MERIDIAN RESOURCE CORP
Form 10-K
March 16, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from ____________ to ____________

Commission file number: 1-10671

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

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

1401 ENCLAVE PARKWAY, SUITE 300, HOUSTON, TEXAS	77077
(Address of principal executive offices)	(Zip Code)

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

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

(Title of each class)	(Name of each exchange on which registered)
Common Stock, $0.01 par value	New York Stock Exchange
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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] No [X]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes [ ] No [X]

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one)

Large Accelerated Filer [ ] Accelerated Filer [X] Non-Accelerated Filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ]   No [X]

Aggregate market value of shares of common stock held by non-affiliates of the Registrant at June 30, 2005	$410,169,664
Number of shares of common stock outstanding at March 1, 2006:	86,838,554

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 1, 2006.

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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 have historically 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, 2005, we had proved reserves of 111 Bcfe with a present value of future net cash flows before income taxes of approximately $681 million ($557 million after tax). Seventy-two percent (72%) of our proved reserves were natural gas and approximately seventy-five percent (75%) were classified as proved developed. We own interests in 19 fields and 104 wells, and we operate approximately 90% of our total production.

We have historically generated the majority of our exploration projects. We believe that we are among the leaders in the industry in the application of 3-D seismic technology and have participated in the discovery of more than 800 Bcfe of new reserves since 1992. 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.

Our people, high cash flows, strategic acreage positions and database of 2-D and 3-D seismic data provide us with a significant presence in the core Gulf Coast area and beyond, enabling us to exploit multiple exploratory and development prospects in multiple basins. The Company's goal is to balance its current capital expenditures such that it can add reserves and production from longer-lived reserves to equate up to 50% of total production and reserves.

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;

- Supplement and balance our geographic focus in the mature south Louisiana and south Texas Gulf Coast core producing areas, with newly-developed resource play opportunities that can generate substantial reserve additions and increase the average reserve life for the Company;

- Apply the latest technology to a rigorous process in the generation and development of lower-risk exploration prospects, utilizing 3-D seismic and other technological advances to maximize our probability of success, optimize well locations and reduce our finding costs;

- Maximize percentage ownership in each drilling prospect relative to the 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 currently have interests in leases and options to lease acreage in approximately 163,000 gross acres in Louisiana, Texas and the Gulf of Mexico, including approximately 35,000 net acres located in unconventional gas regions. 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.

Meridian 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 ("SEC"), on the internet at www.tmrc.com and www.sec.gov.

EXPLORATION STRATEGY

Meridian has traditionally focused its exploration strategy in areas where large accumulations of oil and natural gas have been found and where we believe substantial new oil and natural gas reserve additions can be achieved. Our exploration programs have been extensively filtered by the use of 3-D seismic technology, including the latest, state-of-the-art interpretation techniques to mitigate risks and look for indications of hydrocarbons where standard methods have not identified similar opportunities. We also attempt to match our exploration risks with expected results by retaining working interests in the range between 50% and 100% in the Company's onshore wells. Our working interests may vary in certain prospects, depending on participation structure, the ability to offset potential assessed risk, capital availability and other factors. As a result of our disciplined method of combining both sub-surface geology and 3-D seismic technology in our exploration, plus our attention to all technical aspects, we believe that we are able to develop a more accurate definition of the risk profile of exploration prospects and plays than was previously available using traditional exploration techniques. We therefore believe that our reliance on technology will increase our probability of success and reduce our dry-hole costs compared to alternatives that do not place the same emphasis on technical detail.

Our business strategy further includes the pursuit and development of a balanced exploration inventory, geologically and geographically, including deeper higher-risk, yet larger potential prospects, along with shallower, lower-risk plays with large acreage positions that are supported by seismically-driven hydrocarbon indicators. Together, these allow for repeatable, multiple-well extensions.

In addition, we have extended our exploration inventory (and therefore our strategy) to include multiple unconventional (tight gas) and resource (shale-styled) plays. As with our conventional exploration efforts, we believe that we will have a competitive advantage in our expanded areas of exploration because of our approach to each - retaining the best of experienced technical teams, who understand not only the exploration aspects, but also the crucial methods and techniques best suited for drilling and completion activities in each area. As we proceed, we will continue to better control our positions by acquiring large acreage positions and controlling our costs. We believe that our continued, methodical application of the latest technology to the development of exploration concepts, as well as to drilling and completion procedures in these new and expanded areas of exploration, will provide the Company continued success in the future development of new oil and gas reserves.

We believe that this expansion will further improve the probability of success, reduce dry-hole costs and allow us to capitalize on the current high cash flows from our short-lived reserve basin in the Gulf Coast region. These new plays, while offering considerably reduced rates of production per well, offer more opportunities for development wells after the play is proved. Collectively, it is anticipated that the extension of our exploration effort into the unconventional tight or shale gas plays can provide substantial reserve additions and more predictable production rate increases.

As a part of our effort to mitigate the risks associated with any new exploration play, we will continue to apply a rigorous and disciplined review of each, utilizing the latest in technological advances, including both geophysical and geochemical techniques, with respect to analysis, evaluation and completions.

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, 2005. The reserve volumes were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	LOUISIANA	GULF OF MEXICO	
PRODUCTION FOR THE YEAR ENDED DECEMBER 31, 2005			
Oil (MBbls)	828	54	
Natural Gas (MMcf)	19,886	604	
RESERVES AS OF DECEMBER 31, 2005			
Oil (MBbls)	4,273	904	
Natural Gas (MMcf)	70,430	9,487	
ESTIMATED FUTURE NET CASH FLOWS ($000)(1)			$
PRESENT VALUE OF FUTURE NET CASH FLOWS BEFORE INCOME TAXES ($000)(1)			$
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS ($000)(1)			$

(1) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of $123.7 million, 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, 2005, we used the expected realized prices at December 31, 2005, which were $59.37 per Bbl of oil and $10.40 per Mcf of natural gas and do not reflect the impact of hedges.

