MERIDIAN RESOURCE CORP
Form 10-K
March 16, 2005

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, 2004   Commission file number: 1-10671

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

TEXAS (State of incorporation)	76-0319553 (I.R.S. Employer Identification No.)

1401 ENCLAVE PARKWAY, SUITE 300, HOUSTON, TEXAS (Address of principal executive offices)	77077 (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
Rights to Purchase Preferred Shares	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, 2004	$495,384,386
Number of shares of common stock outstanding at March 1, 2005:	79,215,394

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form (Items 10, 11, 12, 13 and 14) is incorporated by reference from the registrant's Proxy Statement to be filed on or before May 2, 2005.

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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, 2004, we had proved reserves of 139 Bcfe with a present value of future net cash flows before income taxes of approximately $545 million. The Company does not have any proved undeveloped reserves assigned to its Biloxi Marshlands project area. Seventy-three percent (73%) of our proved reserves were natural gas and approximately eighty-two percent (82%) were classified as proved developed.

We believe that we are among the leaders in the industry in the application of 3-D seismic technology. 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.

Historically, Meridian's experienced technical team has internally generated the majority of the Company's exploration projects. In addition, the Company generally serves as the operator through all phases of drilling, completing and producing its exploration and development projects. During the course of the prior 13 years, we have generated and participated in the discovery of approximately 800 Bcfe of new reserves. Recently, we have added to our business strategy the pursuit and development of shallower (above or just into geo-preserved sections), lower-risk exploration projects that we believe provide the Company better control of risks and costs than a purely deep exploration strategy that the Company 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 the level of costs justify the risks associated with such opportunities. In addition, the Company has introduced into its business plan, a more aggressive review of the acquisition of proven reserves that also contain exploration, exploitation and development upside in our area of focus.

We currently have interests in leases and options to lease acreage in approximately 300,000 gross acres in Louisiana, Texas and the Gulf of Mexico. We also have rights or access to approximately 8,000 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. We are aggressively pursuing the reprocessing of our 3-D inventory for the development of new exploration plays similar to those defined by our Biloxi Marshlands play. We have tested the first of such exploration concepts at the Company's Turtle Island Prospect and recently logged approximately 80 feet of apparent hydrocarbons.

The Meridian Resource Corporation was incorporated in Texas in 1990, with headquarters located at 1401 Enclave Parkway, Suite 300, Houston, Texas 77077. The Company's common stock is traded on the New York Stock Exchange under the ticker symbol "TMR." You can locate additional information, including the Company's filings with the Securities and Exchange Commission, 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 well and multiple potential targets to maximize the profitability and increase of 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.

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 focus region of 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, and interprets the 3-D data utilizing Schlumberger's GeoQuest interpretative software, where all of the respective disciplines interact to develop the final product. Substantially 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.

The process of developing, reviewing and analyzing a prospect from the time we first identify it to the time that we drill 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, provides a greater cost savings to the Company. 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 100% 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. Our working interests in offshore properties 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.

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 probability of success and reduces our dry-hole costs compared to companies that do not engage in a similar process and that our people, their knowledge and experience, particularly in our focus region, provide us with a competitive advantage.

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, 2004. The reserve volumes were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	LOUISIANA	GULF OF MEXICO	TOTAL
PRODUCTION FOR THE YEAR ENDED DECEMBER 31, 2004			
Oil (MBbls)	1,133	137	1,270
Natural Gas (MMcf)	26,249	1,590	27,839
RESERVES AS OF DECEMBER 31, 2004			
Oil (MBbls)	5,377	987	6,364
Natural Gas (MMcf)	92,554	8,445	100,999
ESTIMATED FUTURE NET CASH FLOWS ($000)			$719,375
PRESENT VALUE OF FUTURE NET CASH FLOWS BEFORE INCOME TAXES ($000)(1)			$544,688
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS ($000)(1)			$470,357

(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, 2004, we used the prices at December 31, 2004, which were $42.33 per Bbl of oil and $6.40 per Mcf of natural gas and do not reflect the impact of hedges.

PRODUCTIVE WELLS

At December 31, 2004, 2003 and 2002, we held interests in the following productive wells. As of December 31, 2004, we own 26 gross (4.5 net) wells in the Gulf of Mexico which are outside operated and net to 1.5 oil wells and 3.0 natural gas wells. In addition, of the total well count for 2004, 4 wells (1.4 net) are multiple completions.

	2004		2003		2002	
	GROSS	NET	GROSS	NET	GROSS	NET
Oil Wells...........	35	22	31	20	67	42
Natural Gas Wells...	68	34	60	27	71	28
Total............	103	56	91	47	138	70

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, 2004. 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 estimates were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	PROVED RESERVES AT DECEMBER 31, 2004			
	DEVELOPED PRODUCING	DEVELOPED NON-PRODUCING	UNDEVELOPED	TOTAL
	(DOLLARS IN THOUSANDS)			
Net Proved Reserves:				
Oil (MBbls)..............................	2,285	2,431	1,648	6,364
Natural Gas (MMcf).......................	41,928	43,579	15,492	100,999
Natural Gas Equivalent (MMcfe)...........	55,638	58,165	25,380	139,183
Estimated Future Net Cash Flows...........				$719,375
Present Value of Future Net Cash Flows (before income taxes)(1)...............				$544,688
Standardized Measure of Discounted Future Net Cash Flows(1)..............				$470,357

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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, 2004, we used the prices at December 31,

2004, which were $42.33 per Bbl of oil and $6.40 per Mcf of natural gas and do not reflect the impact of hedges.

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. 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 2004, 2003 and 2002.

	GROSS WELLS			NET WELLS		
	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL
EXPLORATORY WELLS						
Year ended December 31, 2004...	16	11	27	14.7	8.9	23.6
Year ended December 31, 2003...	5	1	6	3.8	0.4	4.2
Year ended December 31, 2002...	6	1	7	3.7	0.9	4.6
DEVELOPMENT WELLS						
Year ended December 31, 2004...	4	--	4	3.2	--	3.2
Year ended December 31, 2003...	--	1	1	--	0.9	0.9
Year ended December 31, 2002...	2	1	3	1.4	0.9	2.3

Meridian had 3 gross (2.4 net) wells in progress at December 31, 2004.

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 2004, 2003 and 2002.

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
PRODUCTION:			
Oil (MBbls)........................	1,270	1,403	2,213
Natural gas (MMcf).................	27,839	20,142	15,578
Natural gas equivalent (MMcfe)......	35,457	28,563	28,856
AVERAGE PRICES:			
Oil ($/Bbl)........................	$ 28.40	$ 24.97	$ 24.67
Natural gas ($/Mcf)................	$ 5.98	$ 5.07	$ 3.36
Natural gas equivalent ($/Mcfe).....	$ 5.71	$ 4.80	$ 3.71
PRODUCTION EXPENSES:			
Lease operating expenses ($/Mcfe)...	$ 0.40	$ 0.39	$ 0.41
Severance and ad valorem Taxes ($/Mcfe).....................	$ 0.26	$ 0.27	$ 0.29

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, 2004. 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, 2004			
	DEVELOPED		UNDEVELOPED	
REGION	GROSS	NET	GROSS	NET
LOUISIANA........	33,305	19,632	38,673	34,618
GULF OF MEXICO...	34,518	6,098	7,500	5,033
TOTAL.........	67,823	25,730	46,173	39,651

In addition to the above acreage, we currently have options or farm-ins to acquire leases on approximately 185,806 gross (163,748 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. Our undeveloped acreage, including optioned acreage, expires during the next three years at the rate of 154,000 acres in 2005, 12,000 acres in 2006, and 26,000 acres in 2007.

GEOLOGIC/LAND AND OPERATIONS GEOPHYSICAL EXPERTISE

Meridian employs approximately 68 full-time non-union employees and six contract employees. This staff includes geologists, geophysicists, land and engineering staff with over 480 combined years of experience in generating and developing onshore and offshore prospects in the Louisiana and Texas Gulf Coast region. Our geologists and geo-physicists generate and review all prospects using 2-D and 3-D seismic technology and analogues to producing wells in the areas of interest.

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 posted prices, less applicable transportation deductions, and the natural gas is sold at posted indices, less applicable transportation, gathering and dehydration charges, adjusted for the quality of natural gas and prevailing supply and demand conditions. The natural gas production is sold under long- and short-term contracts (all of which are based on a published index) 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 2004, 2003 and 2002.

	YEAR ENDED DECEMBER 31,		
CUSTOMER	2004	2003	2002
Superior Natural Gas........	45%	19%	--
Louisiana Intrastate Gas....	22%	24%	17%
Conoco, Inc.................	--	10%	12%
Equiva Trading Company(1)...	--	--	33%

(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 our results of operations.

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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 1993, prices for West Texas Intermediate crude have ranged from $8.00 to $53.09 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, 2004, was $5.71 per Mcfe compared to $4.80 per Mcfe during the year ended December 31, 2003. 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 is 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 Federal Energy Regulatory Commission ("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 other 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

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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 principal 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 75% 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.

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ITEM 2. PROPERTIES

PRODUCING PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

PETROQUEST LITIGATION. This litigation was settled in December 2003 and all claims were dismissed. In December 1999, PetroQuest Energy, Inc. (formerly known as Optima Energy (U.S.) Corporation) ("PetroQuest") filed a claim against Meridian for damages "estimate[d] to exceed several million dollars" alleging that Meridian was liable for gross negligence and willful misconduct in the execution of certain agreements related to property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish and for an alleged withholding of funds totaling $886,153.31, in conjunction with Meridian's having paid a prior adverse judgment in favor of Amoco Production Company. Meridian filed an answer denying PetroQuest's claims and asserted a counterclaim for attorney's fees, court costs and other expenses and for declaratory relief that Meridian is entitled to retain the amounts (with all interest thereon) that it had suspended from disbursement to PetroQuest. Under the confidential settlement agreement, Meridian agreed to make two payments which have now been made. The settlement amount was fully reflected in the financial statements at December 31, 2003. Judgments of dismissal were signed in January 2004.

RAMOS TITLE LITIGATION. This litigation was settled in March 2004 and all claims were dismissed. Three different groups asserted adverse title claims to some or all of Section 80 (640 acres) within Meridian's Thibodaux units in the Ramos Field. Another entity asserted adverse title claims to a portion of Section 36 within these same units. These claims turned primarily on the location of the parish boundary lines between Terrebonne and Assumption Parishes and/or the validity of various tax sales in the chain of title. Meridian's gas purchaser, Louisiana Intrastate Gas Company LLC ("LIG"), deposited into the Terrebonne Parish court registry certain gas and plant-product proceeds attributable to 25 acres within these units since October 2000, and Meridian suspended payment of royalties and working interest attributable to these same 25 acres since December 2000. Meridian and its partners and royalty owners reached an agreement whereby the parties' plaintiff granted a lease on all of the disputed acreage to the current interest owners for a lease bonus of $4.5 million and a future royalty interest of 1.5%.

H. L. HAWKINS LITIGATION. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages "estimated to exceed several million dollars" for Meridian's alleged gross negligence and willful misconduct under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish, as a result of Meridian's satisfying a prior adverse judgment in favor of Amoco Production Company. Meridian will file an answer denying Hawkins' claims and assert a counterclaim for attorney's fees, court costs and other expenses, and for declaratory relief that Meridian is entitled to retain the amounts that it had been paid by Hawkins. The Company has not provided any amount for this matter in its financial statements at December 31, 2004.

ENVIRONMENTAL LITIGATION. Various landowners have sued Meridian (along with numerous other oil companies) in various similar lawsuits concerning the Weeks Island, Gibson, Bayou Pigeon, West Lake Verret and White Castle Fields. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs' lands from alleged contamination and otherwise from the defendants' oil and gas operations.

There are no other material legal proceedings which exceed our insurance limits to which the Company or any of its subsidiaries 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

At the annual meeting of shareholders held on October 27, 2004, the Company's shareholders elected three Class I Directors, three Class II Directors and one Class III Director. The following summarizes the number of votes for and against each nominee:

Nominee	For	Withheld	Broker Non-Vote
David W. Tauber (I)	72,088,348	2,325,337	4,225,809
John B. Simmons (I)	72,082,852	2,330,833	4,225,809
James R. Montague (I)	72,751,131	1,662,554	4,225,809
E. L. Henry (II)	72,747,701	1,665,984	4,225,809
Joe E. Kares (II)	71,071,018	3,342,667	4,225,809
Gary A. Messersmith (II)	71,368,967	3,044,718	4,225,809
Fenner R. Weller, Jr. (III)	71,982,852	2,430,833	4,225,809

Directors Joseph A. Reeves, Jr. and Michael J. Mayell are not up for re-election for another three-year term until the 2005 annual meeting.

Also at the 2004 annual meeting, shareholders voted on a shareholder proposal that the Company nominate at least two candidates for each Board of Directors position to be voted on by the shareholders. The proposal did not receive the requisite number of votes for approval. The following summarizes the number of votes for and against such proposal.

