thus increase or decrease the amount required to refinance the debt. The fair value of the Notes is dependent on prevailing interest rates and our current stock price as it relates to the conversion price of $5.00 per share of our Common Stock.

HEDGING CONTRACTS

Meridian may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. From time to time, we may enter into swaps and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at or prior to expiration or exchanged for physical delivery contracts. Meridian does not obtain collateral to support the agreements, but monitors the financial viability of counter-parties and believes its credit risk is minimal on these transactions. In the event of nonperformance, we would be exposed to price risk. Meridian has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction.

In 2002, we entered into certain swap agreements as summarized in the table below. The Notional Amount is equal to the total net volumetric hedge position of Meridian during the periods indicated. The positions effectively hedge approximately 44% of our proved developed natural gas production and 70% of our proved developed oil production. The fair values of the hedges are based on the difference between the strike price and the New York Mercantile Exchange future prices for the applicable trading months.

	Notional Amount	Weighted Average Strike Price ($ per unit)	Fair Value (unreal at December 31, 200 thousands)
Natural Gas (mmbtu)			
January 2003 - June 2005	8,610,000	$ 3.80	$ 4,721
Oil (bbls)			
January 2003 - July 2005	3,320,000	$ 24.55	$ 2,592
			$ 7,313

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The definitions set forth below apply to the indicated terms commonly used in the oil and natural gas industry and in this Form 10-K. Mcfe is calculated using the ratio of six Mcf of natural gas to one barrel of oil, condensate or natural gas liquids, which approximates the relative energy content of crude oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been substantially higher for crude oil than natural gas on an energy equivalent basis. Any reference to net wells or net acres was determined by multiplying gross wells or acres by our working percentage interest therein.

"Bbl" means barrel and "Bbls" means barrels.

"Bcf" means billion cubic feet.

"Bcfe" means billion cubic feet of natural gas equivalent.

"Btu" means British Thermal Unit.

"EPA" means Environmental Protection Agency.

"FERC" means the Federal Energy Regulatory Commission.

"MBbls" means thousand barrels.

"Mcf" means thousand cubic feet.

"Mcfe" means thousand cubic feet of natural gas equivalent.

"MMBbls" means million barrels.

"MMBtu" means million Btus.

"MMcf" means million cubic feet.

"MMcfe" means million cubic feet of natural gas equivalent.

"NGPA" means the Natural Gas Policy Act of 1978, as amended.

"Present Value of Future Net Cash Flows" or "Present Value of Proved Reserves" means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

"Tcf" means trillion cubic feet.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

REPORT OF INDEPENDENT AUDITORS

Board of Directors and Stockholders
The Meridian Resource Corporation

We have audited the accompanying consolidated balance sheets of The Meridian Resource Corporation and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Meridian Resource Corporation and subsidiaries at December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 5 to the 2002 financial statements, the Company's working capital deficiency, including amounts due under its revolving credit agreement as a result of a borrowing base redetermination effective April 30, 2003, and the provisions in that agreement for additional redeterminations of the borrowing base during 2003, raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 5. The financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty.

ERNST & YOUNG LLP

Houston, Texas
April 8, 2003, except for Note 4,
as to which the date is April 15, 2003

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(thousands, except per share)

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
REVENUES:			
Oil and natural gas	$ 106,992	$ 176,646	$ 223,420
Interest and other	478	1,414	2,826
	107,470	178,060	226,246
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	11,935	16,625	18,234
Severance and ad valorem taxes	8,235	11,761	15,578
Depletion and depreciation	60,972	67,450	69,648
General and administrative	11,820	13,506	16,383
Issuance of stock grants	--	5,566	--
Impairment of long-lived assets	69,124	6,580	--
	162,086	121,488	119,843
EARNINGS (LOSS) BEFORE INTEREST AND INCOME TAXES	(54,616)	56,572	106,403
OTHER EXPENSES:			
Interest expense	14,253	20,092	25,533
Credit facility retirement costs	1,202	--	--
EARNINGS (LOSS) BEFORE INCOME TAXES	(70,071)	36,480	80,870
INCOME TAXES:			
Current	298	(300)	1,900
Deferred	(22,300)	13,800	8,500
	(22,002)	13,500	10,400
NET EARNINGS (LOSS)	(48,069)	22,980	70,470
DIVIDENDS ON PREFERRED STOCK	3,943	429	5,400
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ (52,012)	$ 22,551	$ 65,070
NET EARNINGS (LOSS) PER SHARE:			
Basic	$ (1.05)	$ 0.47	$ 1.34
Diluted	$ (1.05)	$ 0.43	$ 1.06
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Outstanding	49,763	48,350	48,646
Assuming dilution	49,763	55,842	67,521

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(thousands of dollars)

	DECEMBER 31, 2002	2001
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,287	$ 1
Accounts receivable, less allowance for doubtful accounts $833 [2002] and $891 [2001]	24,167	2
Due from affiliates	1,557	
Prepaid expenses and other	2,221	
Assets from price risk management activities	604	
Total current assets	35,836	4
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $18,993 [2002] and $30,247 [2001] not subject to depletion)	1,162,436	1,08
Land	478	
Equipment	9,913	
	1,172,827	1,09
Less accumulated depletion and depreciation	761,854	63
Total property and equipment, net	410,973	46
OTHER ASSETS:		
Assets from price risk management activities	292	
Deferred tax asset	2,560	
Other	6,579	
Total other assets	9,431	
Total assets	$ 456,240	$ 50

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(thousands of dollars)

		DECEMBER 31,	
	2002		
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES:			
Accounts payable	$ 16,842		$
Revenues and royalties payable	12,378		
Notes payable	831		
Accrued liabilities	9,958		
Liabilities from price risk management activities	6,781		
Current income taxes payable	931		
Current portion long-term debt	35,250		
Total current liabilities	82,971		
LONG-TERM DEBT	148,500		
9 1/2% CONVERTIBLE SUBORDINATED NOTES	20,000		
OTHER:			
Liabilities from price risk management activities	1,686		
Deferred income taxes	--		
	1,686		
REDEEMABLE PREFERRED STOCK:			
Preferred stock, $1.00 par value (1,500,000 shares authorized, 696,900 shares of Series C Redeemable Convertible Preferred Stock issued at stated value)	69,690		
STOCKHOLDERS' EQUITY:			
Common stock, $0.01 par value (200,000,000 shares authorized, 53,868,343 [2002] and 53,866,694 [2001] issued)	557		
Additional paid-in capital	378,215		
Accumulated deficit	(209,738)		
Accumulated other comprehensive loss	(4,938)		
Unamortized deferred compensation	(356)		
	163,740		
Less treasury stock, at cost (3,779,225 shares [2002] and 5,892,342 [2001] shares)	30,347		
Total stockholders' equity	133,393		
Total liabilities and stockholder's equity	$ 456,240		$

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(thousands of dollars)

	YEAR ENDED DECEMBER 31,		
	2002	2001	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings (loss)	$ (48,069)	$ 22,980	$
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depletion and depreciation	60,972	67,450	
Amortization of other assets	2,382	2,070	
Non-cash compensation	1,630	7,605	
Credit facility retirement costs	1,202	--	
Impairment of long-lived assets	69,124	6,580	
Deferred income taxes	(22,300)	13,800	
Changes in assets and liabilities:			
Accounts receivable	(58)	11,964	
Due from affiliates	(713)	(1,600)	
Prepaid expenses and other	(396)	(722)	
Accounts payable	(19,110)	18,119	
Revenues and royalties payable	2,582	8,343	
Accrued liabilities and other	(4,723)	(3,102)	
Net cash provided by operating activities	42,523	153,487	
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(76,842)	(134,125)	
Sale of property and equipment	(272)	30,624	
Net cash used in investing activities	(77,114)	(103,501)	
CASH FLOWS FROM FINANCING ACTIVITIES:			
Redeemable preferred stock	66,850	--	
Proceeds from long-term debt	165,000	--	
Reductions in long-term debt	(196,250)	(40,000)	
Proceeds - Notes payable	1,592	28,018	
Reductions - Notes payable	(1,524)	(2,638)	
Repurchase of stock	--	(114,000)	
Issuance of stock/exercise of stock options	307	1,740	
Preferred dividends	(1,102)	(3,129)	
Additions to deferred loan costs	(7,335)	(759)	
Net cash provided by (used in) financing activities	27,538	(130,768)	
NET CHANGE IN CASH AND CASH EQUIVALENTS	(7,053)	(80,782)	
Cash and cash equivalents at beginning of year	14,340	95,122	
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 7,287	$ 14,340	$