PRODUCTIVE WELLS

At December 31, 2005, 2004 and 2003, we held interests in the following productive wells. As of December 31, 2005, we own 24 gross (4.0 net) wells in the Gulf of Mexico which are outside operated and net to 1.5 oil wells and 2.5 natural gas wells. In addition, of the total well count for 2005, 3 wells (1.1 net) are multiple completions.

	2005		2004		2003	
	GROSS	NET	GROSS	NET	GROSS	NET
Oil Wells	35	24	35	22	31	20
Natural Gas Wells	69	39	68	34	60	27
Total	104	63	103	56	91	47

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,

2005. Information set forth in the following table is based on reserve reports prepared in accordance with the rules and regulations of the SEC. The reserve estimates were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	PROVED RESERVES AT DEC	
	DEVELOPED PRODUCING	DEVELOPED NON-PRODUCING
		(DOLLARS IN THO
Net Proved Reserves:		
Oil (MBbls)..	1,594	1,898
Natural Gas (MMcf)...	34,700	27,824
Natural Gas Equivalent (MMcfe).....................................	44,263	39,214
Estimated Future Net Cash Flows(1).................................		
Present Value of Future Net Cash Flows (before income taxes)(1)..		
Standardized Measure of Discounted Future Net Cash Flows(1)......		

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(1) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of $123.7 million, 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, 2005, we used the expected realized prices at December 31, 2005, which were $59.37 per Bbl of oil and $10.40 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 SEC.

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 SEC, 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 2005, 2004 and 2003.

	GROSS WELLS			NET WELLS		
	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL
EXPLORATORY WELLS						
Year ended December 31, 2005	10	13	23	8.0	10.8	18.8
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
DEVELOPMENT WELLS						
Year ended December 31, 2005	1	--	1	0.3	--	0.3
Year ended December 31, 2004	4	--	4	3.2	--	3.2
Year ended December 31, 2003	--	1	1	--	0.9	0.9

Meridian had 3 gross (1.9 net) wells in progress at December 31, 2005.

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 2005, 2004 and 2003.

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
PRODUCTION:			
Oil (MBbls)	882	1,270	1,403
Natural gas (MMcf)	20,490	27,839	20,142
Natural gas equivalent (MMcfe)	25,781	35,457	28,563
AVERAGE PRICES:			
Oil ($/Bbl)	$ 39.29	$ 28.40	$ 24.97
Natural gas ($/Mcf)	$ 7.84	$ 5.98	$ 5.07
Natural gas equivalent ($/Mcfe)	$ 7.57	$ 5.71	$ 4.80

PRODUCTION EXPENSES:

Lease operating expenses ($/Mcfe)	$ 0.61	$ 0.40	$ 0.39
Severance and ad valorem taxes ($/Mcfe)	$ 0.34	$ 0.26	$ 0.27

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, 2005. 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, 2005			
	DEVELOPED		UNDEVELOPED	
REGION	GROSS	NET	GROSS	NET
LOUISIANA	31,997	22,931	27,321	22,706
TEXAS	--	--	40,229	20,327
GULF OF MEXICO	29,519	6,088	7,500	2,883
TOTAL	61,516	29,019	75,050	45,916

In addition to the above acreage, we currently have options or farm-ins to acquire leases on approximately 25,267 gross (17,221 net) acres of undeveloped land located in Louisiana, and 1,750 gross (734 net) acres in Texas. Our fee holdings of approximately 25 developed acres and 4,300 undeveloped acres have been included in the acreage table above 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 5,700 acres in 2006, 23,000 acres in 2007, and 12,000 acres in 2008.

GEOLOGIC/LAND AND OPERATIONS GEOPHYSICAL EXPERTISE

Meridian employs approximately 70 full-time non-union employees and 15 contract employees. This staff includes geologists, geophysicists, land and engineering staff with over 540 combined years of experience in generating and developing onshore and offshore prospects in the Louisiana and Texas Gulf Coast region. Our geologists and geophysicists generate and review all prospects using 2-D and 3-D seismic technology and analogues to producing wells in the areas of interest.

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 2005, 2004 and 2003.

CUSTOMER	YEAR ENDED DECEMBER 31, 2005	2004	2003
Superior Natural Gas	46%	45%	19%
Crosstex/Louisiana Intrastate Gas	19%	22%	24%
Conoco, Inc.	--	--	10%

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.

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 $69.91 per Bbl and the Gulf Coast spot market natural gas price at Henry Hub, Louisiana, has ranged from $1.08 to $15.40 per MMBtu. The average price we received during the year ended December 31, 2005, was $7.57 per Mcfe compared to $5.71 per Mcfe during the year ended December 31, 2004. 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 represents 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 allowable for wells on a market demand or conservation basis.

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

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

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

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

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

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

RESOURCE CONSERVATION AND RECOVERY ACT. The Resource Conservation and Recovery Act ("RCRA") is the 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.

ITEM 1A. RISK FACTORS

Each of the following risk factors could adversely affect our business, operating results and financial condition. It is not possible to foresee or identify all such factors. Investors should not consider this list an exhaustive statement of all risks and uncertainties. This report also contains forward-looking statements that involve risks and uncertainties. Our actual results may differ from those anticipated in these forward-looking statements as a result of both the risks described below and factors described elsewhere in this report. You should read the section below entitled "Forward-Looking Statements" for further discussion of these matters.

OUR INDEBTEDNESS MAY ADVERSELY AFFECT OPERATIONS AND LIMIT OUR GROWTH.