For	Against	Abstain	Broker Non-Vote
9,265,077	28,160,038	274,071	36,714,499

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
2004:		
First quarter	$6.37	$5.21
Second quarter ...	7.55	6.13
Third quarter	8.97	6.89
Fourth quarter ...	8.95	5.52
2003:		
First quarter	$1.78	$0.94
Second quarter ...	4.73	0.92
Third quarter	5.16	4.00
Fourth quarter ...	6.14	3.88

The closing sale price of the Common Stock on March 1, 2005, as reported on the New York Stock Exchange Composite Tape, was $6.01. As of March 1, 2005, we had approximately 790 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 any cash dividends on Common Stock or for purchase of shares of Common Stock without the prior consent of the lender.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information as of December 31, 2004, with respect to our compensation plans (including individual compensation arrangements) under which equity securities are authorized for issuance:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of remaining av future issu equity compen (excluding reflected in c
Equity compensation plans approved by security holders	6,725,478	$3.60	1,670
Equity compensation plans not approved by security holders	--	--	
Total	6,725,478	$3.60	1,670

(1) Does not include 3,600,000 shares which have been reserved for issuance in lieu of cash compensation under the Company's deferred compensation plan, which plan was approved by security holders.

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ITEM 6. SELECTED FINANCIAL DATA

All financial data should be read in conjunction with our Consolidated Financial Statements and related notes thereto included in Item 8 and elsewhere in this report.

	YEAR ENDED DECEMBER 31,				
	2004	2003	2002	2001	2000
	(In thousands, except prices and per share information)				
A. SUMMARY OF OPERATING DATA					
Production:					
Oil (MBbls)	1,270	1,403	2,213	2,918	3,987
Natural gas (MMcf)	27,839	20,142	15,578	22,085	27,672
Natural gas equivalent (MMcfe)	35,457	28,563	28,856	39,594	51,596
Average Prices:					
Oil ($/Bbl)	$ 28.40	$ 24.97	$ 24.67	$ 25.17	$ 27.32
Natural gas ($/Mcf)	5.98	5.07	3.36	4.67	4.14
Natural gas equivalent ($/Mcfe)	5.71	4.80	3.71	4.46	4.33
B. SUMMARY OF OPERATIONS					
Total revenues	$203,118	$137,479	$107,470	$178,060	$226,246
Depletion and depreciation	102,915	75,441	60,972	67,450	69,648
Net earnings (loss)(1)	29,248	7,246	(52,012)	22,551	65,070
Net earnings (loss) per share:(1)					
Basic	$ 0.41	$ 0.14	$ (1.05)	$ 0.47	$ 1.34
Diluted	0.37	0.13	(1.05)	0.43	1.06
Dividends per:					
Common share	--	--	--	--	--
Redeemable preferred share	$ 8.50	$ 8.50	$ 5.90	--	--
Preferred share	$ --	$ --	$ --	$ 0.11	$ 1.36
Weighted average common shares outstanding - Basic	72,084	53,325	49,763	48,350	48,646

C. SUMMARY BALANCE SHEET DATA

Total assets	$512,392	$448,400	$456,240	$507,900	$570,921
Long-term obligations, inclusive of current maturities	75,129	152,320	203,750	210,000	250,000
Redeemable preferred stock	31,589	60,446	69,690	--	--
Stockholders' equity	316,041	184,335	133,393	188,221	270,322

(1) Applicable to common stockholders.

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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.

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 proven successful. During the period of 1992-2004, Meridian generated and participated in the discovery of approximately 800 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 wells 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 approximately 8,000 square miles of 3-D seismic data, our technical and professional staff is in a 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, development and acquisition of a risk balanced portfolio of high potential projects;

- Maintain a concise geographic focus in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico, applying professional and technical knowledge and experience to the development of a high quality project inventory;

- Apply a rigorous methodology utilizing 3-D seismic technology in the generation and development of lower risk exploration prospects, maximize our 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.

As of December 31, 2004, we had proved reserves of 139 Bcfe, approximately 73% of which were natural gas, with a present value of future pre-tax cash flows (PV-10) of $545 million. We own interests in approximately 300,000 gross (229,000 net) acres, including 18 fields and 103 wells, and we operate approximately 87% of our total production.

Our reserves, strategic acreage position and 2-D and 3-D seismic data base provide us with a significant presence in our areas of focus, enabling us to exploit a large asset base adding to our multi-year prospect inventory of exploratory and development plays and prospects, at a low incremental costs relative to our competition. We own over 8,000 square miles of 3-D seismic data.

It is no accident that we have focused in the Gulf Coast region of southeast Texas and south Louisiana. Although we have drilled and operated in over 12 states and almost every producing basin in the domestic United States--Appalachia, Mid-Continent, Rocky Mountains, Arkoma, west Texas, south Texas, Louisiana and the Gulf of Mexico shelf. We chose this particular province because it presented the greatest opportunity for growth though exploration and exploitation. Complex geological fault traps capable of being resolved with 3-D seismic and computer-aided technology by a company willing to adopt it earlier than others, meant opportunities for by-passed reserves. Highly prolific, potentially stacked producing sands with high producing rates compared to other regions meant lower risk for failure and quicker return of investments from successful wells. We were successful with our efforts generating and/or participating in the discovery of over 800 Bcfe.

Yet, we recognized that long lead times were required to generate deep exploration targets and that the ability to use the technology to place the wells in optimum positions, high on structures and within traps frequently resulted in single well prospects that required a continual treadmill of exploration prospecting. The result was a perception of greater risk to replace high flow rates and returns with a 4-7 year reserve life rather than the much lower-rate, longer lived plays in other regions. During 2002, we expanded our business plan to include lower-risk, multiple-well "play" opportunities using the seismic technology to identify what we believe are hydrocarbon indicators in shallower sections than we have historically drilled. To date, we have been successful in the generation and development of several such plays, the first of which was the Company's Thornwell field in Cameron Parish, Louisiana during 1999.

Since that time, we have successfully added our Biloxi Marshlands project area, a play that has expanded and complemented our exploration strategy with a uniquely large play that essentially gives Meridian control over approximately 400,000 contiguous acres with proprietary 3-D seismic covering over 400 square miles. We have used these resources to identify multiple shallower, low-risk prospects in the area we believe will extend our drilling and producing operations for several years. The successful drilling and resulting increases in production and cash flows from this play, together with the convergence of higher commodity prices, has significantly improved the financial condition of the Company, its capital structure, balance sheet and liquidity, all of which combined with our large prospect inventory, provide the Company with the potential for a very promising 2005. These include -

- Earnings per share applicable to common shareholders increased by 306%.

- Average daily production increased by 24% on a Mcf equivalent basis.

- Total revenues increased by 48% to $203.1 million.

- Discretionary cash flow increased by 59%, or $59.2 million to $159.8 million.

- Net cash provided by operating activities increased by 87% to $171.5 million.

- Debt to total capitalization declined to 18%.

There has been a lot of talk about the Biloxi Marshlands play recently--its merits and future opportunity. Simply put, Biloxi is a cornerstone project for the Company, one that not only confirmed our decision that we could reduce our exploration risk profile in an area that was written off by many as over-explored, but also one that has served as a prelude to the other similar plays that we believe exist throughout our region of focus and where we own over 8,000 square miles of 3-D seismic data. Since inception in 2003, we have drilled 31 wells at Biloxi. Of them, 20 have been completed as producers with 10 wells either plugged and abandoned or determined to be uneconomic, and one well currently drilling. We have purchased and acquired public and proprietary 3-D seismic data in the area totaling over 700 square miles, with plans to shoot an additional 137 square miles during 2005. With over 400 square miles of 3-D seismic proprietary data, we have been successful at State of Louisiana lease sales with the purchase of 103 of the 105 state tracts bid on, resulting in the acquisition of approximately 23,087 acres of state water bottoms over geological leads identified by the Company.

Since December 2002, when we acquired our first land and seismic positions at Biloxi, the Company has expended a total of approximately $147 million for all land, seismic, drilling and completions, production facilities and pipelines, over both evaluated and unevaluated areas. We have received net field cash flow since first production in March 2003, or under two years, of $129 million. Biloxi Marshlands represents a major and unique expansion of our Company's exploration efforts in our region of focus. The project represents the reality of a vision expanded by the hard work by a team of highly skilled and knowledgeable professionals who made a commitment to redefine an exploration plan that has positioned our Company to move forward to new and similar multiple-prospect, multiple well, lower-risk exploration opportunities as the industry experiences a declining domestic reserve base.

Management is committed to exploring the entire position in this play ensuring our knowledge base for elections of acreage positions prior to the expiration of our option period. With the extensions to the south and east of our original discovery at Atlas, we have successfully developed new and better processing and interpretive techniques that have provided a higher level of confidence for our future drilling efforts, not only at Biloxi but also as we have taken and applied them to other in-house surveys and extended the exploratory concept in our region, our back-yard.

With this knowledge base and experience base, we have defined multiple other such prospect opportunities which will be drilled and tested during 2005 and which we believe have similar trapping conditions and producing characteristics as Biloxi. The Company has set its capital budget at approximately $140 million for new prospect opportunities ranging in depths from shallow to deep, exposing the Company to unrisked reserves of approximately 200 Bcfe.

Review of 2004. During 2004, the Company focused on corporate fundamentals--financial, seismic, land and production. The Company reduced total debt by $77.2 million, reducing its Senior Bank facility from $122.3 million to $75.1 million and sub-debt in full from $20 million. In addition, outstanding Preferred Stock was reduced from a high of $72 million in stated value of shares outstanding, to approximately $31.6 million as a result of conversions to common stock. By year end 2004, the Company's debt to book capitalization had been reduced from 38% to 18%.

During 2004, 20 wells were brought on line, increasing the 2003 average production from 78.3 Mmcfe per day to 96.9 Mmcfe per day or a 24% increase. During 2005, Meridian expects to further increase its reserves,

production cash flow and earnings as a result of its strong inventory of prospects and 3-D data base.

Recent Developments. In furthering its focus on organic growth, the Company is continuing to develop its Biloxi Marshlands and similar plays in south Louisiana. Currently the Company's South Apollo prospect is expected to be placed on production within 10-15 days; the Turtle Island Well is expected to be placed on production within 30 days; the Hornet 5 Well has been drilled to its total depth and is expected to be logged and tested during March 2005.

During the last several months, the Company has participated in several State of Louisiana oil and gas lease sales and during 2004 successfully bid on 103 of 105 additional tracts in the area, covering 23,088 acres in and around our current lease holdings. It is believed that our high rate of success is because we hold the only proprietary 3-D seismic over the area.

In an effort to further its development in the Biloxi project area for future years, the Company began the third phase of its 3-D seismic program in January 2005. This approximately 137-square mile 3-D seismic survey is expected to be completed in May 2005. Although Meridian's focus is currently on the Cris I geological time horizon, the survey is designed to look at all shallow and deep objectives.

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, 2004 was $5.71 per Mcfe compared to $4.80 per Mcfe during the year ended December 31, 2003. 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., Quantitative and Qualitative Disclosures about Market Risk, 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.

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RESULTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2004, COMPARED TO YEAR ENDED DECEMBER 31, 2003

Oil and natural gas revenues, which include oil and natural gas hedging activities (see note 12 of notes to consolidated financial statements), during the twelve months ended December 31, 2004, increased $65.3 million (48%) as compared to 2003 revenues due primarily to a 24% increase in production volumes primarily from the Company's previously announced drilling results in the Biloxi Marshlands ("BML") project area and Weeks Island, coupled with successful workover operations in the Company's Ramos and Weeks Island fields, partially offset by natural production declines and property sales during 2003. Further, revenues were enhanced by a 19% increase in average commodity prices on a natural gas equivalent basis. Drilling and workover success increased our average daily production from 78.3 Mmcfe during 2003 to 96.9 Mmcfe for 2004. Oil and natural gas production volume totaled 35,457 Mmcfe for 2004, compared to 28,563 Mmcfe for 2003. During 2004, the Company's drilling activity was primarily focused in the Biloxi Marshlands ("BML") project area and the Weeks Island field. During 2004, the Company drilled or participated in the drilling of 31 wells of which 20 wells were completed and placed on production, representing a 65% success rate. The following table summarizes Meridian's operating revenues, production volumes and average sales prices for the years ended December 31, 2004 and 2003.

	Year Ended December 31, 2004	Year Ended December 31, 2003	Increase (Decrease)
Production:			
Oil (MBbls)	1,270	1,403	(10%)
Natural gas (MMcf)	27,839	20,142	38%
Natural gas equivalent (MMcfe)	35,457	28,563	24%
Average Sales Price:			

Oil (per Bbl)	$ 28.40	$ 24.97	14%
Natural gas (per Mcf)	5.98	5.07	18%
Natural gas equivalent (per Mcfe)	5.71	4.80	19%
Operating Revenues (000's):			
Oil	$ 36,060	$ 35,032	3%
Natural gas	166,387	102,092	63%
Total	$202,447	$137,124	48%

Operating Expenses.