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2000, 2001 AND 2002 (in thousands)

	Preferred Stock		Common Stock		Additio Paid-I Capita
	Shares	Par Value	Shares	Par Value	
Balance, December 31, 1999	3,983	$ 135,000	46,410	$ 472	$ 274,
Issuance of rights to common stock	--	--	--	4	1,
Company's 401(k) plan contribution	--	--	58	1	
Issuance of shares as compensation	--	--	256	3	
Exercise of stock options	--	--	18	--	
Compensation expense	--	--	--	--	
Shares issued to SLOPI	--	--	1,000	10	
Issuance of shares from stock offering	--	--	6,021	60	38,
Preferred dividends	--	--	--	--	
Net earnings	--	--	--	--	
Balance, December 31, 2000	3,983	135,000	53,763	550	315,
Repurchase of stock	(3,983)	(135,000)	(6,000)	--	69,
Issuance of rights to common stock	--	--	--	2	1,
Company's 401(k) plan contribution	--	--	79	--	(
Issuance of shares as compensation	--	--	4	--	
Exercise of stock options	--	--	128	1	
Compensation expense	--	--	--	--	
Issuance of stock grants	--	--	--	--	6,
Preferred dividends	--	--	--	--	
Net earnings	--	--	--	--	
Balance, December 31, 2001	--	--	47,974	553	393,
Issuance of rights to common stock	--	--	--	4	1,
Company's 401(k) plan contribution	--	--	172	--	(1,
Issuance of shares as compensation	--	--	1,941	--	(15,
Fractional share adjustments	--	--	2	--	
Compensation expense	--	--	--	--	
Accum. Other Compr. Loss, net of taxes of $2,560	--	--	--	--	
Preferred dividends	--	--	--	--	
Net earnings	--	--	--	--	
Balance, December 31, 2002	--	$ --	50,089	$ 557	$ 378,

	Accumulated Other Comprehensive Loss	Treasury Stock		
		Shares	Cost	Total

Balance, December 31, 1999	$ (185)	--	$ --	$ 163,860
Issuance of rights to common stock	--	--	--	--
Company's 401(k) plan contribution	--	--	--	336
Issuance of shares as compensation	--	--	--	784
Exercise of stock options	--	--	--	70
Compensation expense	--	--	--	1,609
Shares issued to SLOPI	--	--	--	--
Issuance of shares from stock offering	--	--	--	38,593
Preferred dividends	--	--	--	(5,400
Net earnings	--	--	--	70,470
Balance, December 31, 2000	(185)	--	--	270,322
Repurchase of stock	--	6,000	(48,180)	(114,000
Issuance of rights to common stock	--	--	--	--
Company's 401(k) plan contribution	--	(79)	629	354
Issuance of shares as compensation	--	--	--	34
Exercise of stock options	--	(29)	236	554
Compensation expense	--	--	--	1,651
Issuance of stock grants	--	--	--	6,755
Preferred dividends	--	--	--	(429
Net earnings	--	--	--	22,980
Balance, December 31, 2001	(185)	5,892	(47,315)	188,221
Issuance of rights to common stock	--	--	--	--
Company's 401(k) plan contribution	--	(172)	1,382	307
Issuance of shares as compensation	--	(1,941)	15,586	--
Fractional share adjustments	--	--	--	--
Compensation expense	--	--	--	1,630
Accum. Other Compr. Loss, net of taxes of $2,560	(4,753)	--	--	(4,753
Preferred dividends	--	--	--	(3,943
Net earnings	--	--	--	(48,069
Balance, December 31, 2002	$ (4,938)	3,779	$(30,347)	$ 133,393

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

The Meridian Resource Corporation and its subsidiaries, (the "Company" or "Meridian") explores for, acquires, develops and produces oil and natural gas reserves, principally located onshore in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico. The Company was initially organized in 1985 as a master limited partnership and operated as such until 1990 when it converted into a corporation through a merger with a limited partnership of which the Company was the sole limited and general partner.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after eliminating all significant intercompany transactions.

PROPERTY AND EQUIPMENT

The Company follows the full cost method of accounting for its investments in oil and natural gas properties. All costs incurred with the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. Included in capitalized costs are general and administrative costs that are directly related with acquisition, exploration and development activities. Proceeds from the sale of oil and natural gas properties are credited to the full cost pool, unless the sale involves a significant quantity of reserves, in which case a gain or loss is recognized. Under the rules of the Securities and Exchange Commission ("SEC") for the full cost method of accounting, the net carrying value of oil and natural gas properties is limited to the sum of the present value (10% discount rate) of the estimated future net cash flows from proved reserves, based on the current prices and costs, plus the lower of cost or estimated fair market value of unproved properties.

Capitalized costs of proved oil and natural gas properties are depleted on a unit of production method using proved oil and natural gas reserves. Costs depleted include net capitalized costs subject to depletion and estimated future dismantlement, restoration, and abandonment costs. Estimated future abandonment, dismantlement and site restoration costs include costs to dismantle, relocate and dispose of the Company's offshore production platforms, gathering systems, wells and related structures, considering related salvage values.

Equipment, which includes computer equipment, hardware and software, furniture and fixtures, leasehold improvements and automobiles, is recorded at cost and is generally depreciated on a straight-line basis over the estimated useful lives of the assets, which range in periods of three to seven years.

Repairs and maintenance are charged to expense as incurred.

CASH AND CASH EQUIVALENTS

For purposes of the statements of cash flows, cash equivalents include time deposits, certificates of deposit and all highly liquid instruments with original maturities of three months or less. The Company made cash payments for interest of $11.7 million, $21.5 million and $25.3 million in 2002, 2001 and 2000, respectively. Cash payments for income taxes (federal and state, net of receipts) were none for 2002, $2.27 million for 2001, and none for 2000.

CONCENTRATIONS OF CREDIT RISK

Substantially all of the Company's receivables are due from oil and natural gas purchasers and other oil and natural gas producing companies located in the United States. Accounts receivable are generally not collateralized. Historically, credit losses incurred on receivables of the Company have not been significant.

REVENUE RECOGNITION

Meridian recognizes oil and natural gas revenue from its interests in producing wells as oil and natural gas is produced and sold from those wells (the sales method). Oil and natural gas sold is not significantly different from the Company's share of production.

EARNINGS PER SHARE

Basic earnings per share amounts are calculated based on the weighted average number of shares of Common Stock outstanding during each period. Diluted earnings per share is based on the weighted average number of shares of Common Stock outstanding for the periods, including the dilutive effects of stock options, warrants granted and convertible debt. Dilutive options and warrants that are issued during a period or that expire or are canceled during a period are reflected in the computations for the time they were outstanding during the periods being reported. Options where the exercise price of the options exceeds the average price for the period are considered antidilutive, and therefore are not included in the calculation of dilutive shares.

STOCK OPTIONS

As permitted by SFAS No. 123, "Accounting for Stock Based Compensation," the Company will continue to follow the existing accounting requirements for stock options and stock-based awards contained in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations and consensus of the Emerging Issues Task Force in terms of measuring compensation expense.

If compensation expense for these plans had been determined based on the fair value of the options consistent with SFAS No. 123, our net earnings (loss) and earnings (loss) per share would have been adjusted to the following pro forma amounts (thousands of dollars, except per share):

FAIR VALUE OF FINANCIAL INSTRUMENTS

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings and subordinated notes. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2002 and 2001, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair values of our subordinated notes due 2005 were $18.9 million and $20.0 million at December 31, 2002 and 2001, respectively. The carrying value of our subordinated notes was $20 million at December 31, 2002 and 2001.