As of December 31, 2005, we had long-term indebtedness of approximately $75.0 million compared to approximately $377.6 million of stockholders' equity. If we are unable to generate sufficient cash flows from operations in the future to service our debt, we may need to refinance all or a portion of our existing debt or to obtain additional financing. Such refinancing or additional financing may not be possible. Our ability to meet our debt service obligations and to reduce our total indebtedness will depend on our future performance and our ability to maintain or increase cash flows from our operations. These outcomes are subject to general economic conditions and to financial, business and other factors affecting our operations, many of which we do not control, including the prevailing market prices for oil and natural gas. Our business may not continue to generate cash flows at or above current levels.

BORROWING LIMITS UNDER OUR CREDIT FACILITY ARE SUBJECT TO REDETERMINATION.

As of December 31, 2005, we have outstanding indebtedness of $75.0 million under our revolving credit facility, which is $55 million less than the current limit to our borrowings under that facility. The borrowing base under that facility is subject to semi-annual redeterminations by our lenders. Our borrowing base is determined primarily by our oil and gas reserve amounts. Our lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that our oil and gas reserves at the time of redetermination are inadequate to support the borrowing base then in effect. In the event our then-redetermined borrowing base is less than our outstanding borrowings under the facility, we will be required to repay the deficit within a 90-day period. If we are required to repay debt under our credit facility as a result of a downward borrowing base redetermination, we may not be able to obtain alternate borrowing sources at commercially reasonable rates.

OUR LENDERS IMPOSE RESTRICTIONS ON US THAT LIMIT OUR ABILITY TO CONDUCT BUSINESS AND COULD ADVERSELY AFFECT OPERATIONS.

Our credit facility contains restrictive covenants. The restrictive covenants impose significant operating and financial restraints that could impair our ability to obtain future financing, to make capital expenditures, to pay dividends, to engage in mergers or acquisitions, to withstand future downturns in our business or in the general economy or to otherwise conduct necessary corporate activities. Furthermore, we have pledged substantially all of our oil and natural gas properties and the stock of all of our principal operating subsidiaries as collateral for the indebtedness under our credit facility. If we are in material default of our obligations under that credit facility, the lenders are entitled to liens on additional oil and natural gas properties. This pledge of collateral to our credit facility lenders could impair our ability to obtain additional financing on favorable terms.

A default under a restrictive covenant could result in the lenders accelerating the payment of all borrowed

funds, together with accrued and unpaid interest. We may not be able to remit such an accelerated payment or to access sufficient funds from alternative sources to remit any such payment. Even if we could obtain additional financing, the terms of that financing may not be favorable or acceptable to us.

THE OIL AND NATURAL GAS MARKETS ARE VOLATILE AND EXPOSE US TO FINANCIAL RISKS.

Our profitability, cash flow and the carrying value of our oil and gas properties are highly dependent on the market prices of oil and natural gas. Historically, the oil and natural gas markets have proven cyclical and volatile as a result of factors that are beyond our control. These factors include changes in tax laws, the level of consumer product demand, weather conditions, the price and availability of alternative fuels, the price and level of imports and exports of oil and natural gas, worldwide economic, political and regulatory conditions, and action taken by the Organization of Petroleum Exporting Countries.

Any significant decline in oil and natural gas prices or any other unfavorable market conditions could have a material adverse effect on our financial condition and on the carrying value of our proved reserves. Consequently, we may not be able to generate sufficient cash flows from operations to meet our obligations and to make planned capital expenditures. Price declines may also affect the measure of discounted future net cash flows of our reserves, a result that could adversely impact the borrowing base under our credit facility and may increase the likelihood that we will incur additional impairment charges on our oil and natural gas properties for financial accounting purposes.

OUR HEDGING TRANSACTIONS MAY NOT ADEQUATELY PREVENT LOSSES.

We cannot predict future oil and natural gas prices with certainty. To manage our exposure to the risks inherent in such a volatile market, from time to time, we have entered into commodities futures, swap or option contracts to hedge a portion of our oil and natural gas production against market price changes. Hedging transactions are intended to limit the negative effect of future price declines, but may also prevent us from realizing the benefits of price increases above the levels reflected in the hedges.

OUR RESERVE ESTIMATES MAY PROVE TO BE INACCURATE AND FUTURE NET CASH FLOWS ARE UNCERTAIN.

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 assumptions and estimates.

WE DEPEND ON KEY PERSONNEL TO EXECUTE OUR BUSINESS PLANS.

The loss of any key executives or any other key personnel could have a material adverse effect on our operations. We depend on the efforts and skills of our key executives, including Joseph A. Reeves, Jr., Chairman of the Board and Chief Executive Officer, and Michael J. Mayell, President and Chief Operating Officer. Moreover, as we continue to grow our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel.

WE COMPETE AGAINST SIGNIFICANT PLAYERS IN THE OIL AND NATURAL GAS INDUSTRY, AND OUR FAILURE IN THE LONG-TERM TO COMPLETE FUTURE ACQUISITIONS SUCCESSFULLY AND GENERATE COMMERCIAL EXPLORATION AND DEVELOPMENT DRILLING OPPORTUNITIES COULD REDUCE OUR EARNINGS AND CAUSE REVENUES TO DECLINE.

The oil and natural gas industry is highly competitive. Our ability to acquire additional properties and to discover additional reserves depends on our ability to consummate transactions in this highly competitive environment. We compete with major oil companies, other independent oil and natural gas companies, and individual producers and operators. Many of these competitors have access to greater financial and personnel resources than those to which we have access. Moreover, the oil and natural gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial and other consumers. Increased competition causing oversupply or depressed prices could materially adversely affect our revenues.

THE OIL AND NATURAL GAS MARKETS ARE HEAVILY REGULATED.