Oil and natural gas operating expenses on an aggregate basis increased $2.7 million (25%) to $14.0 million in 2004, compared to $11.3 million in 2003. On a unit basis, lease operating expenses increased $0.01 per Mcfe to $0.40 per Mcfe for the year 2004 from $0.39 per Mcfe for the year 2003. Oil and natural gas operating expenses increased primarily due to additional operating expenses associated with new wells and facilities in the BML project area and to increased workover activity in the Weeks Island, Ramos and Turtle Bayou fields during the year, partially offset by savings resulting from sold properties in the latter portion of 2003, combined with other cost savings initiated during the current year. In 2005, we expect our anticipated future increases in production to result in a continued reduction in operating costs on a per unit level.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes increased $1.8 million (23%) to $9.4 million in 2004, compared to $7.6 million in 2003, primarily because of an increase in natural gas production and a higher natural gas tax rate,

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partially offset by a tax refund from Louisiana for prior periods. Meridian's oil and natural gas production is primarily from Louisiana and is therefore subject to Louisiana severance tax. The severance tax rates for Louisiana are 12.5% of gross oil revenues and $0.208 per Mcfe (effective July 1, 2004) for natural gas. For the first six months of 2004, and the last six months of 2003, the rate was $0.171 per Mcf for natural gas, an increase from $0.122 per Mcf for the first half of 2003. On an equivalent unit of production basis, severance and ad valorem taxes decreased to $0.26 per Mcfe for 2004 from $0.27 per Mcfe for 2003, reflecting a tax refund from Louisiana for prior periods. The per Mcfe cost for 2005 will increase due to a higher anticipated average severance tax rate than what was experienced in 2004.

Depletion and Depreciation.

Depletion and depreciation expense increased $27.5 million (36%) during 2004 to $102.9 million compared to $75.4 million for 2003. This was primarily the result of the 24% increase in production volumes in 2004 over 2003 levels, and an increase in the depletion rate as compared to the 2003 period. On a unit basis, depletion and depreciation expenses increased to $2.90 per Mcfe for 2004, compared to $2.64 per Mcfe for 2003. We are expecting a downward trend in our 2005 depletion rate as we find and develop new reserves during the year.

General and Administrative Expense.

General and administrative expenses, which are net of costs capitalized in our oil and gas properties (see note 18 of notes to consolidated financial statements), increased $3.6 million (31%) to $15.2 million in 2004 compared to $11.6 million for the year 2003, primarily due to an increase in accounting and professional fees associated with implementing the expanded compliance burden required by the Sarbanes-Oxley Act of 2002, an increase in insurance costs primarily due to additional coverage and to increased production activity. On an equivalent unit of production basis, general and administrative expenses increased $0.02 per Mcfe to $0.43 per Mcfe for 2004 compared to $0.41 per Mcfe for 2003. In 2005, we anticipate a reduction in accounting and professional fees.

Interest Expense.

Interest expense decreased $4.3 million (38%) to $7.2 million in 2004 compared to $11.5 million for 2003. The decrease was primarily a result of the reduction in long-term borrowings. With the conversion of the $20 million convertible subordinated notes into common stock and the 2004 net repayments of $57.2 million on our long-term debt, the Company will realize additional future savings in interest. The reduction in long-term debt was partly the result of our August 2004 common stock offering.

Taxes on Income.

The provision for income taxes for 2004 was $19.3 million as compared to $4.2 million for 2003. Income taxes were provided on book income after taking into account permanent differences between book income and taxable income, and after reducing the income tax valuation allowance by $2.7 million in 2003.

Adoption of Statement of Financial Accounting Standards No. 143.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations." As a result, the Company began recording long-term liabilities representing the discounted present value of the estimated asset retirement obligations with offsetting increases in capitalized oil and gas properties. This liability will continue to be accreted to its future value in subsequent reporting periods. The Company has charged approximately $0.6 million and $0.7 million to earnings as accretion expense during 2004 and 2003, respectively. In 2003, the Company recorded a long-term liability of $4.5 million representing the discounted present value of the estimated retirement obligations and an increase in capitalized oil and gas properties of $3.2 million. The cumulative effect of the change in accounting principle for 2003 totaled $1.3 million or $0.02 per share, and was charged to earnings in 2003.

YEAR ENDED DECEMBER 31, 2003, COMPARED TO YEAR ENDED DECEMBER 31, 2002

Oil and natural gas revenues, which include oil and natural gas hedging activities (see note 12 of notes to consolidated financial statements), increased $30.1 million, primarily as a result of an increase in average commodity prices. The following table summarizes Meridian's operating revenues, production volumes and average sales prices for the years ended December 31, 2003 and 2002.

	Year Ended December 31,		
	2003	2002	Increase (Decrease)

Production:			
Oil (MBbls)	1,403	2,213	(37%)
Natural gas (MMcf)	20,142	15,578	29%
Natural gas equivalent (MMcfe)	28,563	28,856	(1%)
Average Sales Price:			
Oil (per Bbl)	$ 24.97	$ 24.67	1%
Natural gas (per Mcf)	5.07	3.36	51%
Natural gas equivalent (per Mcfe)	4.80	3.71	29%
Operating Revenues (000's):			
Oil	$ 35,032	$ 54,595	(36%)
Natural gas	102,092	52,397	95%
Total	$137,124	$106,992	28%

Operating Expenses.

Oil and natural gas operating expenses decreased $0.6 million to $11.3 million in 2003, compared to $11.9 million in 2002. Lease operating expenses reflected savings realized on sold properties combined with other cost savings offset by additional operating expenses associated with the Biloxi Marshlands project area. On a unit basis, lease operating expenses decreased $0.02 per Mcfe to $0.39 per Mcfe for the year 2003 from $0.41 per Mcfe for the year 2002.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes decreased $0.6 million to $7.6 million in 2003, compared to $8.2 million in 2002. This decrease was largely attributable to the decrease in the average tax rate for natural gas and the decrease in oil revenues from the 2002 levels, partially offset by an increase in natural gas production. 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 $0.171 per Mcf for natural gas (effective July 2003). The tax rate for natural gas for the first half of 2002 was $0.199 per Mcf and from July 2002 through June 2003 was $0.122 per Mcf. On an equivalent unit of production basis, severance and ad valorem taxes decreased to $0.27 per Mcfe from $0.29 per Mcfe for the comparable period.

Depletion and Depreciation.

Depletion and depreciation expense increased $14.4 million to $75.4 million in 2003 from $61.0 million for 2002. This increase was primarily a result of an increased depletion rate from 2002 levels, partially offset by the 1% decrease in production on an Mcfe basis from the comparable period in 2002. On a unit basis, depletion and depreciation expenses increased to $2.64 per Mcfe for 2003, compared to $2.11 per Mcfe for 2002. The increase in the depletion rate was primarily a result of the 2002 impairment of long-lived assets mentioned below.

General and Administrative Expense.

General and administrative expenses, which are net of costs capitalized in our oil and gas properties (see note 18 of notes to consolidated financial statements), decreased $0.2 million to $11.6 million in 2003 compared to $11.8 million for the year 2002. During the first quarter of 2003 the Company initiated reductions in staff to reflect a change in exploration strategy to lower-risk, higher probability projects, maintaining focus in south Louisiana and southeast Texas. In addition to the reduction in staff during the year, professional services decreased partially offset by an increase in insurance costs primarily for Company directors and officers. On an equivalent unit of production basis, general and administrative expenses were comparable for the two years.

Interest Expense.

Interest expense decreased $2.4 million to $11.5 million in 2003 compared to $13.9 million for 2002. The decrease was primarily a result of the reduction in long-term debt by $51.4 million and the Federal Reserve Bank's decrease in overall interest rates which led to a decrease in the average interest rate on the revolving credit facilities. The funds for the reduction in debt were the result of the August 2003 stock offering, improved cash flow from operations and the sale of certain non-strategic oil and gas properties.

Impairment of Long-Lived Assets.

In 2002, a write-down in oil and natural gas proved undeveloped reserves resulted in the Company recognizing a non-cash impairment of $69.1 million of its oil and natural gas properties under the full cost method of accounting. This was due to a negative revision associated with an unsuccessful well drilled in the Kent Bayou Field in 2002.

Credit Facility Retirement Costs.

During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a three-year $175 million underwritten senior secured 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 September 2002.

Taxes on Income.

The provision for income taxes for 2003 was $4.2 million. Income taxes were provided on book income after taking into account permanent differences between book income and taxable income, and after reducing the income tax valuation allowance by $2.7 million.

The income tax for 2002 was a credit of $22.0 million. This credit resulted from the 2002 book loss after taking into account permanent differences between book income and taxable income. This credit was limited to the amount of the Company's deferred tax liability at December 31, 2001.

Adoption of Statement of Financial Accounting Standards No. 143.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations." As a result, the Company recorded a long-term liability of $4.5 million representing the discounted present value of the estimated retirement obligations and an increase in capitalized oil and gas properties of $3.2 million. The liability will be accreted to its future value in subsequent reporting periods and will be charged to earnings on the Company's Consolidated Statement of Operations as "Accretion Expense." As a result of adoption of SFAS No. 143, the Company has charged approximately $0.7 million to earnings as accretion expense during 2003. The cumulative effect of the change in accounting principle for prior years totaled $1.3 million or $0.02 per share, and was charged to earnings in the first quarter of 2003.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS. Net cash flows provided by operating activities were $171.2 million for the year ended December 31, 2004, as compared to $91.6 million for the year ended December 31, 2003, an increase of $79.6 million or 87%. This increase was primarily attributable to a $65.3 million increase in revenue due to production and commodity price increases. The year-over-year change in operating assets and liability from December 31, 2003, to December 31, 2004, also accounted for approximately $12 million of increase in net cash flows provided by operating activities.

Net cash flows used in investing activities were $142.5 million for the year ended December 31, 2004, as compared to $67.0 million for the year ended December 31, 2003. The increase was due to an increase in capital expenditures of $70.5 million.

Net cash flows used in financing activities were $17.2 million for the year ended December 31, 2004, as compared to net cash flows used in financing activities of $19.1 million for 2003. During 2004, the Company retired $58.3 million in long-term debt and paid $5.2 million of preferred stock dividends, partially offset by the $45.8 million raised by selling common stock.

COMMON STOCK. In August 2004, the Company completed a public offering of 13,800,000 shares of Common Stock at a price of $7.25 per share. The total proceeds of the offering, net of issuance costs, received by the Company were approximately $94.6 million. The Company repurchased all of the 7,082,030 shares of its Common Stock that were beneficially owned by Shell Oil Company for $49.3 million and a portion of the remaining proceeds of that equity offering were used to repay borrowings under the Company's senior secured credit agreement, which resulted in an increase in funds available to the Company to accelerate planned capital expenditures for drilling activities and related pipeline construction. The repurchased 7,082,030 shares of Common Stock that were held in Treasury Stock were retired as of September 30, 2004.

In August 2003, the Company completed a private offering of 8,703,537 shares of Common Stock at a price of $3.87 per share. The total proceeds of the offering, net of issuance costs, received by the Company were approximately $33.0 million. The Company used the majority of these funds to retire $31.8 million in long-term debt, with the remainder of the proceeds being used for exploration activities and other general corporate purposes. As discussed below, during the nine months ended September 30, 2004, approximately 6.5 million shares of common Stock and approximately 4.2 million shares of Common stock were issued for the early conversion and retirement of the 9 1/2 % Convertible Subordinated Notes.

CURRENT CREDIT FACILITY. On December 23, 2004, the Company amended its existing credit facility to provide for a four-year $200 million senior secured credit facility (the "Credit Facility") with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia and Allied Irish Banks p.l.c. completed the syndication group. The initial borrowing base under the Credit Facility is $130 million. As of December 31, 2004, outstanding borrowings under the Credit Facility totaled $75.1 million.

The Credit Facility is subject to semi-annual borrowing base redeterminations on April 30 and October 31 of each year. In addition to the scheduled semi-annual borrowing base redeterminations, the lenders or the Company have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations.

Obligations under the Credit Facility are secured by pledges of outstanding capital stock of the Company's subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and gas properties. In addition, the Company is required to deliver to the lenders and maintain satisfactory title opinions covering not less than 70% of the present value of proved oil and gas properties. The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on Common Stock and under certain

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circumstances Preferred Stock, limitations on the redemption of Preferred Stock and an unqualified audit report on the Company's consolidated financial statements, with all of which the Company is in compliance.

Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 0.5% to 1.25% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base 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 2.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2004, the three-month LIBOR interest rate was 2.56%. The Credit Facility also provides for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans under the Credit Facility.

FORMER CREDIT FACILITY. During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a three-year $175 million underwritten senior secured credit agreement (the "Former Credit Agreement") with Societe Generale as administrative agent, lead arranger and book runner, and Fortis Capital Corporation, as co-lead arranger and documentation agent. Borrowings under the Former Credit Agreement were to mature on November 15, 2005, as extended by an amendment dated November 8, 2004. The amendment was subject to an extension fee of $450,000 to be paid in the event the Credit Facility had not been paid or refinanced by January 3, 2005.