	2002
Net earnings (loss) as reported	$(52,012)
Stock-based compensation expense determined under fair value method for all awards, net of tax	39
Net earnings (loss) pro forma	(52,051)
Basic earnings (loss) per share:	

As reported	$ (1.05)
Pro forma	$ (1.05)

Diluted earnings (loss) per share:

As reported	$ (1.05)
Pro forma	$ (1.05)

Pro forma information is required by SFAS No. 123 to reflect the estimated effect on net earnings and net earnings per share as if the Company had accounted for the stock options and other awards granted using the fair value method described in that Statement. The fair value was estimated at the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 2.54%, 4.7% and 4.8%; dividend yield of 0%; volatility factors of the expected market price of the Company's Common Stock of 0.81, 0.82 and 0.84 for 2002, 2001 and 2000, respectively; and a weighted-average expected life of five years. These assumptions resulted in a weighted average grant date fair value of $1.97, $4.08 and $2.73 for options granted in 2002, 2001 and 2000, respectively. For purposes of the pro forma disclosures, the estimated fair value is amortized to expense over the awards' vesting period.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options. Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years.

DERIVATIVE FINANCIAL INSTRUMENTS

In June 1998 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Certain Hedging Activities. In June 2000 the FASB issued SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activity, an Amendment of SFAS 133. SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. SFAS No. 133 and SFAS No. 138 are effective for all fiscal quarters of all fiscal years beginning after June 30, 2000; the Company adopted SFAS No. 133 and SFAS No. 138 on January 1, 2001.

The Company enters into swaps, options, collars and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. The Company's derivative financial instruments have not been entered into for trading purposes and the Company has the ability and intent to hold these instruments to maturity. Counterparties to the Company's interest rate swap agreements are major financial institutions.

All derivatives are recognized on the balance sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as either a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment ("fair value" hedge) or a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability ("cash flow" hedge) The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as fair-value or cash-flow hedges to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a cash-flow hedge are recorded in other comprehensive income, until earnings are affected by the variability in cash flows of the designated hedged item. The Company reflected no gain or loss related to hedge ineffectiveness during the each of the two years ended December 31, 2002.

The Company discontinues hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised, the derivative is redesignated as a hedging instrument because it is unlikely that a forecasted transaction will occur, or management determines that designation of the derivative as a hedging instrument is no longer appropriate.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the Company continues to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, the Company continues to carry the derivative at its fair value on the balance sheet and recognizes any subsequent changes in its fair value in earnings. Gains or losses accumulated in other comprehensive income at the time the hedge relationship is terminated are recorded in earnings over the original life of the derivative instrument.

EARLY ADOPTION OF FAS NO. 145

On July 1, 2002, we adopted the provisions of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" ("SFAS No. 145"). The applicable portion of this Statement rescinds Statement of Financial Accounting Standards No. 4 "Reporting Gains and Losses from Extinguishment of Debt" which required all gains and losses from extinguishment of debt to be aggregated and, when material, classified as an extraordinary item, net of related income tax effect. Consistent with SFAS No. 145, the $1.2 million in unamortized debt costs associated with the termination of the Company's revolving credit agreement in August 2002 were recognized as credit facility retirement costs in the Consolidated Statement of Operations. SFAS No. 145 also amends Statement of Financial Accounting Standards No. 13 "Accounting for Leases" ("SFAS No. 13") to require that certain lease modifications having economic effects similar to sale-leaseback transactions be accounted for in the same manner as sale-leaseback transactions. This portion of SFAS No. 145 did not have any effect on our financial position or results of operations for any periods presented.

NEW ACCOUNTING PRONOUNCEMENT

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143 "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. This standard will require us to record a liability for the fair value of our dismantlement an abandonment costs, excluding salvage values. The standard is effective for fiscal years beginning after June 15, 2002. The Company has completed its assessment of SFAS No. 143. At January 1, 2003, we estimated the impact of SFAS No. 143 and expect to record an after tax loss of between $0.5 million and $2.5 million as a cumulative effect of change in accounting principle. Additionally, the Company expects to record an asset retirement obligation liability of between $4.0 million and $5.0 million and an increase to net properties and equipment of between $2.5 million and $3.5 million. The application of SFAS No. 143 in 2003 and future years will result in the recognition of accretion expense related to the discounted liability for the asset retirement obligation and should not have a material impact on the Company's depletion rate. There will be no impact on the Company's cash flow as a result of adopting SFAS No. 143. This cumulative effect of change in accounting principle will be a non-cash charge to net income in the first quarter of 2003.

USE OF ESTIMATES

The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities, if any, at the date of the financial statements. The Company analyzes its estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes and contingencies and litigation. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

RECLASSIFICATION OF PRIOR PERIOD STATEMENTS

Certain minor reclassifications have been made to the prior period financial statements to conform to current year presentation.

3. IMPAIRMENT OF LONG-LIVED ASSETS

In the third quarter 2002, a negative revision in oil and natural gas proved undeveloped reserves associated with an unsuccessful well drilled in Kent Bayou Field resulted in a full cost ceiling write-down totaling $69.1 million ($46.9 million after tax) of its oil and natural gas properties.

A decline in oil and natural gas prices during 2001 resulted in the Company recognizing full cost ceiling write-downs totaling $6.6 million of its oil and natural gas properties.

Due to the potential volatility in oil and gas prices and their effect on the carrying value of the Company's proved oil and gas reserves, there can be no assurance that future write-downs will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas reserves and the carrying value of oil and natural gas properties, including volatile oil and natural gas prices, downward revisions in estimated proved oil and natural gas reserve quantities and unsuccessful drilling activities.

4. DEBT

REVOLVING CREDIT AGREEMENT

During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a new three-year $175 million underwritten senior secured credit agreement (the "Credit Agreement") with Societe Generale, as administrative agent, lead arranger and book runner, and Fortis Capital Corp., as co-lead arranger and documentation agent. The remaining unamortized deferred debt costs associated with the prior credit facility of $1.2 million were written off in September 2002. The current borrowing base under the existing Credit Agreement was established on September 23, 2002, at $165 million, with the borrowing base redetermination date scheduled for November 30,2002. The parties to the Credit Agreement have entered into an amendment of the Agreement, effective March 31, 2003, to eliminate the November 30, 2002, redetermination date and to reschedule the borrowing base redetermination date for April 30, 2003, and quarterly redetermination thereafter. The current borrowing base is $165 million, which is the same as that established upon the signing of the original Credit Agreement.

On March 31, 2003, the Company received notice from its senior lenders that effective April 30, 2003 the borrowing base will be established at $138.5 million. Accordingly, the Company will reflect the difference of $26.5 million as a current maturity of its long-term debt and will be required to make up the deficiency through the addition of reserves or value to its current reserve base or pay the senior lenders this deficiency within 90 days of the effective date of April 30, 2003. Though no assurances can be made that sufficient funds will be available to pay this deficiency, management believes that it can satisfy this deficiency through a combination of the addition of reserves, third-party financing, property sales and cash flow.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders under the Credit Agreement have the right to redetermine the borrowing base at any time once during each calendar year and the Company has the right to obtain a redetermination by the banks of the borrowing base once during each calendar year. Borrowings under the Credit Agreement are secured by pledges of outstanding capital stock of the Company's subsidiaries and a mortgage on the Company's oil and natural gas properties of at least 90% of its present value of proved properties. The Credit Agreement contains various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock. The Company has received from the senior lenders a waiver of the covenant that would have triggered an event of default as a result of the independent auditors' report which contained a "going concern" modification for our 2002 consolidated financial statements. Borrowings under the Credit Agreement mature on August 13, 2005.

Under the new Credit Agreement, the Company may secure either (i) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate plus an additional 0.5% to 1.5% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base; or a federal funds-based rate plus 1/2 of 1% or (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate ("LIBOR") plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Credit Agreement also provides for commitment fees ranging from 0.375% to 0.5% per annum.