We are subject to various federal, state and local laws and regulations. These laws and regulations govern safety, exploration, development, taxation and environmental matters that are related to the oil and natural gas industry. To conserve oil and natural gas supplies, regulatory agencies may impose price controls and may limit our production. Certain laws and regulations require drilling permits, govern the spacing of wells and the prevention of waste, and limit the total number of wells drilled or the total allowable production from successful wells. Other laws and regulations govern the handling, storage, transportation and disposal of oil and natural gas and any byproducts produced in oil and natural gas operations. These laws and regulations could materially adversely impact our operations and our revenues.

Laws and regulations that affect us may change from time to time in response to economic or political conditions. Thus, we must also consider the impact of future laws and regulations that may be passed in the jurisdictions where we operate. We anticipate that future laws and regulations related to the oil and natural gas industry will become increasingly stringent and cause us to incur substantial compliance costs.

THE NATURE OF OUR OPERATIONS EXPOSES US TO ENVIRONMENTAL LIABILITIES.

Our operations create the risk of environmental liabilities. We may incur liability to governments or to third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. We could potentially discharge oil or natural gas into the environment in any of the following ways:

- from a well or drilling equipment at a drill site,
- from a leak in storage tanks, pipelines or other gathering and transportation facilities,
- from damage to oil or natural gas wells resulting from accidents during normal operations, or
- from blowouts, cratering or explosions.

Environmental discharges may move through the soil to water supplies or adjoining properties, giving rise to additional liabilities. Some laws and regulations could impose liability for failure to obtain the proper permits for, to control the use of, or to notify the proper authorities of a hazardous discharge. Such liability could have a material adverse effect on our financial condition and our results of operations and could possibly cause our operations to be suspended or terminated on such property.

We may also be liable for any environmental hazards created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. Such liability would affect the costs of our acquisition of those properties. In connection with any of these environmental violations, we may also be charged with remedial costs. Pollution and similar environmental risks generally are not fully insurable.

Although we do not believe that our environmental risks are materially different from those of comparable companies in the oil and natural gas industry, we cannot assure you that environmental laws will not result in

decreased production, substantially increased costs of operations or other adverse effects to our combined operations and financial condition.

WE REQUIRE SUBSTANTIAL CAPITAL REQUIREMENTS TO FINANCE OUR OPERATIONS.

We have substantial anticipated capital requirements. Our ongoing capital requirements consist primarily of the need to fund our capital and exploration budget and the acquisition, development, exploration, production and abandonment of oil and natural gas reserves.

We plan to finance anticipated ongoing expenses and capital requirements with funds generated from the following sources:

- cash provided by operating activities;
- available cash and cash investments;
- capital raised through debt and equity offerings; and
- funds received under our bank line of credit.

Although we believe the funds provided by these sources will be sufficient to meet our cash requirements, the uncertainties and risks associated with future performance and revenues will ultimately determine our liquidity and our ability to meet anticipated capital requirements. If declining prices cause our revenues to decrease, we may be limited in our ability to replace our reserves, to maintain current production levels and to undertake or complete future drilling and acquisition activities. As a result, our production and revenues would decrease over time and may not be sufficient to satisfy our projected capital expenditures. We may not be able to obtain additional debt or equity financing in such a circumstance.

OUR OPERATIONS ENTAIL INHERENT CASUALTY RISKS FOR WHICH WE MAY NOT HAVE ADEQUATE INSURANCE.

We must continually acquire, explore and develop new oil and natural gas reserves to replace those produced and sold. Our hydrocarbon reserves and our revenues will decline if we are not successful in our drilling, acquisition or exploration activities. Although we have historically maintained our reserve base primarily through successful exploration and development operations, future efforts may not be similarly successful. Casualty risks and other operating risks could cause reserves and revenues to decline.

Our onshore and offshore operations are subject to inherent casualty risks such as hurricanes, fires, blowouts, cratering and explosions. Other risks include pollution, the uncontrollable flows of oil, natural gas, brine or well fluids, and the hazards of marine and helicopter operations such as capsizing, collision and adverse weather and sea conditions. These risks may result in injury or loss of life, suspension of operations, environmental damage or property and equipment damage, all of which would cause us to experience substantial financial losses.

Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipe, collapsed casing and separated cables. Our offshore properties involve higher exploration and drilling risks such as the cost of constructing exploration and production platforms and pipeline interconnections as well as weather delays and other risks. Although we carry insurance that we believe is in accordance with customary industry practices, we are not fully insured against all casualty risks incident to our business. We do not carry business interruption insurance. Should an event occur against which we are not insured, that event could have a material adverse effect on our financial position and our results from operations.

OUR OPERATIONS ALSO ENTAIL SIGNIFICANT OPERATING RISKS.

Our drilling activities involve risks, such as drilling non-productive wells or dry holes, which are beyond our control. The cost of drilling and operating wells and of installing production facilities and pipelines is uncertain. Cost overruns are common risks that often make a project uneconomical. The decision to purchase and to exploit a property depends on the evaluations made by our reserve engineers, the results of which are often inconclusive or subject to multiple interpretations. We may also decide to reduce or cease our drilling operations due to title problems, weather conditions, noncompliance with governmental requirements or shortages and delays in the delivery or availability of equipment or fabrication yards.

WE MAY NOT BE ABLE TO MARKET EFFECTIVELY OUR OIL AND NATURAL GAS PRODUCTION.