The borrowing base was set at $127.5 million effective on October 31, 2004. Credit Facility payments of $48.3 million were made during the first nine months of 2004, bringing the outstanding balance to $74 million as of September 30, 2004. The Company made a final debt repayment of $74 million on December 23, 2004, which paid off in full this loan agreement.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders or borrower, under the Former Credit Agreement, had the right to redetermine the borrowing base at any time, once during each calendar year. Borrowings under the Former Credit Agreement were 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. On October 25, 2004, the Company notified Societe Generale that the present value of the mortgaged oil and gas properties total 86%. The Company received a waiver of the 90% test in anticipation of the new Fortis senior secured credit facility requiring only a 75% mortgage test. The Former Credit Agreement contained various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock and under certain circumstances Preferred Stock, and an unqualified audit report on the Company's consolidated financial statements.

Under the Former Credit Agreement, the Company could have secured either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate; or (b) federal funds-based rate plus 0.5%, 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; (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 Former Credit Agreement also provided 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 were unsecured and contained customary events of default, but did not contain any maintenance or other restrictive covenants. The interest rate was 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. At December 31, 2004, the three-month LIBOR rate was 2.56%. Note payments totaling $6.25 million were paid in 2002, with an additional $8.75 million paid in 2003. A note payment of $5 million was made during April 2004, with the remaining $5 million paid in December 2004.

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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 were unsecured and contained customary events of default, but did not contain any maintenance or other restrictive covenants. Interest was payable on a quarterly basis. The Company was in compliance with the financial covenants 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 were 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 was subject to customary anti-dilution provisions. The holders of the Notes were granted registration rights with respect to the shares of Common Stock that would be issued upon conversion of the Notes.

During March 2004, the notes were converted into 4.0 million shares of the Company's Common Stock at a conversion price of $5.00 per share, and included an additional non-cash conversion expense of approximately $1.2 million that was incurred and paid via the issuance of Common Stock priced at market. All of the Common Stock issued in connection with the conversion of the notes was issued under Section 4(2) of the Securities Act.

8.5% REDEEMABLE CONVERTIBLE PREFERRED STOCK. A private placement under Section 4(2) and Regulation D of the Securities Act 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 $4.45 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. 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. In the last quarter of 2003, $12.2 million of preferred stock was converted into 2.7 million shares of Common Stock.

In June 2004, the Company exercised its right, as described above, to convert one-third of its remaining issued and outstanding preferred stock into shares of Common Stock. The conversion was completed on a pro-rata basis and included a cash payment for accrued and unpaid dividends through the June 8, 2004, conversion date, at which time dividends ceased to accrue on the converted shares. During the year 2004, a total of $28.9 million of preferred stock was converted into 6.5 million shares of Common Stock.

CAPITAL EXPENDITURES. Capital expenditures in 2004 consisted of $142 million for property and equipment additions primarily related to exploration and development of various prospects, including leases, seismic data acquisitions, production facilities, and related 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 2005 capital expenditures plan is currently forecast at approximately $140 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 2005 plan primarily utilizing cash flow from operations. When appropriate, excess cash flow from operations beyond that needed for the 2005 capital expenditures plan will be used to de-lever the Company by development of exploration discoveries or direct payment of debt.

SALE OF PROPERTIES. During 2003, the Company sold certain non-strategic oil and gas properties located in south Louisiana for approximately $4.9 million. The sale was comprised of approximately 4 Bcfe proved developed reserves and 1 Bcfe of undeveloped reserves. Benefits of the sale include the reduction of total debt

by an additional $4.9 million resulting in an immediate savings in interest costs on the Company's senior bank debt, the elimination of $3.1 million in future capital expenditures associated with the properties, and the elimination of over $1.5 million in annual lease operating expenses.

CASH OBLIGATIONS. The following summarizes the Company's contractual obligations at December 31, 2004 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	TOTAL
Short and long term debt	$ 870	$ --	$75,129	$ 75,999
Interest	3,381	6,762	3,306	13,449
Dividends	2,685	5,370	3,356	11,411
Non-cancelable operating leases	2,537	1,847	25	4,409
Total contractual cash obligations	$9,473	$13,979	$81,816	$105,268

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.

For the year ended December 31, 2004, $3.5 million of dividends were accumulated (net of $0.4 million of deferred preferred stock offering costs amortized during 2004), of which $2.2 million was paid in cash in July 2004 and $1.3 million was paid in cash in January 2005. During 2003, dividends of $6.0 million were accumulated (net of $0.6 million of deferred preferred stock offering costs amortized during 2003), of which $3.0 million was satisfied with the issuance of additional shares of redeemable preferred stock and $3.0 million was paid in cash in January 2004. Dividends of $3.9 million were accumulated during 2002 (net of $0.4 million of deferred preferred stock offering costs amortized 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.

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 accepted in the United States of America. 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 to acquisition, exploration and development activities, and which are not related to production, general corporate overhead or similar activities. For the years 2004, 2003, and 2002, such capitalized costs totaled $11.9 million, $10.0 million, and $11.7 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, after deducting the asset retirement obligation, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, 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 are 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.

Due to the 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 cash flow 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. Cash flow hedge accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the earnings statements and requires 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 are recorded in other comprehensive income until earnings are affected by the variability in cash flows of the designated hedged item. Any changes in fair value resulting from the ineffectiveness of the hedge are reported in the consolidated statement of operations as a component of revenues. The Company recognized minimal losses related to hedge ineffectiveness during the two years ended December 31, 2003, and a gain of $126,000 during the year ended December 31, 2004.

During the year ended December 31, 2004, the change in estimated fair value of the Company's oil and natural gas swaps was an unrealized loss of $2.4 million ($1.6 million net of tax) which is recognized in other comprehensive income. Based upon December 31, 2004, oil and natural gas commodity prices, approximately $2.4 million of the loss deferred in other comprehensive income could potentially lower gross revenues in 2005. The swap agreements expire at various dates through October 31, 2005.

Net settlements under these swap agreements reduced oil and natural gas revenues by $18,624,000 and $14,916,000 and $1,183,000 for the years ended December 31, 2004, 2003, and 2002, respectively.

See Item 7.A., Quantitative and Qualitative Disclosures about Market Risk, 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, 2004 and 2003, 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 value of our subordinated notes due 2005 was $19.6 million at December 31, 2003. The carrying value of our subordinated notes was $20 million at December 31, 2003.

NEW ACCOUNTING PRONOUNCEMENTS. On September 28, 2004, the SEC released Staff Accounting Bulletin ("SAB") 106 regarding the application of SFAS 143, "Accounting for Asset Retirement Obligations ("AROs")," by oil and gas producing companies following the full cost accounting method. Pursuant to SAB 106, oil and gas producing companies that have adopted SFAS 143 should exclude the future cash outflows associated with settling AROs (ARO liabilities) from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized (ARO assets) should be included in the amortization base for computing depreciation, depletion and amortization expense. Disclosures are required to include discussion of how a company's ceiling test and depreciation, depletion and amortization calculations are impacted by the adoption of SFAS 143. SAB 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS 143 on

January 1, 2003, we have calculated the ceiling test and our depreciation, depletion and amortization expense in accordance with the interpretations set forth in SAB 106; therefore, the adoption of SAB 106 had no effect on our financial statements.

In December 2004, the FASB issued SFAS No. 123R which is a replacement statement to SFAS No. 123 entitled "Share-Based Payment." This statement also amends SFAS Statement 95. This statement addresses

the accounting for share-based payment transactions in which an enterprise receives employee services in exchange for (a) equity instruments of the enterprise or (b) liabilities that are based on the fair value of the enterprise's equity instruments or that may be settled by the issuance of such equity instruments. The statement would eliminate the ability to account for share-based compensation transactions using APB Opinion No. 25, "Accounting for Stock Issued to Employees," and generally would require instead that such transactions be accounted for using a fair-value-based method. This statement would be effective for interim periods beginning after June 15, 2005. The impact on the results of operations would be similar to the pro forma disclosures included in the notes to the financial statements.

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 may be 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 available data and of engineering and geological interpretation and judgment. Reserve estimates may be 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. 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 Fortis Capital Corp. is presently scheduled for borrowing base redetermination dates on a semi-annual basis, with the next such redetermination scheduled for April 30, 2005. 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. 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 $75.1 million remains borrowed under the Credit Facility, we estimate our annual interest expense will change by $0.75 million for each 100 basis point change in the applicable interest rates utilized under the Credit Facility.

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.

The Notional Amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 41% of our proved developed natural gas production and 38% of our proved developed oil production during the respective terms of the hedging agreements. 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.

The fair value of our hedging agreements is recorded on our consolidated balance sheet as assets or liabilities. The estimated fair value of our hedging agreements as of December 31, 2004, is provided below (see the Company's website at www.tmrc.com for a quarterly breakdown of the Company's hedge position for 2005 and beyond):

	Type	Notional Amount	Swap / Floor Price ($ per unit)	Ceiling Price ($ per unit)	Fair Value December 31, 2004 (in thousands)
NATURAL GAS (MMBTU)					
Jan 2005 - Jun 2005	Swap	910,000	$ 3.74	N/A	$(2,175)
Apr 2005 - Oct 2005	Swap	2,610,000	$ 6.34	N/A	492
Jan 2005 - Mar 2005	Collar	2,970,000	$ 7.00	$13.00	2,942
Apr 2005 - Oct 2005	Collar	2,600,000	$ 6.50	$ 7.90	1,751

Total Natural Gas					3,010
CRUDE OIL (BBLS)					
Jan 2005 - Jul 2005	Swap	266,000	$23.00	N/A	(5,308)
Total Crude Oil					(5,308)
					$(2,298)

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.

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

"Btu" means British Thermal Unit.

"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.

"MMBtu" means million Btus.

"MMcf" means million cubic feet.

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

"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%.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

Below is an index to the financial statements and notes contained in Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
The Meridian Resource Corporation

We have audited the accompanying consolidated balance sheets of The Meridian Resource Corporation and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income (loss) for the years then ended. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Meridian Resource Corporation and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

(BDO SEIDMAN, LLP)

Houston, Texas
March 10, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
The Meridian Resource Corporation

We have audited the accompanying consolidated statements of operations, stockholders' equity, and cash flows of The Meridian Resource Corporation and subsidiaries for the year 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 the standards of the Public Company Accounting Oversight Board (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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of The Meridian Resource Corporation and subsidiaries for the year ended December 31, 2002, in conformity with U.S. generally accepted accounting principles.

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 data)

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
REVENUES:			
Oil and natural gas	$202,447	$137,124	$106,992
Price risk management activities	126	--	--
Interest and other	545	355	478
	203,118	137,479	107,470
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	14,035	11,260	11,935
Severance and ad valorem taxes	9,394	7,608	8,235
Depletion and depreciation	102,915	75,441	60,972
General and administrative	15,169	11,610	11,820
Accretion expense	601	667	--
Write-down of securities held	195	--	--
Impairment of long-lived assets	--	--	69,124
	142,309	106,586	162,086
EARNINGS (LOSS) BEFORE OTHER EXPENSES & INCOME TAXES	60,809	30,893	(54,616)
OTHER EXPENSES:			
Interest expense	7,154	11,496	13,928
Debt conversion expense	1,188	--	--
Credit facility retirement costs	--	--	1,202
	8,342	11,496	15,130
EARNINGS (LOSS) BEFORE INCOME TAXES	52,467	19,397	(69,746)
INCOME TAXES:			
Current	834	(731)	298
Deferred	18,508	4,980	(22,300)
	19,342	4,249	(22,002)
EARNINGS (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	33,125	15,148	(47,744)
Cumulative effect of change in accounting principle	--	(1,309)	--
NET EARNINGS (LOSS)	33,125	13,839	(47,744)
Dividends on preferred stock	3,877	6,593	4,268
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ 29,248	$ 7,246	$(52,012)

NET EARNINGS (LOSS) PER SHARE BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE:			
Basic	$ 0.41	$ 0.16	$ (1.05)
Diluted	$ 0.37	$ 0.15	$ (1.05)
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE PER SHARE:			
Basic and Diluted	$ --	$ (0.02)	$ --
NET EARNINGS (LOSS) PER SHARE:			
Basic	$ 0.41	$ 0.14	$ (1.05)
Diluted	$ 0.37	$ 0.13	$ (1.05)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic	72,084	53,325	49,763
Diluted	79,033	57,144	49,763

See notes to consolidated financial statements.