SUBORDINATED CREDIT AGREEMENT

The Company extended and amended a short-term subordinated credit agreement with Fortis Capital Corporation for $25 million on April 5, 2002, with a maturity date of December 31, 2004. The notes are unsecured and contain customary events of default, but do not contain any maintenance or other restrictive covenants. The interest rate is the London interbank offered rate ("LIBOR") plus 4.5% through December 31, 2002, LIBOR plus 5.5% from January 1, 2003, through August 31, 2003, and LIBOR plus 6.5% from September 1, 2003, through December 31, 2004. Note payments of $5 million each are due on August 31, 2003 and April 30, 2004, with the remaining $5 million payable on December 31, 2004. Note payments totaling $6.25 million were paid in 2002, with an additional $1.25 million being paid in January 2003. An

additional $2.5 million that is currently due has been deferred in conjunction with the March 31, 2003, amendment to the Credit Agreement. No amounts are payable under this subordinated debt until any and all borrowing base deficiencies under the Credit Agreement are satisfied. The Company is in compliance under this agreement.

9 1/2% CONVERTIBLE SUBORDINATED NOTES

During June 1999, the Company completed private placements of an aggregate of $20 million of its 9 1/2% Convertible Subordinated Notes due June 18, 2005 (the "Notes"). The Notes are unsecured and contain customary events of default, but do not contain any maintenance or other restrictive covenants. Interest is payable on a quarterly basis. The Company is in compliance under this agreement.

During March 2002, the Company and the holders of the Notes amended the conversion price from $7.00 to $5.00 per share. The Notes are convertible at any time by the holders of the Notes into shares of the Company's Common Stock, $0.01 par value, utilizing the conversion price. The conversion price is subject to customary anti-dilution provisions. The holders of the Notes have been granted registration rights with respect to the shares of Common Stock that would be issued upon conversion of the Notes.

Scheduled maturities for the next five years and thereafter, as of December 31, 2002, are as follows: $35.25 million in 2003, $10.0 million in 2004, $158.5 million in 2005, and none thereafter.

5. CAPITAL RESOURCES AND LIQUIDITY

As noted in our discussion of the Credit Facility, there will be a $26.5 million borrowing base deficiency at April 30, 2003 that must be satisfied by either sufficient additions to our proved reserves or repayment on or before July 29, 2003 to avoid an event of default. An event of default which is not cured results in the entire debt outstanding becoming due and payable, unless it is waived by the senior lenders or the Credit Agreement is otherwise amended. Also, repayment of $2.5 million, after our $1.25 million January 2003 payment, under our subordinated debt agreement is due but is deferred pending satisfaction of the borrowing base deficiency under the amended Credit Agreement. The $5 million subordinated debt repayment that will become due in August 2003 is also subject to deferral for any borrowing base deficiencies that may exist at that time. The $34 million due in 2003 under these agreements represents a significant component of our $47.1 million working capital deficiency at December 31, 2002.

Based upon our expected level of production and considering a reduced level of capital spending plan of $15 to $20 million, we project that our available cash flow from operations is not expected to be sufficient to fund the April 30, 2003 borrowing base deficiency and amounts due or to become due in 2003 under our subordinated debt agreement. In order to address this liquidity issue and address the broader issue of aligning our capital structure with our long-term business strategy, the following plans to sell non-strategic oil and gas properties and secure new sources of capital through subordinated debt or similar financing arrangements have been initiated.

In an effort to address the liquidity issue and the broader issue of aligning our capital structure with our long-term business strategy, the Company is pursuing several plans that it believes will remedy the current borrowing base deficiency of $26.5 million.

First, it should be noted that, as of December 31, 2002, the Company's proved developed reserves have a present value based on SEC regulations that include prices in effect at year-end and a 10% discount rate, of approximately $460 million or approximately three (3) times its total senior credit facility.

Based on current cash flow projections and the Company's specific knowledge of its drilling prospects and historical performance in the areas of anticipated activity, potential opportunities for non-strategic property sales and/or third party capital funding, it is management's judgment and belief that its business plan will provide the Company with the means to meet the required coverage for the new borrowing base by a combination of newly discovered reserves, proceeds from strategic sales of non-essential properties, where appropriate, and/or the infusion of third party capital in the form of sub-debt, all on or before July 31, 2003.

Currently, the Company has scheduled two (2) exploration and development wells that can be drilled and logged prior to July 31, 2003, barring mechanical or other issues out of the Company's control, such as permitting issues, weather or equipment availability. The Company believes that these wells together have the potential of adding reserves sufficient to remedy the borrowing base deficiency.

In addition, the Company has identified certain properties which are not essential to its future growth and which it is in the process of marketing on a limited basis. These include reserves of up to 100 BCFE and production of approximately 50 mmcfe/d having an SEC PV10 value of over $281 million. It is believed that a sale price of all or a sufficient portion of these properties can be achieved on or before July 31, 2003.

Further, the Company is in discussions with third parties regarding the infusion of capital of up to $45-50 million in the form of sub-debt capital. These discussions are subject to certain due diligence verification of the reserves, financial reported data and title examination as well as approval by the senior lenders. The proceeds will be used to reduce the current indebtedness of the senior credit facility as well as capital expenditures for calendar year 2003. It is anticipated that the due diligence can be concluded on or before April 30, 2003. Assuming positive results on both the due diligence and of the terms and conditions of the sub-debt facility by the senior lenders, it is anticipated that this transaction could close on or before July 31, 2003.

Although there can be no assurances, management is confident that sufficient proceeds from the sale of non-strategic oil and natural gas properties and new subordinated debt or similar financing arrangements will be generated in sufficient time to satisfy our funding obligations under both the Credit Agreement and the subordinated debt agreement to permit an orderly reduction and restructuring of our debt capital.

6. LEASE OBLIGATIONS

The Company has a seven-year operating lease for office space with a primary term expiring in September 2006. The Company also has operating leases for equipment with various terms, none exceeding three years. Rental expense amounted to approximately $2.2 million, $2.1 million and $1.9 million in 2002, 2001 and 2000, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $1.6 million for each of the years 2003 - 2005, $1.2 million for the year 2006, and none thereafter.

7. COMMITMENTS AND CONTINGENCIES

LITIGATION

On October 29, 2002, Veritas DGC Land Inc. ("Veritas Land") filed a complaint against Meridian. The dispute concerns a contract for seismic services for Meridian's Biloxi Marsh project in St. Bernard Parish, Louisiana. Purporting to invoke force majeure, Veritas Land, together with Veritas DGC Inc. (collectively, "Veritas"), unilaterally terminated the parties' contract. The main dispute is whether Veritas had breached the parties' contract before the alleged force majeure events and/or when it terminated the contract; Meridian has not made any payments to Veritas under the parties' contract. Veritas' complaint seeks breach-of-contract damages of approximately $6.8 million together with interest, costs and attorneys' fees.

On December 23, 2002, Meridian filed an answer denying the relief sought by Veritas and asserting a counterclaim against Veritas (1) declaring that (i) Meridian is not in breach of the parties' seismic contract, (ii) Meridian owes no amounts to Veritas under the parties' seismic contract or otherwise, (iii) Veritas materially breached the parties' contract, and (iv) Veritas Land is solidarily liable to Meridian for all liability of Veritas DGC Inc., and (2) seeking an award to Meridian of all attorneys' fees, court costs and other expenses, amounts and damages incurred or suffered (or to be incurred or suffered) by Meridian. On January 27, 2003, Veritas Land filed an answer to Meridian's counterclaim, generally denying the counterclaim and asserting various affirmative defenses thereto. Veritas DGC Inc. has not yet answered the counterclaim.

No scheduling order has yet been issued. The parties have not yet issued discovery to each other. Meridian intends to vigorously defend the claims against it and to vigorously prosecute its counterclaim.