We may encounter difficulties in the marketing of our oil and natural gas production. Effective marketing depends on factors such as the existing market supply and demand for oil and natural gas and the limitations imposed by governmental regulations. The proximity of our reserves to pipelines and the available capacity of such pipelines and other transportation, processing and refining facilities also affect our marketing efforts. Even if we discover hydrocarbons in commercial quantities, a substantial period of time may elapse before we begin commercial production. If pipeline facilities in an area are insufficient, we may have to wait for the construction or expansion of pipeline capacity before we can market production from that area. Another risk lies in our ability to negotiate commercially satisfactory arrangements with the owners and operators of production platforms in close proximity to our wells. Also, natural gas wells may be shut in for lack of market demand or because of the inadequate capacity or unavailability of natural gas pipelines or gathering systems.

WE ARE DEPENDENT ON OTHER OPERATORS WHO INFLUENCE OUR PRODUCTIVITY.

We have limited influence over the nature and timing of exploration and development on oil and natural gas properties we do not operate, including limited control over the maintenance of both safety and environmental standards. The operators of those properties may:

- refuse to initiate exploration or development projects (in which case we may propose desired exploration or development activities);

- initiate exploration or development projects on a slower schedule than we prefer; or

- drill more wells or build more facilities on a project than we can adequately finance, which may limit our participation in those projects or limit our percentage of the revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

OUR WORKING INTEREST OWNERS FACE CASH FLOW AND LIQUIDITY CONCERNS.

If oil and natural gas prices decline, many of our working interest owners may experience liquidity and cash flow problems. These problems may lead to their attempting to delay the pace of drilling or project development in order to conserve cash. Any such delay may be detrimental to our projects. In most cases, we can influence the pace of development by enforcing our joint operating agreements. Some working interest owners, however, may be unwilling or unable to pay their share of the project costs as they become due. A working interest owner may declare bankruptcy and refuse or be unable to pay its share of the project costs and we would be obligated to pay that working interest owner's share of the project costs.

OUR INABILITY TO ACQUIRE OR INTEGRATE ACQUIRED COMPANIES OR TO DEVELOP NEW EXPLORATION PROSPECTS MAY INHIBIT OUR GROWTH.

From time to time and under certain circumstances, our business strategy may include acquisitions of businesses that complement or expand our current business and acquisition and development of new exploration prospects that complement or expand our prospect inventory. We may not be able to identify attractive acquisition or prospect opportunities. Even if we do identify attractive opportunities, we may not be able to complete the acquisition of the business or prospect or to do so on commercially acceptable terms. If we do complete an acquisition, we must anticipate difficulties in integrating its operations, systems, technology, management and other personnel with our own. These difficulties may disrupt our ongoing operations, distract our management and employees and increase our expenses. Even if we are able to overcome such difficulties, we may not realize the anticipated benefits of any acquisition. Furthermore, we may incur additional debt or issue additional equity securities to finance any future acquisitions. Any issuance of additional securities may dilute the value of shares currently outstanding.

TERRORIST ATTACKS AND THREATS OR ACTUAL WAR MAY NEGATIVELY AFFECT OUR BUSINESS, FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Our business is affected by general economic conditions and fluctuations in consumer confidence and spending, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Terrorist attacks against U.S. targets, as well as events occurring in response to or in connection with them, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions impacting our suppliers or our customers, may adversely impact our operations. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. These occurrences could have an adverse impact on energy prices, including prices for our natural gas and crude oil production. In addition, disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any or a combination of these occurrences could have a material adverse effect on our business, financial condition and results of operations.

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, this Risk Factors section, the Management's Discussion and Analysis of Financial Condition and Results of Operations section and other sections of this report and our other filings with the Securities and Exchange Commission under the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

PRODUCING PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

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 in Louisiana, as a result of Meridian's satisfying a prior adverse judgment in favor of Amoco Production Company. Meridian has filed an answer denying Hawkins' 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 that it had been paid by Hawkins. The Company has not provided any amount for this matter in its financial statements at December 31, 2005.

TITLE/LEASE DISPUTES. Title and lease disputes may arise due to various events that have occurred in the various states in which the Company operates. These disputes are usually small and could lead to the Company over- or under-stating our reserves when a final resolution to the title dispute is made.

ENVIRONMENTAL LITIGATION. Various landowners have sued Meridian (along with numerous other oil companies) in various similar lawsuits concerning several fields in which the Company has had operations. 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. The Company, in certain instances, has indemnified third parties from the claims made in these lawsuits. The Company has not provided any amount for this matter in its financial statements at December 31, 2005.

LITIGATION INVOLVING INSURABLE ISSUES. 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

No matters were submitted to a vote of Meridian's security holders during the fourth quarter of 2005.

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
2005:		
First quarter ...	$6.36	$4.88
Second quarter ..	5.45	3.77

Third quarter ...	5.31	3.39
Fourth quarter ..	4.90	3.77
2004:		
First quarter ...	$6.52	$5.00
Second quarter ..	7.65	6.03
Third quarter ...	9.00	6.76
Fourth quarter ..	9.02	5.20

The closing sale price of the common stock on March 1, 2006, as reported on the New York Stock Exchange Composite Tape, was $4.16. As of March 1, 2006, we had approximately 792 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 senior secured credit facility from paying any cash dividends on common stock or for purchase of shares of common stock without the prior consent of the lenders.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information as of December 31, 2005, 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	Num remai futu equity (exc reflect
	(a)	(b)	
Equity compensation plans approved by security holders	6,781,454	$3.44	
Equity compensation plans not approved by security holders	--	--	
Total	6,781,454	$3.44	

(1) Does not include 3,850,000 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.