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

	DECEMBER 31, 2004	DECEMBER 31, 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 24,297	$ 12,821
Restricted cash	891	--
Accounts receivable, less allowance for doubtful accounts $242 [2004] and $251 [2003]	27,763	24,703
Prepaid expenses and other	2,263	1,586
Assets from price risk management activities	5,705	584
Total current assets	60,919	39,694
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $34,731 [2004] and $30,542 [2003] not subject to depletion)	1,377,649	1,230,643
Land	478	478
Equipment	10,039	9,931
	1,388,166	1,241,052
Less accumulated depletion and depreciation	938,965	836,368
Total property and equipment, net	449,201	404,684
OTHER ASSETS	2,272	4,022
TOTAL ASSETS	$ 512,392	$ 448,400

See notes to consolidated financial statements.

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

	DECEMBER 31, 2004	DECEMBER 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 14,983	$ 8,692
Revenues and royalties payable	8,117	12,435
Due to affiliates	3,866	303
Notes payable	870	194
Accrued liabilities	21,406	12,074
Liabilities from price risk management activities	8,003	9,768
Asset retirement obligations	1,331	953
Current income taxes payable	105	415
Current portion long-term debt	--	10,000
Total current liabilities	58,681	54,834
LONG-TERM DEBT	75,129	122,320
9 1/2% CONVERTIBLE SUBORDINATED NOTES	--	20,000
OTHER:		
Deferred income taxes	22,639	931
Liabilities from price risk management activities	--	2,385
Asset retirement obligations	8,293	3,149
Other	20	--
	30,952	6,465
COMMITMENTS AND CONTINGENCIES (NOTES 6, 7 AND 11)	--	--
REDEEMABLE PREFERRED STOCK:		
Preferred stock, $1.00 par value (1,500,000 shares authorized, 315,886 [2004] and 604,460 [2003] shares of Series C Redeemable Convertible Preferred Stock issued at stated value)	31,589	60,446
STOCKHOLDERS' EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 79,215,394 [2004] and 61,724,597 [2003] issued)	821	644
Additional paid-in capital	490,351	394,177
Accumulated deficit	(173,244)	(202,492)
Accumulated other comprehensive loss	(1,574)	(7,704)
Unamortized deferred compensation	(313)	(290)
Total stockholders' equity	316,041	184,335

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 512,392	$ 448,400
	=========	=========

See notes to consolidated financial statements.

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

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings (loss)	$ 33,125	$ 13,839	$ (47,744)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	--	1,309	--
Depletion and depreciation	102,915	75,441	60,972
Amortization of other assets	1,506	1,715	2,057
Non-cash compensation	1,577	1,330	1,630
Non-cash price risk management activities	(126)	--	--
Credit facility retirement costs	--	--	1,202
Debt conversion expense	1,188	--	--
Write-down of securities held	195	--	--
Accretion expense	601	667	--
Impairment of long-lived assets	--	--	69,124
Deferred income taxes	18,508	4,980	(22,300)
Changes in assets and liabilities:			
Restricted cash	(891)	--	--
Accounts receivable	(3,060)	(536)	(58)
Due from affiliates	--	1,557	(713)
Prepaid expenses and other	(677)	635	(396)
Accounts payable	6,291	(8,150)	(19,110)
Due to affiliates	3,563	303	--
Revenues and royalties payable	(4,318)	57	2,582
Accrued liabilities and other	11,094	(1,525)	(4,723)
Net cash provided by operating activities	171,491	91,622	42,523
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(142,436)	(71,920)	(76,842)
Sale of property and equipment	(72)	4,893	(272)
Net cash used in investing activities	(142,508)	(67,027)	(77,114)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Redeemable preferred stock	--	--	66,850
Proceeds from long-term debt	75,129	--	165,000
Reductions in long-term debt	(132,320)	(51,430)	(196,250)
Proceeds - Notes payable	2,537	1,888	1,592
Reductions - Notes payable	(1,861)	(2,525)	(1,524)
Repurchase of common stock	(49,291)	--	--
Issuance of stock/exercise of stock options	94,777	33,185	307

Preferred dividends	(5,248)	--	(1,102)
Additions to deferred loan costs	(1,230)	(179)	(7,335)
Net cash provided by (used in) financing activities	(17,507)	(19,061)	27,538
NET CHANGE IN CASH AND CASH EQUIVALENTS	11,476	5,534	(7,053)
Cash and cash equivalents at beginning of year	12,821	7,287	14,340
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 24,297	$ 12,821	$ 7,287
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Non-cash financing activities:			
Conversion of preferred stock	$ (27,734)	$ --	$ --
Conversion of subordinated debt	$ (20,000)	$ --	$ --

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2002, 2003 AND 2004 (in thousands)

	Common Stock		Additional Paid-In Capital	Accumulated (Deficit)	Accumulated Other Comprehensiv Loss
	Shares	Par Value			
Balance, December 31, 2001	47,974	$553	$393,280	$(157,726)	$ (185)
Issuance of rights to common stock	--	4	1,596	--	--
Company's 401(k) plan contribution	172	--	(1,075)	--	--
Issuance of shares as compensation	1,941	--	(15,586)	--	--
Fractional share adjustments	2	--	--	--	--
Compensation expense	--	--	--	--	--
Accum. other comprehensive loss, net of taxes of $2,560	--	--	--	--	(4,753)
Preferred dividends	--	--	--	(4,268)	--
Net loss	--	--	--	(47,744)	--
Balance, December 31, 2002	50,089	557	378,215	(209,738)	(4,938)
Issuance of rights to common stock	--	8	1,256	--	--
Company's 401(k) plan contribution	109	--	(498)	--	--
Exercise of stock options	80	1	78	--	--
Compensation expense	--	--	--	--	--
Issuance of shares frm stock offering	8,704	50	3,456	--	--
Accum. other comprehensive income	--	--	--	--	(2,766)
Issuance for conversion of pref stock	2,743	28	11,670	--	--
Preferred dividends	--	--	--	(6,593)	--

Net earnings	--	--	--	13,839	--
Balance, December 31, 2003	61,725	644	394,177	(202,492)	(7,704)
Issuance of rights to common stock	--	3	1,597	--	--
Company's 401(k) plan contribution	52	--	343	--	--
Exercise of stock options	27	--	131	--	--
Compensation expense	--	--	--	--	--
Accum. other comprehensive income	--	--	--	--	5,945
Write-down of securities held	--	--	--	--	185
Issuance for conversion of pref stock	6,484	65	27,669	--	--
Issuance for conversion of sub debt	4,209	42	21,146	--	--
Issuance of shares frm stock offering	13,800	138	94,508	--	--
Repurchase of common stock	--	--	--	--	--
Retirement of treasury stock (09/04)	(7,082)	(71)	(49,220)	--	--
Preferred dividends	--	--	--	(3,877)	--
Net earnings	--	--	--	33,125	--
Balance, December 31, 2004	79,215	$821	$490,351	$(173,244)	$(1,574)

	Unamortized Deferred Compensation	Treasury Stock Shares	Treasury Stock Cost	Total
Balance, December 31, 2001	$ (386)	5,892	$(47,315)	$188,221
Issuance of rights to common stock	(1,600)	--	--	--
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	--	--	1,630
Accum. other comprehensive loss, net of taxes of $2,560	--	--	--	(4,753)
Preferred dividends	--	--	--	(4,268)
Net loss	--	--	--	(47,744)
Balance, December 31, 2002	(356)	3,779	(30,347)	133,393
Issuance of rights to common stock	(1,264)	--	--	--
Company's 401(k) plan contribution	--	(93)	747	249
Exercise of stock options	--	(22)	177	256
Compensation expense	1,330	--	--	1,330
Issuance of shares frm stock offering	--	(3,664)	29,423	32,929
Accum. other comprehensive income	--	--	--	(2,766)
Issuance for conversion of pref stock	--	--	--	11,698
Preferred dividends	--	--	--	(6,593)

Net earnings	--	--	--	13,839
Balance, December 31, 2003	(290)	--	--	184,335
Issuance of rights to common stock	(1,600)	--	--	--
Company's 401(k) plan contribution	--	--	--	343
Exercise of stock options	--	--	--	131
Compensation expense	1,577	--	--	1,577
Accum. other comprehensive income	--	--	--	5,945
Write-down of securities held	--	--	--	185
Issuance for conversion of pref stock	--	--	--	27,734
Issuance for conversion of sub debt	--	--	--	21,188
Issuance of shares frm stock offering	--	--	--	94,646
Repurchase of common stock	--	(7,082)	(49,291)	(49,291)
Retirement of treasury stock (09/04)	--	7,082	49,291	--
Preferred dividends	--	--	--	(3,877)
Net earnings	--	--	--	33,125
Balance, December 31, 2004	$ (313)	--	$ --	$316,041

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(thousands of dollars)

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Net earnings (loss) applicable to common stockholders	$29,248	$ 7,246	$(52,012)
Other comprehensive income (loss), net of tax, for unrealized losses from hedging activities:			
Unrealized holding losses arising during period	(6,161)	(12,461)	(5,522)
Reclassification adjustments on settlement of contracts	12,106	9,695	769
Write-down of securities held	185	--	--
	6,130	(2,766)	(4,753)
Total comprehensive income (loss)	$35,378	$ 4,480	$(56,765)

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 Texas corporation.

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.

RESTRICTED CASH

The Company classifies cash balances as restricted cash when cash is restricted as to withdrawal or usage. The restricted cash balance at December 31, 2004, was $891,000, and at December 31, 2003, was $0. The restricted cash is related to a contractual obligation related to royalties payable.

PROPERTY AND EQUIPMENT

The Company follows the full cost method of accounting for its investments in oil and natural gas properties. All costs incurred in 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, reduced by the asset retirement obligation, 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 as adjusted for the Company's cash flow hedge positions, plus the lower of cost or estimated fair market value of unproved properties adjusted for related income tax effects.

Capitalized costs of proved oil and natural gas properties are depleted on a units 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.

STATEMENT OF CASH FLOWS

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 $6.3 million, $9.6 million and $11.7 million in 2004, 2003 and 2002, respectively. Cash payments for income taxes (federal and state, net of receipts) were $950,000 for 2004, $23,000 for 2003, and none for 2002.

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.

The Company maintains its cash in bank deposit accounts which, at times, may exceed federally insured limits. Accounts are guaranteed by the Federal Deposit Insurance Corporation (FDIC) up to $100,000. At December 31, 2004, and December 31, 2003, the Company had approximately $22,970,000 and $12,360,000, respectively, in excess of FDIC insured limits. The Company has not experienced any losses in such accounts.

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.

SFAS 123, "Accounting for Stock-Based Compensation," as amended by SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As provided for under SFAS 123, there has been no amount of compensation expense recognized for the Company's stock option plans. The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting

Principles Board Opinion 25, "Accounting for Stock Issued to Employees." Compensation expense is recorded for restricted stock awards over the requisite vesting periods based upon the market value on the date of the grant. No stock-based compensation expense was recorded in the years ended December 31, 2004, 2003 or 2002.

The following is a reconciliation of reported earnings (loss) and earnings (loss) per share as if the Company used the fair value method of accounting for stock-based compensation (thousands of dollars, except per share information):

	2004	2003	2002
Net earnings (loss) applicable to common stockholders as reported	$29,248	$7,246	$(52,012)
Stock-based compensation (expense) benefit determined under fair value method for all awards, net of tax	(119)	63	(39)
Net earnings (loss) applicable to common stockholders pro forma	$29,129	$7,309	$(52,051)
Basic earnings (loss) per share:			
As reported	$ 0.41	$ 0.14	$ (1.05)
Pro forma	$ 0.40	$ 0.14	$ (1.05)
Diluted earnings (loss) per share:			
As reported	$ 0.37	$ 0.13	$ (1.05)
Pro forma	$ 0.37	$ 0.13	$ (1.05)

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 3.37%, 2.87% and 2.54%; dividend yield of 0%; volatility factors of the expected market price of the Company's Common Stock of 0.96, 1.02 and 0.81 for 2004, 2003 and 2002, respectively; and a weighted-average expected life of five years. These assumptions resulted in a weighted average grant date fair value of $5.92, $3.44 and $1.97 for options granted in 2004, 2003 and 2002, 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.

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, 2004 and 2003, 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 value of our subordinated notes was $19.6 million at December 31, 2003. The carrying value of our subordinated notes was $20 million at December 31, 2003.

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 derivative 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 recognized minimal losses related to hedge ineffectiveness during the two years ended December 31, 2003, and a gain of $126,000 during the year ended December 31, 2004.

The Company discontinues cash flow 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 cash flow 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 SFAS 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 PRONOUNCEMENTS

On September 28, 2004, the Securities and Exchange Commission released Staff Accounting Bulletin ("SAB") 106 regarding the application of SFAS 143, "Accounting for Asset Retirement Obligation ("AROs")," by oil and gas producing companies following the full cost accounting method. Pursuant to SAB 106, oil and gas producing companies that have adopted SFAS 143 should exclude the future cash outflows associated with settling AROs (ARO liabilities) from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized (ARO assets) should be included in the amortization base for computing depreciation, depletion and amortization expense. Disclosures are required to include discussion of how a company's ceiling test and depreciation, depletion and amortization calculations are impacted by the adoption of SFAS 143. SAB 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS 143 on January 1, 2003, we have calculated the ceiling test and our depreciation, depletion and amortization expense in accordance with the interpretations set forth in SAB 106; therefore, the adoption of SAB 106 had no effect on our financial statements.