There are no other material legal proceedings to which Meridian or any of its subsidiaries or partnerships is a party or to which any of its property is subject, other than ordinary and routine litigation incidental to the business of producing and exploring for crude oil and natural gas.

8. TAXES ON INCOME

Provisions (benefits) for federal and state income taxes are as follows (thousands of dollars):

YEAR ENDED DECEMBER 31,

	2002	2001	2000
Current:			
Federal	$ 327	$ 77	$ 779
State	(29)	(377)	1,121
Deferred:			
Federal	(22,300)	13,800	8,500
	$ (22,002)	$ 13,500	$ 10,400

Income tax expense as reported is reconciled to the federal statutory rate (35%) as follows (thousands of dollars):

	YEAR ENDED DECEMBE	
	2002	2001
Income tax provision (benefit) computed at statutory rate	$ (24,525)	$ 12,768
Nondeductible costs	308	977
State income tax net of federal tax benefit	(19)	(245)
Net operating loss carryforwards not benefited in the income tax provision	--	--
Change in valuation allowance	2,234	--
	$ (22,002)	$ 13,500

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Deferred income taxes reflect the net tax effects of net operating losses, depletion carryovers, and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax assets and liabilities are as follows (thousands of dollars):

	DEC
	2002
Deferred tax assets:	
Net operating tax loss carryforward	$ 54,521
Statutory depletion carryforward	950
Tax credits	1,651
Unrealized hedge loss	2,560
Other	4,110
Valuation allowance	(2,734
Total deferred tax assets	61,058

Deferred tax liabilities:	
Book in excess of tax basis in oil and gas properties	58,428
Basis differential in long-term investments	70
Total deferred tax liabilities	58,498
Net deferred tax (liability)	$ 2,560

As of December 31, 2002, the Company has approximately $155.8 million of tax net operating loss carryforwards which begin to expire in 2004. The net operating loss carryforwards assume that certain items, primarily intangible drilling costs, have been deducted to the maximum extent allowed under the tax laws for the current year. However, the Company has not made a final determination if an election will be made to capitalize all or part of these items for tax purposes. A significant portion of the net operating loss carryforwards are subject to change in ownership and separate return limitations that could restrict the Company's ability to utilize such losses in the future. Appropriate accounting policy requires a valuation allowance to be recognized if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. Accordingly, the Company has recorded a valuation allowance against a portion of its net operating loss carryforward, the realization of which is not reasonably assured. The net deferred tax asset relates to the tax effects associated with the deferred hedge loss from commodity price risk management activities reflected as a component of other comprehensive income (loss).

9. 8.5% REDEEMABLE CONVERTIBLE PREFERRED STOCK

A private placement of $66.85 million of 8.5% redeemable convertible preferred stock was completed during May 2002. The preferred stock is convertible into shares of the Company's Common Stock at a conversion price of $4.75 per share. Dividends are payable semi-annually in cash or additional preferred stock. At the option of the Company, one-third of the preferred shares can be forced to convert to Common Stock if the closing price of the Company's Common Stock exceeds 150% of the conversion price for 30 out of 40 consecutive trading days on the New York Stock Exchange. Based on the above conversion criteria, the Company can elect to convert up to one-third of the original issue provided that the conversion occurs no sooner than twelve months from the most recent conversion. The preferred stock is subject to redemption at the option of the Company after March 2005, and mandatory redemption on March 31, 2009. The holders of the preferred stock have been granted registration rights with respect to the shares of Common Stock issued upon conversion of the preferred stock. Dividends of $3.9 million were accumulated during 2002, of which $1.1 million was paid in cash and $2.84 million was satisfied with the issuance of additional shares of redeemable preferred stock.

10. STOCKHOLDERS' EQUITY

COMMON STOCK

On September 29, 2000, the Company announced that it sold to certain investors an aggregate of 6,021,500 shares of Common Stock at a price of $6 5/8 per share under the terms of the prospectus supplement dated September 28, 2000. The shares were placed with certain investors on a best-efforts basis. In connection with the placement of the shares, the Company paid the placement agents a total fee of approximately $1.2 million, resulting in proceeds of approximately $38.7 million to the Company. The Company used the proceeds from this sale to fund in part the exercise of the option to repurchase Preferred and Common Stock from Shell for $114 million on January 29, 2001.

PREFERRED STOCK

On June 30, 1998, the Company issued to SLOPI 3,982,906 shares of the Company's Preferred Stock. The Preferred Stock had an aggregate stated value of $135 million and ranked prior to the Common Stock as to distribution of assets and payment of dividends. The holder thereof had the right to convert the Preferred Stock into an aggregate of 12,837,428 shares of Common Stock. The Preferred Stock was entitled to receive, when and as declared by the Board of Directors, a cash dividend at the rate of 4% per annum on the stated value per share. On January 29, 2001, the Company completed the repurchase of all of the then outstanding Preferred Stock. See following notes below.

Meridian and SLOPI, on July 18, 2000, announced a definitive agreement granting Meridian an option to repurchase all of the outstanding shares of Meridian Preferred Stock (convertible into 12.8 million shares of Common Stock), plus six million shares of Meridian Common Stock then held by Shell, for an aggregate cash price of $114 million. The "Option and Standstill Agreement" was exercisable in a single transaction through January 31, 2001. As consideration for the grant of the option, Meridian issued Shell one million shares of Meridian Common Stock in July 2000.

On January 29, 2001, the Company completed the repurchase of all of the then outstanding Preferred Stock (convertible into 12.8 million shares of Common Stock) and six million shares of Common Stock from Shell for $114 million. The $114 million stock buyback price was generated through a balanced financing structure including $38.7 million in net proceeds from the issuance of Common Stock at $6 5/8 per share; $25 million in subordinated debt; and $50.3 million of available cash flow and proceeds from the sale of non-core properties. Shell remains Meridian's largest shareholder, with approximately 7.1 million shares of Common Stock.

WARRANTS

The Company had the following warrants outstanding at December 31, 2002:

WARRANTS	NUMBER OF SHARES	EXERCISE PRICE	EXPIRATION DATE
Executive Officers	1,428,000	$ 5.85	*
General Partner	1,014,504	$ 0.19	December 31, 2015

* A date one year following the date on which the respective officer ceases to be an employee of the Company.

On June 7, 1994, the shareholders of the Company approved a conversion of Class "B" Warrants held by Joseph A. Reeves, Jr. and Michael J. Mayell, which entitled each of them to purchase an aggregate of 714,000 shares of common stock, to

Executive Officer Warrants. The Warrants expire one year following the date on which the respective officer ceases to be an employee of the Company. The Warrants further provide that in the event the officer's employment with the Company is terminated by the Company without "cause" or by the officer for "good reason," the officer will have the option to require the Company to purchase some or all of the Warrants held by the officer for an amount per Warrant equal to the difference between the exercise price, $5.85 per share, and the then prevailing market price of the common stock. The Company may satisfy this obligation with shares of common stock.

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STOCK OPTIONS

Options to purchase the Company's Common Stock have been granted to officers, employees, nonemployee directors and certain key individuals, under various stock option plans. Options generally become exercisable in 25% cumulative annual increments beginning with the date of grant and expire at the end of ten years. At December 31, 2002, 2001 and 2000, 445,765, 642,897 and 915,997 shares, respectively, were available for grant under the plans. A summary of option transactions follows:

	NUMBER OF SHARES
Outstanding at December 31, 1999	4,678,433
Granted	183,945
Exercised	(17,750)
Canceled	(454,233)
Outstanding at December 31, 2000	4,390,395
Granted	73,500
Exercised	(128,320)
Canceled	(176,000)
Outstanding at December 31, 2001	4,159,575
Granted	15,000
Exercised	--
Canceled	(10,500)
Outstanding at December 31, 2002	4,164,075
Shares exercisable:	
December 31, 2002	4,089,450
December 31, 2001	4,051,075
December 31, 2000	3,527,941

	OPTIONS OUTSTANDING		OPTIONS EXERCISABL	
RANGE OF EXERCISABLE PRICES	OUTSTANDING AT DECEMBER 31, 2002	WEIGHTED AVERAGE EXERCISE PRICE	EXERCISABLE AT DECEMBER 31, 2002	W A EXER

$2.44 - $4.94	3,374,925	$ 3.43	3,356,550	$
$5.31 - $9.00	495,500	8.15	439,250	
$10.38 - $13.25	293,650	11.35	293,650	
	4,164,075	$ 4.55	4,089,450	$

The weighted average remaining contractual life of options outstanding at December 31, 2002, was approximately seven years.