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,				
	2005	2004	2003	2002	2001
	(In thousands, except prices and per share information)				
A. SUMMARY OF OPERATING DATA					
Production:					
Oil (MBbls)	882	1,270	1,403	2,213	2,918
Natural gas (MMcf)	20,490	27,839	20,142	15,578	22,085
Natural gas equivalent (MMcfe)	25,781	35,457	28,563	28,856	39,594
Average prices:					
Oil ($/Bbl)	$ 39.29	$ 28.40	$ 24.97	$ 24.67	$ 25.17
Natural gas ($/Mcf)	7.84	5.98	5.07	3.36	4.67
Natural gas equivalent ($/Mcfe)	7.57	5.71	4.80	3.71	4.46
B. SUMMARY OF OPERATIONS					
Total revenues	$195,696	$203,118	$137,479	$107,470	$178,060
Depletion and depreciation	97,354	102,915	75,441	60,972	67,450
Net earnings (loss)(1)	27,849	29,248	7,246	(52,012)	22,551
Net earnings (loss) per share:(1)					
Basic	$ 0.33	$ 0.41	$ 0.14	$ (1.05)	$ 0.47
Diluted	0.31	0.37	0.13	(1.05)	0.43
Dividends per:					
Common share	$ --	$ --	$ --	$ --	$ --
Redeemable preferred share	2.60	8.50	8.50	5.90	--
Preferred share	--	--	--	--	0.11
Weighted average common shares outstanding - basic	84,527	72,084	53,325	49,763	48,350
C. SUMMARY BALANCE SHEET DATA					
Total assets	$555,802	$513,274	$448,400	$456,240	$507,900
Long-term obligations, inclusive of current maturities	75,000	75,129	152,320	203,750	210,000
Redeemable preferred stock	--	31,589	60,446	69,690	--
Stockholders' equity	377,565	316,041	184,335	133,393	188,221

(1) Applicable to common stockholders.

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

GENERAL

Meridian is an independent oil and natural gas company that explores for, acquires and develops oil and natural gas properties utilizing 3-D seismic technology. Our operations have historically been focused on the onshore oil and gas regions in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico. Declines in the existence of conventional exploration projects in very mature producing basins, such as south Louisiana and the shallow shelf areas of the Gulf of Mexico, have impacted the number of economic prospects available for drilling. This is partly the result of better technology that has improved the industry's ability to determine probabilities of success, and partly the result of new projects being smaller in size compared to the decline rates exhibited by the giant fields discovered, generally, prior to the 1980s.

As a result, the Company made a shift during 1999 and extended what had been a highly successful exploration program during the early 1990s, from drilling purely deep, higher-risk, yet higher-potential prospects, to place more emphasis on the development of an exploration inventory of shallower, lower-risk, repeatable, multi-well plays. This shift was the genesis of two very successful exploration plays--Thornwell and Biloxi Marshlands--where multiple wells were drilled either just above pressures, or the first sands into geo-pressures. In both instances, the Company developed processing and interpretation techniques that identified direct hydrocarbon indicators and developed reserves with probabilities of success levels greater than 60% each.

Meridian's management believes that the basin itself still contains both tremendous attributes--high producing rates, high cash flows and returns, plus lower lift costs once proved--and remaining opportunities for a company, such as Meridian, that possesses a unique position in the region--a position marked by technical knowledge and expertise, relationships, acreage positions, seismic inventory and data and prospect inventory. However, the fact remains that the replacement of reserves year after year in this region continues to be more and more difficult under current conditions.

With the recent increase in commodity prices, the industry is now experiencing a new paradigm in domestic exploration. Recent price increases and enhanced technology has enabled the industry, as a whole, to consider domestic exploration projects that were once uneconomic. These are predominantly classed as "unconventional" (tight gas) and "resource" (shale or resource material) plays. The Barnett Shale field in northern Texas is the best, but not the only, example of this type of play. It is estimated that as much as 40% of current domestic production now stems from accumulation of this nature. These fields are quite prolific, extend over large areas, but are also very cost sensitive, with breakeven costs often at $5-$6 per mcf or more on large capital investments.

In recognition of the totality of circumstances, including the availability of these styles of play opportunities and the Company's high current cash position stemming from its higher-producing rate Gulf Coast properties, in early 2005, Meridian's management introduced as a part of its business plan, the further expansion of its exploration program to include the identification and development of unconventional and resource plays into its portfolio. Since that decision, the Company has entered into joint ventures and acquired strategic acreage positions in basins recognized for both the unconventional and resource exploration plays. The first of these was an unconventional or tight gas play in East Texas, near the highly prolific Double A field, where we own approximately 7,000 acres and began to drill our first wells during the first quarter of 2006. Others include the purchase of two separate acreage positions of approximately 18,000 acres and 15,000 acres, with plans to extend positions in each, based on the Company's research and drilling operations. The location of the Company's resource plays will not be identified until it has had the opportunity to secure control of protective acreage positions within each. In addition, the Company has expanded its technical and business development staff to include a team of experienced professionals and consultants who will be primarily responsible for the further extension of the Company's reserve base and reserve life in the unconventional resource plays.

Our drilling program for 2005 was dominated by exploration in the Biloxi Marshlands area and exploitation of seismic anomalies in Terrebonne Parish, under an old 3-D survey that we had reprocessed. The impact of hurricanes Katrina and Rita combined to destroy or damage substantial portions of our production facilities across the state, and severely damaged two of the drilling rigs being utilized in the area. Overall, the storms had a very large impact on the timing (four months) of our drilling activities and an even greater impact on our production volumes for the year. As reported, none of our personnel suffered physical injuries, and our insurance coverage will handle the substantial portion of costs to replace and repair the damage. However, the delays, coupled with the underlying decline, decreased the 2005 average production to 70.6 Mcfe per day, from 96.9 Mmcfe per day.