In December 2004, the FASB issued SFAS No. 123R which is a replacement statement to SFAS No. 123 entitled "Share-Based Payment." This statement also amends SFAS Statement 95. This statement addresses the accounting for share-based payment transactions in which an enterprise receives employee services in exchange for

(a) equity instruments of the enterprise or (b) liabilities that are based on the fair value of the enterprise's equity instruments or that may be settled by the issuance of such equity instruments. The statement would eliminate the ability to account for share-based compensation transactions using APB Opinion No. 25, "Accounting for Stock Issued to Employees," and generally would require instead that such transactions be accounted for using a fair-value-based method. This statement would be effective for the Company for interim periods beginning after June 15, 2005. The impact on the results of operations would be similar to the pro forma disclosures made above.

USE OF ESTIMATES

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America 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, 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. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations." This 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. The fair value of asset retirement obligation liabilities has been calculated using an expected present value technique. Fair value, to the extent possible, should include a market risk premium for unforeseeable circumstances. No market risk premium was included in the Company's asset retirement obligations fair value estimate since a reasonable estimate could not be made. 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 amortized 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 requires the Company to record a liability for the fair value of the dismantlement and abandonment costs, excluding salvage values.

Upon adoption, the Company recorded transition amounts for liabilities related to its wells, and the associated costs to be capitalized. A liability of $4.5 million was recorded to long-term liabilities and a net asset of $3.2 million was recorded to oil and natural gas properties on January 1, 2003. This resulted in a cumulative effect of an accounting change of ($1.3) million. Accretion expenses subsequent to the adoption of this accounting statement decreased net earnings $601 thousand and $667 thousand in 2004 and 2003, respectively.

The pro forma effects of the application of SFAS 143, as if the statement had been adopted on January 1, 2001, is presented below (thousands of dollars except per share information):

	2004	2003	2002
Net earnings (loss) applicable to common stockholders	$29,248	$7,246	$(52,012)
Additional accretion expense	--	--	(470)
Cumulative effect of accounting change	--	1,309	--
Pro forma net earnings (loss) applicable to common stockholders	$29,248	$8,555	$(52,482)
Pro forma earnings (loss) per share:			
Basic	$ 0.41	$ 0.16	$ (1.05)
Diluted	$ 0.37	$ 0.15	$ (1.05)

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The following table describes the change in the Company's asset retirement obligations for the years ended December 31, 2004 and 2003 (thousands of dollars):

Asset retirement obligation at December 31, 2002	$ 4,523
Additional retirement obligations recorded in 2003	338
Reduction due to property sale in 2003	(1,010)
Other revisions during 2003	(416)
Accretion expense for 2003	667
Asset retirement obligation at December 31, 2003	4,102
Additional retirement obligations recorded in 2004	1,051
Settlements during 2004	(972)
Revisions to estimates during 2004	4,842
Accretion expense for 2004	601
Asset retirement obligation at December 31, 2004	$ 9,624

Our revisions to estimates represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and costs to do so.

4. IMPAIRMENT OF LONG-LIVED ASSETS

In the third quarter of 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 a full cost ceiling write-down of oil and natural gas properties totaling $69.1 million.

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.

5. DEBT

CURRENT REVOLVING CREDIT AGREEMENT

On December 23, 2004, the Company amended its existing credit facility to provide for a four-year $200 million senior secured credit facility (the "Credit Facility") with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia and Allied Irish Banks p.l.c. completed the syndication group. The initial borrowing base under the Credit Facility is $130 million. As of December 31, 2004, outstanding borrowings under the Credit Facility totaled $75.1 million.

The Credit Facility is subject to semi-annual borrowing base redeterminations on April 30 and October 31 of each year. In addition to the scheduled semi-annual borrowing base redeterminations, the lenders or the Company, have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations.

Obligations under the Credit Facility are secured by pledges of outstanding capital stock of the Company's subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and gas properties. In addition, the Company is required to deliver to the lenders

and maintain satisfactory title opinions covering not less than 70% of the present value of proved oil and gas properties. The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on Common Stock and under certain circumstances Preferred Stock, limitations on the redemption of Preferred Stock and an unqualified audit report on the Company's consolidated financial statements, all of which the Company is in compliance.

Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 0.5% to 1.25% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base 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 2.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2004, the three-month LIBOR interest rate was 2.56%. The Credit Facility also provides for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans under the Credit Facility.

FORMER REVOLVING CREDIT AGREEMENT

During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a three-year $175 million underwritten senior secured credit agreement (the "Former Credit Agreement") with Societe Generale as administrative agent, lead arranger and book runner, and Fortis Capital Corporation, as co-lead arranger and documentation agent. Borrowings under the Former Credit Agreement were to mature on November 15, 2005, as extended by an amendment dated November 8, 2004. The amendment was subject to an extension fee of $450,000 to be paid in the event the Credit Facility has not been paid or refinanced by January 3, 2005.

The borrowing base was set at $127.5 million effective on October 31, 2004. Credit Facility payments of $48.3 million were made during the first nine months of 2004, bringing the outstanding balance to $74 million as of September 30, 2004. The Company made a final debt repayment of $74 million on December 23, 2004, which paid off in full this loan agreement.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders or borrower, under the Former Credit Agreement, had the right to redetermine the borrowing base at any time, once during each calendar year. Borrowings under the Former 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. On October 25, 2004, the Company notified Societe Generale that the present value of the mortgaged oil and gas properties totaled 86%. The Company received a waiver of the 90% test in anticipation of the new Fortis senior secured credit facility requiring only a 75% mortgage test. The Former Credit Agreement contained various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock and under certain circumstances Preferred Stock, and an unqualified audit report on the Company's consolidated financial statements.

Under the Former Credit Agreement, the Company could have secured either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate; or (b) federal funds-based rate plus 0.5%, 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; (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 Former Credit Agreement also provided 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 were unsecured and contained customary events of default, but did not contain any maintenance or other restrictive covenants. The interest rate was 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. At December 31, 2004, the three-month LIBOR rate was 2.56%. Note payments totaling $6.25 million were paid in 2002, with an additional $8.75 million paid in 2003. A note payment of $5 million was made during April 2004, with the remaining $5 million paid in December 2004.

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 were unsecured and contained customary events of default, but did not contain any maintenance or other restrictive covenants. Interest was payable on a quarterly basis. The Company was in compliance with the financial covenants 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 were 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 was subject to customary anti-dilution provisions. The holders of the Notes were granted registration rights with respect to the shares of Common Stock that would be issued upon conversion of the Notes.

During March 2004, the notes were converted into 4.0 million shares of the Company's Common Stock at a conversion price of $5.00 per share, and included an additional non-cash conversion expense of approximately $1.2 million that was incurred via the issuance of Common Stock priced at market.

CURRENT DEBT MATURITIES

Scheduled debt maturities for the next five years and thereafter, as of December 31, 2004, are as follows: none in 2005, 2006, or 2007, $75.1 million in 2008, and none thereafter.

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 $2.4 million, $2.3 million and $2.2 million in 2004, 2003 and 2002, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $2.5 million for 2005, $1.8 million for 2006, $0.1 million for 2007 and none thereafter.

7. COMMITMENTS AND CONTINGENCIES

LITIGATION

PETROQUEST LITIGATION. This litigation was settled in December 2003 and all claims were dismissed. In December 1999, PetroQuest Energy, Inc. (formerly known as Optima Energy (U.S.) Corporation) ("PetroQuest") filed a claim against Meridian for damages "estimate[d] to exceed several million dollars" alleging that Meridian was liable for gross negligence and willful misconduct in the execution of certain agreements related to property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish, Louisiana and for an alleged withholding of funds totaling $886,153.31, in conjunction with Meridian's having paid a prior adverse judgment in favor of Amoco Production Company. Meridian filed an answer denying PetroQuest's claims and asserted a counterclaim for attorney's fees, court costs and other expenses and for declaratory relief that Meridian is entitled to retain the amounts (with all interest thereon) that it had suspended from disbursement to PetroQuest. Under the confidential settlement agreement, Meridian agreed to make two

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payments which have now been made. The settlement amount was fully reflected in the financial statements at December 31, 2003. Judgments of dismissal were signed in January 2004.

RAMOS TITLE LITIGATION. This litigation was settled in March 2004 and all claims were dismissed. Three different groups asserted adverse title claims to some or all of Section 80 (640 acres) within Meridian's Thibodaux units in the Ramos Field. Another entity asserted adverse title claims to a portion of Section 36 within these same units. These claims turned primarily on the location of the parish boundary lines between Terrebonne and Assumption Parishes and/or the validity of various tax sales in the chain of title. Meridian's gas purchaser, Louisiana Intrastate Gas Company LLC ("LIG"), deposited into the Terrebonne Parish court registry certain gas and plant-product proceeds attributable to 25 acres within these units since October 2000, and Meridian suspended payment of royalties and working interest attributable to these same 25 acres since December 2000. Meridian and its partners and royalty owners reached an agreement whereby the parties' plaintiff granted a lease on all of the disputed acreage to the current interest owners for a lease bonus of $4.5 million and a future royalty interest of 1.5%.

H. L. HAWKINS LITIGATION. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages "estimated to exceed several million dollars" for Meridian's alleged gross negligence and willful misconduct under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish, as a result of Meridian's satisfying a prior adverse judgment in favor of Amoco Production Company. Meridian will file an answer denying Hawkins' claims and assert a counterclaim for attorney's fees, court costs and other expenses, and for declaratory relief that Meridian is entitled to retain the amounts that it had been paid by Hawkins. The Company has not provided any amount for this month in its financial statements at December 31, 2004.

ENVIRONMENTAL LITIGATION. Various landowners have sued Meridian (along with numerous other oil companies) in various similar lawsuits concerning the Weeks Island, Gibson, Bayou Pigeon, West Lake Verret and White Castle Fields. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs' lands from alleged contamination and otherwise from the defendants' oil and gas operations.

There are no other material legal proceedings which exceed our insurance limits to which the Company or any of its subsidiaries 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.

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8. TAXES ON INCOME

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

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Current:			
Federal	$ 905	$ (568)	$ 327
State	(71)	(163)	(29)
Deferred:			
Federal	18,160	4,980	(22,300)
State	348	--	--
Income tax expense (benefit)	$19,342	$4,249	$(22,002)

The 2004 provision for Federal income taxes currently payable is the result of alternative minimum tax.

The Company's income tax provision is attributed to the following items:

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Earnings (loss) before cumulative effect of change in accounting principle	$19,342	$ 4,249	$(22,002)
Losses on derivatives recognized in other comprehensive income (loss)	3,199	(1,489)	(2,560)
Total income tax provision	$22,541	$ 2,760	$(24,562)

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

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Income tax provision (benefit) computed at statutory rate	$18,364	$ 6,331	$(24,525)
Nondeductible costs	607	758	308
State income tax, net of federal tax benefit	302	(106)	(19)
Decrease in net operating loss carryover due to expiration	69	--	--
Change in valuation allowance	--	(2,734)	2,234
Income tax expense (benefit)	$19,342	$ 4,249	$(22,002)

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):

	DECEMBER 31,	
	2004	2003
Deferred tax assets:		
Net operating tax loss carryforward	$ 41,244	$39,208
Statutory depletion carryforward	950	950

Tax credits	1,987	1,083
Unrealized hedge loss	850	4,049
Other	4,698	4,631
Total deferred tax assets	49,729	49,921
Deferred tax liabilities:		
Book in excess of tax basis in oil and gas properties	72,298	50,782
Basis differential in long-term investments	70	70
Total deferred tax liabilities	72,368	50,852
Net deferred tax asset (liability)	$(22,639)	$ (931)

As of December 31, 2004, the Company has approximately $117.8 million of tax net operating loss carryforwards. 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.

The net operating loss carryforwards begin to expire in 2006 and extend through 2023. A portion of the net operating loss carryforwards is subject to change in ownership and separate return limitations that could restrict the Company's ability to utilize such losses in the future.

As of December 31, 2004, the Company had net operating loss carryforwards for regular tax and alternative minimum taxable income (AMT) purposes available to reduce future taxable income. These carryforwards expire as follows (in thousands of dollars):

YEAR OF EXPIRATION	NET OPERATING LOSS	AMT OPERATING LOSS
2006	$ 699	$ 699
2018	11,621	--
2019	47,730	44,404
2020	31	31
2021	36	36
2022	13,053	13,786
2023	44,669	44,516
TOTAL	$117,839	$103,472

As of December 31, 2004, the Company had approximately $1,987,415 of alternative minimum tax (credit) carryover that does not expire.

Generally Accepted Accounting Principles require 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. The Company expects to fully utilize its net operating loss carryforward tax benefits, and therefore did not record a valuation allowance in 2004.