DEFERRED COMPENSATION

In July 1996, the Company through the Compensation Committee of the board of Directors offered to Messrs. Reeves and Mayell (the Company's Chief Executive Officer and President, respectively) the option to accept in lieu of cash compensation for their respective base salaries Common Stock pursuant to the Company's Long Term Incentive Plan. Under such grants, Messrs. Reeves and Mayell each elected to defer $400,000 for 2000, $417,000 for 2001 and $415,000 for 2002, which is substantially all of their salaried compensation for each of the years. In exchange for and in consideration of their accepting this option to reduce the Company's cash payments to each of Messrs. Reeves and Mayell, the company granted to each officer a matching deferral equal to 100% of that amount deferred, which is subject to a one-year vesting period. Under the terms of the grants, the employee and matching deferrals are allocated to a Common Stock account in which units are credited to the accounts of the officer based on the number of shares that could be purchased at the market price of the Common Stock at December 31, 1996, for deferrals in 1997, at December 31, 1997, for deferrals during the first half of 1998, at June 30, 1998, for deferrals during the second half of 1998, at December 31, 1998, for deferrals during the first half of 1999, at June 30, 1999, for deferrals during the second half of 1999, at December 31, 1999, for deferrals during the first half of 2000, at June 30, 2000, for deferrals during the second half of 2000, at December 31, 2000, for deferrals during the first half of 2001, at June 30, 2001, for deferrals during the second half of 2001, at December 31, 2001, for deferrals during the first half of 2002, and at June 30, 2002, for deferrals during the second half of 2002. At December 31, 2002, the plan had reserved 3,600,000 shares of Common Stock for future issuance and 1,427,804 rights have been granted. No actual shares of Common Stock have been issued and the officer has no rights with respect to any shares unless and until there is a distribution. Distributions are to be made upon the death, retirement or termination of employment of the officer.

The obligations of the Company with respect to the deferrals are unsecured obligations. The shares of common stock that may be issuable upon distribution of deferrals have been treated as a common stock equivalent in the financial statements of the Company. Although no cash has been paid, to either Mr. Reeves or Mr. Mayell for their base salaries during these periods, the compensation expense required to be reported by the Company for the equity grants was $1,630,000, $1,651,000 and $1,609,000 for 2002, 2001 and 2000 periods, respectively, and is reflected in general and administrative expense for the years ended December 31, 2002, 2001 and 2000, respectively.

STOCKHOLDER RIGHTS PLAN

On May 5, 1999, the Company's Board of Directors declared a dividend distribution of one Right for each then-current and future outstanding share of

Common Stock. Each Right entitles the registered holder to purchase one one-thousandth interest in a share of the Company's Series B Preferred Stock with a par value of $.01 per share and an exercise price of $30. Unless earlier redeemed by the Company at a price of $.01 each, the Rights become exercisable only in certain circumstances constituting a potential change in control of the Company and will expire on May 5, 2009.

Each share of Series B Junior Participating Preferred Stock purchased upon exercise of the Rights will be entitled to certain minimum preferential quarterly dividend payments as well as a specified minimum preferential liquidation payment in the event of a merger, consolidation or other similar transaction. Each share will also be entitled to 100 votes to be voted together with the Common stockholders and will be junior to any other series of Preferred Stock authorized or issued by the Company, unless the terms of such other series provides otherwise.

In the event of a potential change in control, each holder of a Right, other than Rights beneficially owned by the acquiring party (which will have become void), will have the right to receive upon exercise of a Right that number of shares of Common Stock of the Company, or, in certain instances, Common Stock of the acquiring party, having a market value equal to two times the current exercise price of the Right.

11. PROFIT SHARING AND SAVINGS PLAN

The Company has a 401(k) profit sharing and savings plan (the "Plan") that covers substantially all employees and entitles them to contribute up to 15% of their annual compensation, subject to maximum limitations imposed by the Internal Revenue Code. The Company matches 100% of each employee's contribution up to 6.5% of annual compensation subject to certain limitations as outlined in the Plan. In addition, the Company may make discretionary contributions which are allocable to participants in accordance with the Plan. Total expense related to the to Company's 401(k) plan was $306,000, $292,000, and $361,000 in 2002, 2001, and 2000, respectively.

During 1998, the Company implemented a net profits program that was adopted effective as of November 1997. All employees participate in this program. Pursuant to this program, the Company adopted three separate well bonus plans: (i) The Meridian Resource Corporation Geoscientist Well Bonus Plan (the "Geoscientist Plan"); (ii) The Meridian Resource Corporation TMR Employees Trust Well Bonus Plan (the "Trust Plan") and (iii) The Meridian Resource Corporation Management Well Bonus Plan (the "Management Plan" and with the Management Plan and the Geoscientist Plan, the "Well Bonus Plans"). Payments under the plans are calculated based on revenues from production on previously discovered reserves, as realized by the Company at current commodity prices, less operating expenses. Total compensation related to these plans totaled $4.2 million, $7.1 million and $12.0 million in 2002, 2001 and 2000, respectively. A portion of these amounts has been capitalized with regard to personnel engaged in activities associated with exploratory projects. The Executive Committee of the Board of Directors, which is comprised of Messrs. Reeves and Mayell, administers each of the Well Bonus Plans. The participants in each of the Well Bonus Plans are designated by the Executive Committee in its sole discretion. Participants in the Management Plan are limited to executive officers of the Company and other key management personnel designated by the Executive Committee. Neither Messrs. Reeves or Mayell will participate in the Management Plan. The participants in the Trust Plan generally will be all employees of the Company that do not participate in one of the other Well Bonus Plans. Effective March 2001, the participants in the Geoscientist Plan were notified that no additional future wells would be placed into the plan. During 2002, the Executive Committee decided to modify this position and for certain key geoscientists the plan will include future new wells. Additionally, certain interests in the Well Bonus Plans were repurchased and terminated from current and former employees for issuance of stock grants (see Note 11).

Pursuant to the Well Bonus Plans, the Executive Committee designates, in its sole discretion, the individuals and wells that will participate in each of the Well Bonus Plans. The Executive Committee also determines the percentage bonus that will be paid under each well and the individuals that will participate thereunder. The Well Bonus Plans cover all properties on which the Company expends funds during each participant's employment with the Company, with the percentage bonus generally ranging from less than .1% to .5%, depending on the level of the employee. It is intended that these well bonuses function similar to an actual net profit interests, except that the employee will not have a real property interest and his or her rights to such bonuses will be subject to a one-year vesting period, except for grants in 1998 for which all employees were deemed vested, and will be subject to the general credit of the Company. Payments under vested bonus rights will continue to be made after an employee leaves the employment of the Company based on their adherence to the obligations required in their non-compete agreement upon termination. The Company has the option to make payments in whole, or in part, utilizing shares of Common Stock. The determination whether to pay cash or issue Common Stock will be based upon a variety of factors, including the Company's current liquidity position and the fair market value of the Common Stock at the time of issuance.

In connection with the execution of their employment contracts in 1994, both Messrs. Reeves and Mayell were granted a 2% net profit interest in the oil and natural gas production from the Company's properties to the extent the Company acquires a mineral interest therein. The net profits interest for Messrs. Reeves and Mayell

applies to all properties on which the Company expends funds during their employment with the Company. Each grant of a net profits interest is reflected at a value based on a third party appraisal of the interest granted. The net profit interests represent real property rights that are not subject to vesting or continued employment with the Company. Messrs. Reeves and Mayell will not participate in the Well Bonus Plans for any particular property to the extent the original net profit interest grants covers such property.