From a financial perspective, in 2005 we noted the following:

- Average daily production: 70.6 Mmcfe per day
- Total revenues: $195.7 million
- Net cash provided by operating activities: $134.1 million
- Diluted earnings per share: $0.31 per share
- Debt to total capitalization: 17%
- Drilling capital deployed: $86.2 million
- Reserves added from exploration: 17.5 Bcfe
- Reserve reductions from adjustments: 19.9 Bcfe (Thibodaux 3 and CL&F A-2)

Since December 2002, when we acquired our first land and seismic positions in the Biloxi Marshlands project, the Company has expended a total of approximately $190 million for all land, seismic, drilling and completions, production facilities and pipelines, over both evaluated and unevaluated areas. Through December 31, 2005, we have received net field cash flow since first production in March 2003, or less than three years, of $221 million, and the project continues to generate significant monthly cash flow, depending on prevailing commodity prices. In addition, the field continues to provide additional investment opportunities and we expect to keep one drilling rig working in the field during 2006, drilling 10 to 12 additional wells. Early up-front seismic and land, drilling and pipeline costs for the entire field has skewed the finding and development cost on an Mcfe basis, but we believe this will continue to be reduced as we resume our drilling activities, add new reserves and production therefrom.

For 2006, the Company has set its capital budget at approximately $132 million for new prospect opportunities, ranging in depths from shallow to deep, exposing the Company to unrisked reserve additions of approximately 80 Bcfe.

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, 2005 was $7.57 per Mcfe compared to $5.71 per Mcfe during the year ended December 31, 2004. 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.

RESULTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2005, COMPARED TO YEAR ENDED DECEMBER 31, 2004

Oil and natural gas revenues, which include oil and natural gas hedging activities (see note 11 of notes to consolidated financial statements), during the twelve months ended December 31, 2005, decreased $7.2 million (4%) as compared to 2004 revenues due to a 27% decrease in production volumes primarily from natural production declines, mechanical issues on a few wells and from the effects of hurricanes (see "General" above), partially offset by a 33% increase in average commodity prices on a natural gas equivalent basis and the expiration of unfavorable hedge contracts. Our average daily production decreased from 96.9 Mmcfe during 2004 to 70.6 Mmcfe for 2005. Oil and natural gas production volume totaled 25,781 Mmcfe for 2005, compared to 35,457 Mmcfe for 2004. During 2005, the Company's drilling activity was primarily focused in the Biloxi Marshlands ("BML") project area and the Terrebonne Parish area of South Louisiana. During 2005, the Company drilled or participated in the drilling of 24 wells of which 11 wells were completed, representing a 46% success rate. The following table summarizes Meridian's operating revenues, production volumes and average sales prices for the years ended December 31, 2005 and 2004.

	Year Ended December 31, 2005	Year Ended December 31, 2004	Increase (Decrease)
Production:			
Oil (MBbls)	882	1,270	(31%)
Natural gas (MMcf)	20,490	27,839	(26%)
Natural gas equivalent (MMcfe)	25,781	35,457	(27%)
Average Sales Price:			
Oil (per Bbl)	$ 39.29	$ 28.40	38%
Natural gas (per Mcf)	7.84	5.98	31%
Natural gas equivalent (per Mcfe)	7.57	5.71	33%
Operating Revenues (000's):			
Oil	$ 34,647	$ 36,060	(4%)
Natural gas	160,608	166,387	(4%)
Total	$195,255	$202,447	(4%)

Operating Expenses.

Oil and natural gas operating expenses on an aggregate basis increased $1.9 million (13%) to $15.9 million in 2005, compared to $14.0 million in 2004. On a unit basis, lease operating expenses increased $0.22 per Mcfe to $0.62 per Mcfe for the year 2005 from $0.40 per Mcfe for the year 2004. Oil and natural gas operating expenses increased primarily due to (1) operating expenses associated with new wells; (2) salt water disposal expense in the Hornet Nest area of BML;

and (3) an overall industry-wide increase in service costs.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes decreased $0.6 million (6%) to $8.8 million in 2005, compared to $9.4 million in 2004, primarily because of the decrease in natural gas production, partially offset by a higher natural gas tax rate. 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 $0.252 per Mcf (effective July 1, 2005) for natural gas. For the first six months of 2005, and the last six months of 2004, the rate was $0.208 per Mcf for natural gas, an increase from $0.171 per Mcf for the first half of 2004. On an equivalent unit of production basis, severance and ad valorem taxes increased to $0.34 per Mcfe for 2005 from

$0.26 per Mcfe for 2004.

Depletion and Depreciation.

Depletion and depreciation expense decreased $5.5 million (5%) during 2005 to $97.4 million compared to $102.9 million for 2004. This was primarily the result of the 27% decrease in production volumes in 2005 from 2004 levels, partially offset by an increase in the depletion rate as compared to the 2004 period. On a unit basis, depletion and depreciation expenses increased to $3.78 per Mcfe for 2005, compared to $2.90 per Mcfe for 2004. Depletion and depreciation expense on a per Mcfe basis increased primarily due to the impact of negative reserve revisions during the year, an overall industry-wide increase in drilling, completion and facility costs, and upward revisions of future development costs.

General and Administrative Expense.

General and administrative expenses, which are net of costs capitalized in our oil and gas properties (see note 17 of notes to consolidated financial statements), increased $2.8 million (19%) to $18.0 million in 2005 compared to $15.2 million for the year 2004, primarily due to an increase in employee compensation associated with the higher industry-wide demand for experienced personnel. Additionally, legal services were higher during 2005 as a result of various litigation matters. On an equivalent unit of production basis, general and administrative expenses increased $0.27 per Mcfe to $0.70 per Mcfe for 2005 compared to $0.43 per Mcfe for 2004.

Accretion Expense.

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 $1.1 million and $0.6 million to earnings as accretion expense during 2005 and 2004, respectively.

Hurricane Damage Repairs.

This expense of $3.1 million is related to damages incurred from hurricanes Katrina and Rita, primarily related to the Company's insurance deductible and costs in excess of insured values.

Interest Expense.