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 $4.45 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. 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. In the last quarter of 2003, $12.2 million of preferred stock was converted into 2.7 million shares of Common Stock.

In June 2004, the Company exercised its right, as described above, to convert one-third of its remaining issued and outstanding preferred stock into shares of Common Stock. The conversion was completed on a pro-rata basis and included a cash payment for accrued and unpaid dividends through the June 8, 2004, conversion date, at which time dividends ceased to accrue on the converted shares. During the year 2004, a total of $28.9 million of preferred stock was converted into 6.5 million shares of Common Stock. No gain or loss was recorded as a result of the conversion.

For the year ended December 31, 2004, $3.5 million of dividends were accumulated (net of $0.4 million of deferred preferred stock offering costs amortized during 2004), of which $2.2 million was paid in cash in July 2004 and $1.3 million was paid in cash in January 2005. During 2003, dividends of $6.0 million were accumulated (net of $0.6 million of deferred preferred stock offering costs amortized during 2003), of which $3.0 million was satisfied with the issuance of additional shares of redeemable preferred stock and $3.0 million was paid in cash in January 2004. Dividends of $3.9 million were accumulated during 2002 (net of $0.4 million of deferred preferred stock offering costs amortized 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

In August 2004, the Company completed a public offering of 13,800,000 shares of Common Stock at a price of $7.25 per share. The total proceeds of the offering, net of issuance costs, received by the Company were approximately $94.6 million. The Company repurchased all of the 7,082,030 shares of its Common Stock that were beneficially owned by Shell Oil Company for $49.3 million and a portion of the remaining proceeds of that equity offering was used to repay borrowings under the Company's senior secured credit agreement, which resulted in an increase in funds available to the Company to accelerate planned capital expenditures for drilling activities and related pipeline construction. The repurchased 7,082,030 shares of Common Stock that were held in Treasury Stock were retired as of September 30, 2004.

In August 2003, the Company completed a private offering of 8,703,537 shares of common stock at a price of $3.87 per share. The total proceeds of the offering, net of issuance costs, received by the Company were approximately $33.0 million. The Company used the majority of these funds to retire $31.8 million in long-term debt, and the remainder of the proceeds is being used for exploration activities and for other general corporate purposes.

WARRANTS

The Company had the following warrants outstanding at December 31, 2004:

WARRANTS	NUMBER OF SHARES	EXERCISE PRICE	EXPIRATION DATE
Executive Officers	1,428,000	$5.85	*
General Partner	1,604,428	$0.12	December 31, 2015

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

As of December 31, 2004, the Company had outstanding (i) warrants (the "General Partner Warrants") that entitle Joseph A. Reeves, Jr. and Michael J. Mayell to purchase an aggregate of 1,604,428 shares of Common Stock at an exercise price of $0.12 per share through December 31, 2015 and (ii) executive officer warrants that entitle each of Joseph A. Reeves, Jr. and Michael J. Mayell to purchase an aggregate of 714,000 shares of Common Stock at an exercise price of $5.85 for a period until one year following the date on which the respective individual ceases to be an employee of the Company ("Executive Officer Warrants").

The number of shares of Common Stock purchasable upon the exercise of each warrant described above and its corresponding exercise price are subject to customary anti-dilution adjustments. In addition to such customary adjustments, the number of shares of Common Stock and exercise price per share of the General Partner Warrants are subject to adjustment for any issuance of Common Stock by the Company such that each warrant will permit the holder to purchase at the same aggregate exercise price, a number of shares of Common Stock equal to the percentage of outstanding shares of the Common Stock that the holder could purchase before the issuance. Currently each of these warrants permits the holder to purchase approximately 1% of the outstanding shares of the Common Stock for an aggregate exercise price of $94,303. The General Partner Warrants were issued to Messrs. Reeves and Mayell in conjunction with certain transactions with Messrs. Reeves and Mayell that took place in anticipation of the Company's consolidation in December 1990 and were a component of the total consideration issued for various interests that Messrs. Reeves and Mayell had as general partners in TMR, Ltd., a predecessor entity 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.

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, 2004, 2003 and 2002, 1,670,685, 2,130,334, and 445,765 shares, respectively, were available for grant under the plans. A summary of option transactions follows:

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at December 31, 2001	4,159,575	$4.56
Granted	15,000	3.00
Exercised	--	--
Canceled	(10,500)	5.22
Outstanding at December 31, 2002	4,164,075	$4.55
Granted	15,000	4.51
Exercised	(80,000)	3.19
Canceled	(540,250)	7.87
Outstanding at December 31, 2003	3,558,825	$4.08
Granted	173,750	7.94
Exercised	(34,875)	4.49
Canceled	(4,650)	5.78
Outstanding at December 31, 2004	3,693,050	$4.25
Shares exercisable:		
December 31, 2002	4,089,450	$4.53
December 31, 2003	3,510,700	$4.06
December 31, 2004	3,498,050	$4.06

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
RANGE OF EXERCISABLE PRICES	OUTSTANDING AT DECEMBER 31, 2004	WEIGHTED AVERAGE EXERCISE PRICE	EXERCISABLE AT DECEMBER 31, 2004	WEIGHTED AVERAGE EXERCISE PRICE
$3.00 - $4.75	3,126,150	$ 3.38	3,111,150	$ 3.38
$5.45 - $9.00	368,250	8.10	188,250	8.25
$10.38 - $11.13	198,650	10.84	198,650	10.84
	3,693,050	$ 4.25	3,498,050	$ 4.06

The weighted average remaining contractual life of options outstanding at December 31, 2004, was approximately four 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 2004, $316,000 for 2003 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. For 1997, the price was determined at December 31, 1996, and for all years subsequent to 1997, it was determined on a semi-annual basis at December 31st and June 30th. At December 31, 2004, the plan had reserved 3,600,000 shares of Common Stock for future issuance and 2,931,308 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 $1,577,000, $1,330,000 and $1,630,000 for 2004, 2003 and 2002 periods, respectively, and is reflected in general and administrative expense and in oil and gas properties for the years ended December 31, 2004, 2003 and 2002, 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 percent interest in a share of the Company's Series B Junior Participating 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 Company's 401(k) plan was $299,000, $331,000 and $306,000 in 2004, 2003, and 2002, 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 $6.9 million, $4.3 million and $4.2 million in 2004, 2003 and 2002, 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 nor Mayell participate in the Management Plan. The participants in the Trust Plan generally will be 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.

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, 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. 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 natural 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 hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, these 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 are recorded in other comprehensive income until earnings are affected by the variability in cash flows of the designated hedged item. Any changes in fair value resulting from the ineffectiveness of the hedge are reported in the consolidated statement of operations as a component of revenues. The Company recognized minimal losses related to hedge ineffectiveness during the two years ended December 31, 2003, and a gain of $126,000 during the year ended December 31, 2004.

For the year ended December 31, 2004, the change in estimated fair value of the Company's oil and natural gas swaps was an unrealized loss of $2.4 million ($1.6 million net of tax) which is recognized in other comprehensive income. Based upon December 31, 2004, oil and natural gas commodity prices approximately $2.4 million of the loss deferred in other comprehensive income could potentially lower gross revenues in 2005. These swap agreements expire at various dates through October 31, 2005.

Net settlements under these swap agreements reduced oil and natural gas revenues by $18,624,000, $14,916,000 and $1,183,000 for the years ended December 31, 2004, 2003, and 2002 respectively, as a result of hedging transactions.

The Notional Amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 41% of our proved developed natural gas production and 38% of our proved developed oil production during the respective terms of the hedging agreements. 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.

The fair value of our hedging agreements is recorded on our consolidated balance sheet as assets or liabilities. The estimated fair value of our hedging agreements as of December 31, 2004, is provided below:

	Type	Notional Amount	Swap / Floor Price ($ per unit)	Ceiling Price ($ per unit)	Fair Value December 31, 2004 (in thousands)
NATURAL GAS (MMBTU)					
Jan 2005 - Jun 2005	Swap	910,000	$ 3.74	N/A	$(2,175)
Apr 2005 - Oct 2005	Swap	2,610,000	$ 6.34	N/A	492
Jan 2005 - Mar 2005	Collar	2,970,000	$ 7.00	$13.00	2,942
Apr 2005 - Oct 2005	Collar	2,600,000	$ 6.50	$ 7.90	1,751
Total Natural Gas					3,010
CRUDE OIL (BBLS)					
Jan 2005 - Jul 2005	Swap	266,000	$23.00	N/A	(5,308)
Total Crude Oil					(5,308)
					$(2,298)

See Note 17, Subsequent Events, for additional information.

13. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2004, 2003 and 2002, were as follows (based on purchases exceeding 10% of oil and natural gas as a percent of total oil and natural gas sales):

CUSTOMER	2004	2003	2002
	YEAR ENDED DECEMBER 31,		
Superior Natural Gas	45%	19%	--

Louisiana Intrastate Gas	22%	24%	17%
Conoco, Inc.	--	10%	12%
Equiva Trading Company(1) ...	--	--	33%

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

14. 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"), JAR Resources LLC ("JAR") 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% to 4% 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, JAR and Sydson invested $8,539,000, $5,161,000 and $3,289,000 for the years ended December 31, 2004, 2003 and 2002, respectively, in oil and natural gas drilling activities for which the Company was the operator. Net amounts due to TODD and Mr. Reeves were approximately $1,751,000 and $321,000 as of December 31, 2004 and 2003, respectively. Net amounts due to/(from) Sydson and Mr. Mayell were approximately $2,115,000 and ($18,000) as of December 31, 2004 and 2003, 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, 2004, 2003 and 2002 and received fees of approximately $255,000, $210,000 and $282,000, 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. Kares also participated in the Management Plan described in Note 11 above, pursuant to which he was paid approximately $298,000 during 2004 and $61,000 during 2003.

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, 2004, 2003 and 2002, and received fees of approximately $12,000, $49,000 and $27,000, respectively. 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. 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 11 above, pursuant to which he was paid approximately $688,000 during 2004, $360,000 during 2003 and $377,000 during 2002.

Mr. Joseph A. Reeves, Jr., an officer and Director of Meridian, has two relatives currently employed by the Company. J.Drew Reeves, his son, is a staff member in the Finance Department. He has a Masters degree in Business Administration from Louisiana State University and was employed as a Landman for the firm of Land Management LLC in Metairie, Louisiana, prior to joining Meridian in 2003. Mr. Drew Reeves was paid $80,000 and $40,000 for the years 2004 and 2003, respectively. Jeff Robinson is the son-in-law of Joseph A. Reeves, Jr. and is employed as the Manager of the Company's Information Technology Department and has been paid $101,000 and $42,000 for the years 2004 and 2003, respectively. Mr. Robinson earned his undergraduate degree in MIS from

Auburn University and was employed by BSI Consulting for 5 years prior to joining Meridian in 2003. J. Todd Reeves, a partner in the law firm of Creighton, Richards, Higdon and Reeves in Covington, Louisiana, is the son of Joseph A. Reeves, Jr. This law firm provided legal services for the Company for the year ended December 31, 2004, and received fees of approximately $67,000. Such fees exceeded 5% of the gross revenues for this firm for 2004. 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.

James T. Bond, former Director of Meridian, is the father-in-law of Michael J. Mayell, an officer and Director of Meridian, and has provided consultant services to the Company and received fees in the amount of $124,000, $115,000, and $48,000, for the years 2004, 2003 and 2002, respectively.

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15. EARNINGS PER SHARE

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

	(in thousands, except per share) YEAR ENDED DECEMBER 31,		
	2004	2003	2002(1)
Numerator:			
Net earnings (loss) applicable to common stockholders	$29,248	$ 7,246	$(52,012)
Plus income impact of assumed conversions:			
Preferred stock dividends	N/A	N/A	N/A
Interest on convertible subordinated notes	270	N/A	N/A
Net earnings (loss) applicable to common stockholders plus assumed conversions	$29,518	$ 7,246	$(52,012)
Denominator:			
Denominator for basic earnings per share - weighted-average shares outstanding	72,084	53,325	49,763
Effect of potentially dilutive common shares:			
Warrants	4,508	3,393	N/A
Employee and director stock options	1,589	426	N/A
Convertible subordinated notes	852	N/A	N/A
Redeemable preferred stock	N/A	N/A	N/A
Denominator for diluted earnings per share - weighted-average shares outstanding and assumed conversions	79,033	57,144	49,763
Basic earnings (loss) per share	$ 0.41	$ 0.14	$ (1.05)
Diluted earnings (loss) per share	$ 0.37	$ 0.13	$ (1.05)

(1) Anti-dilutive in 2002.

N/A = Not Applicable, meaning anti-dilutive for periods present. Due to its anti-dilutive effect on earnings per share, approximately 9.8 million shares in

2004, 22.7 million shares in 2003, and 27.7 million shares in 2002, related to our redeemable preferred stock, convertible subordinated notes, stock options and warrants were excluded from the dilutive shares.