12. ISSUANCE OF STOCK GRANTS

Effective December 2001, an agreement was executed to repurchase and terminate certain interests in the Well Bonus Plans from current and former employees in exchange for the issuance of Common Stock. The offering was for a total of 1,940,991 shares of our Common Stock. The Common Stock was issued on February 4, 2002, at the last reported sales price of $3.48 per share.

13. OIL AND NATURAL GAS HEDGING ACTIVITIES

The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into swaps and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at or prior to expiration or exchanged for physical delivery contracts. The Company does not obtain collateral to support the agreements, but monitors the financial viability of counter-parties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction.

The Company's results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, the Company has entered into various swap agreements. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

The Company's results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, the Company has entered into various swap agreements. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

These swaps have been designated as cash flow hedges as provided by FAS 133 and any changes in fair value of the cash flow hedge resulting from ineffectiveness of the hedge is reported in the consolidated statement of operation as revenues.

The estimated December 31, 2002, fair value of the Company's oil and natural gas swaps is an unrealized loss of $7.3 million ($4.8 million net of tax) recognized in other comprehensive income. Based upon December 31, 2002, oil and natural gas commodity prices approximately $5.9 million of the loss deferred in other comprehensive income is expected to lower gross revenues over the next twelve months when the revenues are generated. The swap agreements expire at various dates through July 31, 2005.

Payments under these swap agreements reduced oil and natural gas revenues by $1,183,000 for the year ended December 31, 2002, as a result of hedging transactions. During the year ended December 31, 2001, the Company had no material open hedging agreements. During the year ended December 31, 2000, payments under swap agreements reduced oil and natural gas revenues by $5,419,000.

The Notional Amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 44% of our proved developed natural gas production and 70% of our proved developed oil production. The fair values of the hedges are based on the difference between the strike price and the New York Mercantile Exchange future prices for the applicable trading months.

	Notional Amount	Weighted Average Strike Price ($ per unit)	Fair Value (unrealize at December 31, 2002 (in thousands)

Natural Gas (mmbtu)			
January 2003 - June 2005	8,610,000	$ 3.80	$ 4,721
Oil (bbls)			
January 2003 - July 2005	3,320,000	$ 24.55	$ 2,592
			$ 7,313

14. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2002, 2001 and 2000, were as follows (based on purchases of oil and natural gas as a percent of total oil and natural gas sales):

	YEAR ENDED DECEMBER 31,	
CUSTOMER	2002	2001
Equiva Trading Company(1)............................	33%	30%
Louisiana Intrastate Gas.............................	17%	20%
Conoco, Inc..	12%	--
Superior Natural Gas.................................	--	13%

(1) Equiva Trading Company is an affiliate of Shell.

15. RELATED PARTY TRANSACTIONS

Historically since 1994, affiliates of Meridian have been permitted to hold interests in projects of the Company. With the approval of the Board of Directors, Texas Oil Distribution and Development, Inc. ("TODD") and Sydson Energy, Inc. ("Sydson"), entities controlled by Joseph A. Reeves, Jr. and Michael J. Mayell, respectively, have each invested in all Meridian drilling locations on a promoted basis, where applicable, at a 1.5% working interest basis. The maximum percentage that either may elect to participate in any prospect is a 4% working interest. On a collective basis, TODD and Sydson invested $3,289,000, $4,846,000 and $3,027,000 for the years ended December 31, 2002, 2001 and 2000, respectively, in oil and natural gas drilling activities for which the Company was the operator. Net amounts due from (to) TODD and Mr. Reeves were approximately $186,000 and ($202,000) as of December 31, 2002 and 2001, respectively. Net amounts due from Sydson and Mr. Mayell were approximately $1,370,000 and $1,046,000 as of December 31, 2002 and 2001, respectively.

Mr. Joe Kares, a Director of Meridian, is a partner in the public accounting firm of Kares & Cihlar, which provided the Company with accounting services for the years ended December 31, 2002, 2001 and 2000 and

received fees of approximately $282,000, $269,000 and $304,000, respectively. Such fees exceeded 5% of the gross revenues of Kares & Cihlar for those respective years. Management believes that such fees were equivalent to fees that would have been paid to similar firms providing such services in arm's length transactions.

Mr. Gary A. Messersmith, a Director of Meridian, is currently a partner in the law firm of Looper, Reed and McGraw in Houston, Texas, which provided legal services for the Company for the years ended December 31, 2002 and 2001, and received fees of approximately $27,000 and $58,000, respectively. He previously was a partner in the law firm of Fouts & Moore, L.L.P., in Houston, Texas, which provided legal services for the Company for the years ended December 31, 2001 and 2000 and received fees of approximately $66,000 and $124,000, respectively. In addition, the Company has Mr. Messersmith on a personal retainer of $8,333 per month relating to his services provided to the Company and a bonus in the form of personal property valued at $12,500 was awarded during 2002. Mr. Messersmith also participated in the Management Plan described in Note 10 above pursuant to which he was paid approximately $377,000 during 2002, $401,000 during 2001 and $383,000 and received 11,472 shares of the Company's Common Stock during 2000.

16. EARNINGS PER SHARE
(in thousands, except per share)

The following table sets forth the computation of basic and diluted earnings (loss) per share:

	YEAR ENDED DECEMBE	
	2002(1)	2001
Numerator:		
Net earnings (loss) applicable to common stockholders	$ (52,012)	$ 22,551
Plus income impact of assumed conversions:		
Preferred stock dividends	3,943	429
Interest on convertible subordinated notes	1,236	1,211
Net earnings (loss) applicable to common stockholders plus assumed conversions	$ (46,833)	$ 24,191
Denominator:		
Denominator for basic earnings per share - weighted-average shares outstanding	49,763	48,350
Effect of potentially dilutive common shares:		
Convertible preferred stock	--	985
Redeemable preferred stock	N/A	--
Convertible subordinated notes	N/A	2,857
Employee and director stock options	N/A	1,263
Warrants	N/A	2,387
Denominator for diluted earnings per share - weighted-average shares outstanding and assumed conversions	49,763	55,842
Basic earnings (loss) per share	$ (1.05)	$ 0.47
Diluted earnings (loss) per share	$ (1.05)	$ 0.43

(1) Anti-dilutive in 2002.

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17. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Results of operations by quarter for the years ended December 31, 2002 and 2001, were (thousands of dollars, except per share):

	QUARTER ENDED		
	MARCH 31	JUNE 30	SEPT. 30
2002			
Revenues	$ 23,848	$ 32,473	$ 26,775
Results of operations from exploration and production activities(1)	5,753	12,982	(65,894)
Net earnings (loss)(2)	$ (1,577)	$ 3,172	$ (51,384)
Net earnings (loss) per share:(2)			
Basic	$ (0.03)	$ 0.06	$ (1.03)
Diluted	(0.03)	0.06	(1.03)
2001			
Revenues	$ 70,069	$ 46,026	$ 33,758
Results of operations from exploration and production activities(1)	44,073	22,486	9,174
Net earnings (loss)(2)	$ 19,668	$ 7,691	$ 1,233
Net earnings (loss) per share:(2)			
Basic	$ 0.40	$ 0.16	$ 0.03
Diluted	0.34	0.15	0.03

(1) Results of operations from exploration and production activities, which approximates gross profit, are computed as operating revenues less lease operating expenses, severance and ad valorem taxes, depletion and impairment of oil and natural gas properties.

(2) Applicable to common stockholders.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION
(UNAUDITED)

The following information is being provided as supplemental information in accordance with the provisions of SFAS No. 69, "Disclosures about Oil and Gas Producing Activities."

COSTS INCURRED IN OIL AND NATURAL GAS ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES
(thousands of dollars)

		YEAR ENDED DECEM
	2002	2001
Costs incurred during the year:(1)		
Property acquisition costs		
Unproved	$ 4,757	$ 11,33
Proved	--	-
Exploration	32,293	91,90
Development	38,998	30,47
	$ 76,048	$ 133,70

(1) Costs incurred during the years ended December 31, 2002, 2001 and 2000 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $11,684,000, $13,459,000 and $14,477,000, respectively.

CAPITALIZED COSTS RELATING TO OIL AND NATURAL GAS PRODUCING ACTIVITIES
(thousands of dollars)

	DEC
	2002
Capitalized costs	$ 1,161,97
Accumulated depletion	755,43
Net capitalized costs	$ 406,54

At December 31, 2002 and 2001, unevaluated costs of $18,993,000 and $30,247,000, respectively, were excluded from the depletion base. These costs are expected to be evaluated within the next three years. These costs consist primarily of acreage acquisition costs and related geological and geophysical costs.

RESULTS OF OPERATIONS FROM OIL AND NATURAL GAS PRODUCING ACTIVITIES
(thousands of dollars)

		YEAR ENDED DECEMBER
	2002	2001
Oil and natural gas revenues	$ 106,992	$ 176,64

Less:		
Oil and natural gas operating costs	11,935	16,62
Severance and ad valorem taxes	8,235	11,76
Depletion	59,799	65,98
Impairment of long-lived assets	69,124	6,58
Income tax	(22,002)	13,50
	127,091	114,44
Results of operations from oil and natural gas producing activities	$ (20,099)	$ 62,19
Depletion expense per Mcfe	$ 2.07	$ 1.6

ESTIMATED QUANTITIES OF PROVED RESERVES

The following table sets forth the net proved reserves of the Company as of December 31, 2002, 2001 and 2000, and the changes therein during the years then ended. The reserve information was reviewed by T. J. Smith & Company, Inc., independent petroleum engineers, for 2002, 2001 and 2000. All of the Company's oil and natural gas producing activities are located in the United States.

	Oil (MBbls
TOTAL PROVED RESERVES:	
BALANCE AT DECEMBER 31, 1999	27,355
Production during 2000	(3,987
Discoveries and extensions	3,103
Sale of reserves-in-place	(369
Revisions of previous quantity estimates and other	(3,761
BALANCE AT DECEMBER 31, 2000	22,341
Production during 2001	(2,918
Discoveries and extensions(1)	11,605
Sale of reserves-in-place	(5,558
Revisions of previous quantity estimates and other	(1,124
BALANCE AT DECEMBER 31, 2001	24,346
Production during 2002	(2,213
Discoveries and extensions	41
Revisions of previous quantity estimates and other(1)	(12,249
BALANCE AT DECEMBER 31, 2002	9,925
PROVED DEVELOPED RESERVES:	
Balance at December 31, 2002	6,841
Balance at December 31, 2001	10,752
Balance at December 31, 2000	15,549
Balance at December 31, 1999	17,695

(1) Primarily as a result of Kent Bayou. See Note 3 to Notes to Consolidated Financial Statements for additional information.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The information that follows has been developed pursuant to SFAS No. 69 and utilizes reserve and production data prepared or reviewed by independent petroleum consultants. Reserve estimates are inherently imprecise and estimates of new discoveries are less precise than those of producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The estimated discounted future net cash flows from estimated proved reserves are based on prices and costs as of the date of the estimate unless such prices or costs are contractually determined at such date. Actual future prices and costs may be materially higher or lower. Actual future net revenues 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. Future income tax expense has been reduced for the effect of available net operating loss carryforwards.

(thousands of dollars)	AT DEC
	2002
Future cash flows	$ 829,538
Future production costs	(137,215)
Future development costs	(43,474)
Future net cash flows before income taxes	648,849
Future taxes on income	(99,852)
Future net cash flows	548,997
Discount to present value at 10 percent per annum	(119,162)
Standardized measure of discounted future net cash flows	$ 429,835

The average price for natural gas in the above computations was $4.96 and $2.63 per Mcf at December 31, 2002 and 2001, respectively. The average price used for crude oil in the above computations was $31.82 and $19.41 per Bbl at December 31, 2002 and 2001, respectively.

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The following table sets forth the changes in standardized measure of discounted future net cash flows for the years ended December 31, 2002, 2001 and 2000 (thousands of dollars):

	YEAR ENDED DECEMBE	
	2002	2001
Balance at Beginning of Period	$ 402,917	$ 992,254
Sales of oil and gas, net of production costs	(86,822)	(148,260
Changes in sales & transfer prices, net of production costs	348,960	(795,374
Revisions of previous quantity estimates	(373,928)	(38,680
Sales of reserves-in-place	--	(199,245
Current year discoveries, extensions and improved recovery	40,376	190,073
Changes in estimated future development costs	(9,840)	(11,366
Development costs incurred during the period	38,998	30,471
Accretion of discount	40,292	99,225
Net change in income taxes	(3,676)	319,905
Change in production rates (timing) and other	32,558	(36,086
Net change	26,918	(589,337
Balance at End of Period	$ 429,835	$ 402,917

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

Not applicable.

PART III

The information required in Items 10, 11, 12, 13, 14 and 15 is incorporated by reference to the Company's definitive Proxy Statement to be filed with the Securities and Exchange Commission on or before April 30, 2003.

PART IV

ITEM 16. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) Documents filed as part of this report:

1. Financial Statements included in Item 8:

(i) Independent Auditor's Report

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

(iii) Consolidated Statements of Operations for each of the three years in the period ended December 31, 2002

(iv) Consolidated Statements of Changes in Stockholders' Equity for each of the three years in the period ended December 31, 2002

(v) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2002

(vi) Notes to Consolidated Financial Statements

(vii) Consolidated Supplemental Oil and Gas Information (Unaudited)

2. Financial Statement Schedule:

(i) All schedules are omitted as they are not applicable, not required or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits:

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**99.3	Certificate of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**99.4	Certificate of Chief Accounting Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Management contract or compensation plan.

**Filed herewith.

(b) Reports on Form 8-K.

None

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.

THE MERIDIAN RESOURCE CORPORATION

BY: /s/ JOSEPH A. REEVES, JR.

Chief Executive Officer
(Principal Executive Officer)
Director and Chairman of the Board

Date: April 15, 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.

Name	Title
BY: /s/ JOSEPH A. REEVES, JR. Joseph A. Reeves, Jr.	Chief Executive Officer (Principal Executive Officer) Director and Chairman of the Board
BY: /s/ MICHAEL J. MAYELL Michael J. Mayell	President and Director
BY: /s/ JAMES H. SHONSEY James H. Shonsey	Chief Financial Officer

BY: /s/ LLOYD V. DELANO Lloyd V. DeLano	Chief Accounting Officer
BY: /s/ JAMES T. BOND James T. Bond	Director
BY: /s/ JOE E. KARES Joe E. Kares	Director
BY: /s/ GARY A. MESSERSMITH Gary A. Messersmith	Director

CERTIFICATIONS

I, Joseph A. Reeves, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of The Meridian Resource 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 we 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 function):

(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

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6. The registrant's other certifying officers and I have indicated in this annual report whether or not 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 15, 2003

/s/ Joseph A. Reeves, Jr.

Joseph A. Reeves, Jr.
Chief Executive Officer

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CERTIFICATIONS

I, Michael J. Mayell, certify that:

1. I have reviewed this annual report on Form 10-K of The Meridian Resource 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 we 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 function):

(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 or not 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 15, 2003

/s/ Michael J. Mayell

Michael J. Mayell
President

CERTIFICATIONS

I, James H. Shonsey, certify that:

1. I have reviewed this annual report on Form 10-K of The Meridian Resource 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;

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   (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 internal controls; and

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6. The registrant's other certifying officers and I have indicated in this annual report whether or not 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 15, 2003

/s/ James H. Shonsey

James H. Shonsey
Chief Financial Officer

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CERTIFICATIONS

I, Lloyd V. DeLano, certify that:

1. I have reviewed this annual report on Form 10-K of The Meridian Resource 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;

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6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal

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Date: April 15, 2003

/s/ Lloyd V. DeLano

Lloyd V. DeLano
Chief Accounting Officer

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None