16. ACCRUED LIABILITIES

Below is the detail of our accrued liabilities on our balance sheets as of December 31:

	2004	2003
Capital expenditures	$12,662	$ 3,508
Bonuses	3,355	1,715
Dividends	1,346	3,057
Other	4,043	3,794
TOTAL	$21,406	$12,074

17. SUBSEQUENT EVENT

During January 2005, the Company entered into a series of hedging contracts to hedge a portion of its expected oil production for 2005 and 2006. The hedge contracts were completed in the form of costless collars. The costless collars provide the Company with a lower floor price and an upper limit ceiling price on the hedged volumes. The floor price represents the lowest price the Company will receive for the hedged volumes while the ceiling price represents the highest price the Company will receive for the hedged volumes. The costless collars will be settled monthly based on the daily settlement price of the NYMEX futures contract of oil during each respective month. The following table summarizes the contracted volumes and price for the costless collars.

Production Month	Contracted Volume (Bbl)	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
August 2005 - July 2006	209,000	$37.50	$47.50
August 2005 - July 2006	48,000	$40.00	$50.00

18. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Results of operations by quarter for the year ended December 31, 2004 were (thousands of dollars, except per share):

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31

2004				
Revenues	$46,192	$50,103	$53,037	$53,786
Results of operations from exploration and production activities(1)	17,229	19,545	19,428	20,272
Net earnings (loss)(2)	$ 5,287	$ 7,745	$ 7,786	$ 8,430
Net earnings (loss) per share:(2)				
Basic	$ 0.08	$ 0.11	$ 0.10	$ 0.11
Diluted	0.08	0.10	0.09	0.10

Results of operations by quarter for the year ended December 31, 2003 were (thousands of dollars, except per share) as follows:

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
2003				
Revenues	$29,025	$29,654	$39,337	$39,463
Results of operations from exploration and production activities(1)	10,159	10,187	11,996	10,791
Net earnings (loss)(2)	$ 1,721	$ 1,924	$ 2,965	$ 636
Net earnings (loss) per share:(2)				
Basic	$ 0.03	$ 0.04	$ 0.06	$ 0.01
Diluted	0.03	0.04	0.05	0.01

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

(2) Applicable to common stockholders

19. SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (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 DECEMBER 31,		
	2004	2003	2002
Costs incurred during the year:(1)			
Property acquisition costs			
Unproved	$ 16,687	$ 4,107	$ 5,217

Proved	--	--	--
Exploration	93,682	42,081	32,293
Development	31,610	25,586	38,998
Asset retirement cost accruals, net	4,921	1,326	--
	$146,900	$73,100	$76,508

(1) Costs incurred during the years ended December 31, 2004, 2003 and 2002 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $11,924,000, $10,030,000 and $11,684,000, respectively.

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

	DECEMBER 31,	
	2004	2003
Capitalized costs	$1,377,649	$1,230,643
Accumulated depletion	931,033	829,089
Net capitalized costs	$ 446,616	$ 401,554

At December 31, 2004 and 2003, unevaluated costs of $34,731,000 and $30,542,000, 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 31,		
	2004	2003	2002
Operating Revenues:			
Oil	$ 36,060	$ 35,032	$ 54,595
Natural Gas	166,387	102,092	52,397
	202,447	137,124	106,992
Less:			
Oil and natural gas operating costs	14,035	11,260	11,935
Severance and ad valorem taxes	9,394	7,608	8,235
Depletion	101,944	74,456	59,799
Accretion expense(1)	601	667	--
Impairment of long-lived assets	--	--	69,124

Income tax	19,342	4,249	(22,002)
	145,316	98,240	127,091
Results of operations from oil and natural gas producing activities	$ 57,131	$ 38,884	$(20,099)
Depletion expense per Mcfe	$ 2.88	$ 2.61	$ 2.07

(1) On January 1, 2003, the company adopted SFAS 143. The pro forma effects of the application of SFAS 143, as if the statement had been adopted on January 1, 2001, would have been an additional accretion expense of $470 thousand for the year 2002.

ESTIMATED QUANTITIES OF PROVED RESERVES

The following table sets forth the net proved reserves of the Company as of December 31, 2004, 2003 and 2002, and the changes therein during the years then ended. The reserve information was reviewed by T. J. Smith & Company, Inc., independent reservoir engineers, for 2004, 2003 and 2002. All of the Company's oil and natural gas producing activities are located in the United States.

	Oil (MBbls)	Gas (MMcf)
TOTAL PROVED RESERVES:		
BALANCE AT DECEMBER 31, 2001	24,346	176,922
Production during 2002	(2,213)	(15,578)
Discoveries and extensions	41	13,786
Revisions of previous quantity estimates and other(1)	(12,249)	(67,504)
BALANCE AT DECEMBER 31, 2002	9,925	107,626
Production during 2003	(1,403)	(20,142)
Discoveries and extensions	31	18,474
Sale of reserves in-place	(571)	(1,238)
Revisions of previous quantity estimates and other	(90)	(6,251)
BALANCE AT DECEMBER 31, 2003	7,892	98,469
Production during 2004	(1,270)	(27,839)
Discoveries and extensions	212	21,783
Revisions of previous quantity estimates and other	(470)	8,586
BALANCE AT DECEMBER 31, 2004	6,364	100,999
PROVED DEVELOPED RESERVES:		
Balance at December 31, 2001	10,752	101,397
Balance at December 31, 2002	6,841	86,248
Balance at December 31, 2003	5,016	82,279
Balance at December 31, 2004	4,716	85,507

(1) Primarily as a result of Kent Bayou. See Note 4. 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 DECEMBER 31,		
	2004	2003	2002
Future cash flows	$ 897,839	$ 842,945	$ 829,538
Future production costs	(139,112)	(118,775)	(137,215)
Future development costs	(39,352)	(30,044)	(43,474)
Future net cash flows before income taxes	719,375	694,126	648,849
Future taxes on income	(135,472)	(116,570)	(99,852)
Future net cash flows	583,903	577,556	548,997
Discount to present value at 10 percent per annum	(113,546)	(121,673)	(119,162)
Standardized measure of discounted future net cash flows	$ 470,357	$ 455,883	$ 429,835

The average price for natural gas in the above computations was $6.40, $6.07 and $4.96 per Mcf at December 31, 2004, 2003, and 2002, respectively. The average price used for crude oil in the above computations was $42.33, $32.05 and $31.82 per Bbl at December 31, 2004, 2003, and 2002, 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, 2004, 2003 and 2002 (thousands of dollars):

	YEAR ENDED DECEMBER 31, 2004	2003	2002
Balance at Beginning of Period	$ 455,883	$ 429,835	$ 402,917
Sales of oil and gas, net of production costs	(179,018)	(118,256)	(86,822)
Changes in sales & transfer prices, net of production costs	32,203	82,200	348,960
Revisions of previous quantity estimates	22,468	(24,563)	(373,928)
Sales of reserves-in-place	--	(5,026)	--
Current year discoveries, extensions and improved recovery	117,178	67,676	40,376
Changes in estimated future development costs	(11,331)	(7,824)	(9,840)
Development costs incurred during the period	9,851	20,511	38,998
Accretion of discount	45,588	42,983	40,292
Net change in income taxes	(23,278)	(21,186)	(3,676)
Change in production rates (timing) and other	813	(10,467)	32,558
Net change	14,474	26,048	26,918
Balance at End of Period	$ 470,357	$ 455,883	$ 429,835

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

On September 25, 2003, the Company retained the services of BDO Seidman LLP as its new independent accountant, replacing Ernst & Young LLP, to audit the Company's financial statements. The Company's Current Report on Form 8-K, dated September 25, 2003, is incorporated by reference in this Form 10-K, and the information included in Item 4 of the Form 8-K is included as Exhibit 99.1 to this Form 10-K.

ITEM 9A. CONTROLS AND PROCEDURES

We conducted an evaluation under the supervision and with the participation of Meridian's management, including our Chief Executive Officer and Chief Accounting Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934) as of the end of the fourth quarter of 2004. Based upon that evaluation, our Chief Executive Officer and Chief Accounting Officer concluded that the design and operation of our disclosure controls and procedures are effective. There have been no significant changes in our internal controls or in other factors during the fourth quarter of 2004 that could significantly affect these controls except as noted below.

In the course of preparing our first management report on internal control over financial reporting as required by Section 404 of the Sarbanes-Oxley Act, we identified, and remediated in the fourth quarter of 2004, certain material weaknesses in the system of internal controls. The adjustments to the Company's consolidated financial statements resulting from such remediation were not material, either individually or in the aggregate. The material weaknesses that were remediated related to (a) a lack of effective controls over the coding of certain workover invoices, (b) controls over the revenue accrual process and (c) a lack of proper segregation of duties associated with the initiation and execution of wire transfers.

In accordance with an exemptive order by the SEC, management's annual report on internal control over financial reporting, required by Item 308(a) of Regulation S-K, and the related Attestation report of the Company's independent auditors, required by Item 308(b) of Regulation S-K, are not required to be filed on the date that this report is otherwise due to be filed. Such information will be filed on or before May 2, 2005 by an amendment to this report.

PART III

The information required in Items 10, 11, 12, 13 and 14 is incorporated by reference to the Company's definitive Proxy Statement to be filed with the Securities and Exchange Commission on or before May 2, 2005.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report:

1. Financial Statements included in Item 8:

(i) Independent Registered Public Accounting Firms' Reports

(ii) Consolidated Balance Sheets as of December 31, 2004 and 2003

(iii) Consolidated Statements of Operations for each of the three years in the period ended December 31, 2004

(iv) Consolidated Statements of Changes in Stockholders' Equity for each of the three years in the period ended December 31, 2004

(v) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2004

(vi) Notes to Consolidated Financial Statements

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

2. Financial Statement Schedules:

(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:

3.1 Third Amended and Restated Articles of Incorporation of the Company (incorporated by reference to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 1998).

3.2 Amended and Restated Bylaws of the Company (incorporated by reference to the Company's Quarterly Report on Form

10-Q for the three months ended September 30, 1998).

3.3 Certificate of Designation for Series C Redeemable Convertible Preferred Stock dated March 28, 2002 (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2002).

4.1 Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1, as amended (Reg. No. 33-65504)).

*4.2 Common Stock Purchase Warrant of the Company dated October 16, 1990, issued to Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 10.8 of the Company's Annual Report on Form 10-K for the year ended December 31, 1991, as amended by the Company's Form 8 filed March 4, 1993).

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4.9	Amendment No. 1, dated as of January 29, 2001, to Rights Agreement, dated as of May 5, 1999, by and between the Company and American Stock Transfer & Trust Co., as rights agent (incorporated by reference from the Company's Current Report on Form 8-K dated January 29, 2001).
4.10	First Amendment to Subordinated Credit Agreement, dated December 5, 2001, between Meridian and Fortis Capital Corp. (incorporated by reference to Exhibit 4.17 of the Company's Registration statement on Form S-3, as amended (Reg. No. 333-75414)).
10.1	See exhibits 4.2 through 4.12 for additional material contracts.
*10.2	The Meridian Resource Corporation 1990 Stock Option Plan (incorporated by reference to Exhibit 10.6 of the Company's Annual Report on Form 10-K for the year ended December 31, 1991, as amended by the Company's Form 8 filed March 4, 1993).
*10.3	Employment Agreement dated August 18, 1993, between the Company and Joseph A. Reeves, Jr. (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1995).
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**23.1	Consent of BDO Seidman LLP.
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**23.3	Consent of T. J. Smith & Company, Inc.
**31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.

**31.2	Certification of President pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.
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**99.1	Item 4 of the Company's Current Report on Form 8-K, dated September 25, 2003.

* Management contract or compensation plan.

** Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this 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: March 15, 2005

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	Date
BY: /s/ JOSEPH A. REEVES, JR. Joseph A. Reeves, Jr.	Chief Executive Officer (Principal Executive Officer) Director and Chairman of the Board	March 15, 2005
BY: /s/ MICHAEL J. MAYELL Michael J. Mayell	President and Director	March 15, 2005

BY: /s/ LLOYD V. DELANO -------------------------------- Lloyd V. DeLano	Chief Accounting Officer	March 15, 2005
BY: /s/ E. L. HENRY -------------------------------- E. L. Henry	Director	March 15, 2005
BY: /s/ JOE E. KARES -------------------------------- Joe E. Kares	Director	March 15, 2005
BY: /s/ GARY A. MESSERSMITH -------------------------------- Gary A. Messersmith	Director	March 15, 2005
BY: /s/ DAVID W. TAUBER -------------------------------- David W. Tauber	Director	March 15, 2005

BY: /s/ JOHN B. SIMMONS -------------------------------- John B. Simmons	Director	March 15, 2005
BY: /s/ FENNER R. WELLER, JR. -------------------------------- Fenner R. Weller, Jr.	Director	March 15, 2005
BY: /s/ JAMES R. MONTAGUE -------------------------------- James R. Montague	Director	March 15, 2005

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