Interest expense decreased $2.5 million (34%) to $4.7 million in 2005 compared to $7.2 million for 2004. The decrease was primarily a result of the reduction in long-term borrowings. This realized interest savings was due to the 2004 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.

Taxes on Income.

The provision for income taxes for 2005 was $18.0 million as compared to $19.3 million for 2004. Income taxes were provided on book income after taking into account permanent differences between book income and taxable income.

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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 11 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 drilling results in the 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 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,		Increase
	2004	2003	(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 2004.

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, 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 Mcf (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.

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.

General and Administrative Expense.

General and administrative expenses, which are net of costs capitalized in our oil and gas properties (see note 17 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.

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. During 2004, the Company converted $20 million of convertible subordinated notes into common stock and made net repayments of $57.2 million on our long-term debt. 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.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS. Net cash flows provided by operating activities were $134.1 million for the year ended December 31, 2005, as compared to $171.5 million for the year ended December 31, 2004, a decrease of $37.4 million or 22%. This decrease was attributable to a $7.2 million decline in revenue due to lower production, partially offset by higher commodity prices and higher cash expenditures in 2005 of approximately $4.4 million, including hurricane damage repairs. Additionally, approximately $9 million of hurricane expenditures are included in year end 2005 accounts receivable, for which we have filed insurance claims. Also, changes in accounts payable when comparing 2005 to 2004, resulted in a use of cash of $13.7 million. Other changes in working capital are due to the timing of cash receipts and disbursements.

Net cash flows used in investing activities were $133 million for the year ended December 31, 2005, as compared to $142.5 million for the year ended December 31, 2004. The decrease was due to lower capital expenditures of $9.5 million. Drilling activity during the latter part of 2005 was delayed due to hurricane damage resulting in lower capital expenditures of $9.5 million when comparing 2005 to 2004.

Net cash flows used in financing activities were $2.1 million for the year ended December 31, 2005, as compared to net cash flows used in financing activities of $17.5 million for 2004. In 2005, the Company paid $2.2 million of preferred stock dividends, compared to $5.2 million in 2004. Also included in 2004 were net repayments of $57.2 million of debt, partially offset by $45.8 million raised by selling common stock. (See "Common Stock," below.)

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. A portion of the proceeds from the offering were utilized to repurchase 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. The repurchased 7,082,030 shares of common stock that were held in Treasury Stock, subsequent to the offering, 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 2004, approximately 10.7 million shares of common stock were issued for the early conversion and retirement of the Company's 9 1/2% convertible subordinated notes and a portion of the Series C redeemable preferred stock. During 2005, an additional 7.1 million shares of common stock were issued for conversion and retirement of the remaining Series C redeemable preferred stock.

CURRENT CREDIT FACILITY. On December 23, 2004, the Company amended its 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, Allied Irish Banks PLC, RZB Finance LLC and Standards Bank PLC completed the syndication group. The initial borrowing base under the Credit Facility was $130 million and it was reaffirmed by the syndication group effective November 1, 2005. As of December 31, 2005, outstanding borrowings under the Credit Facility totaled $75 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. The determination of our borrowing base is subject to a number of factors including, quantities of proved oil and gas reserves, the bank's price assumptions and other various factors unique to each member bank. Our lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that our

oil and gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect.

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.

The Company recently notified the syndication group that a shortfall would exist in the mortgage and the title opinion requirements with respect to the reserve information the Company was required to deliver to the syndication group on March 15, 2006. The primary reason for the shortfall was the inclusion of new properties drilled during 2005 included in the Company's reserve estimates, which were not previously encumbered by mortgages. Accordingly, the syndication group approved a 30-day waiver of the mortgage requirement and a 60-day waiver of the title opinion requirement. The Company expects to be in full compliance within the time periods allowed in the waiver.

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, 2005, the three-month LIBOR interest rate was 4.54%. The Credit Facility also provides for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the Credit Facility.

FORMER CREDIT FACILITY. In 2002-2004, the Company had a $175 million senior secured credit agreement. In the first nine months of 2004, the Company made repayments of $48.3 million, bringing the outstanding balance to $74 million as of September 30, 2004. On December 23, 2004, the Company made a final debt repayment of $74 million, which paid off this senior secured credit agreement in full.

SUBORDINATED CREDIT AGREEMENT. The Company had a short-term subordinated credit agreement with Fortis Capital Corp. for $25 million that had a maturity date of December 31, 2004. Note payments totaling $6.25 million were paid in 2002, $8.75 million was paid in 2003, and the remaining $10 million was paid in 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 ("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 totaling $66.9 million of 8.5% redeemable convertible preferred stock was completed during May 2002. The preferred stock was convertible into shares of the Company's common stock at a conversion price of $4.45 per share. Dividends were payable semi-annually in cash or additional preferred stock. At the option of the Company, one-third of the preferred shares could be forced to convert to common stock if the closing price of the Company's common stock exceeded 150% of the conversion price for 30 out of 40 consecutive trading days on the New York Stock Exchange. The preferred stock was 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 were 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 2004, a total of $28.9 million of preferred stock was converted into 6.5 million shares of common stock. During the first six months of 2005, the Company completed the conversion of all of the remaining outstanding shares of preferred stock to common stock with $31.6 million of stated value being converted into approximately 7.1 million shares of the Company's common stock.

CAPITAL EXPENDITURES. Capital expenditures in 2005 consisted of $132.9 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.

The 2006 capital expenditures plan is currently forecast at approximately $132 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 2006 plan utilizing cash flow from operations. When appropriate, excess cash flow from operations beyond that needed for the 2006 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, 2005 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	$1,103	$75,000	$--	$76,103

Interest	4,718	9,330		14,048
Non-cancelable operating leases	1,757	125	--	1,882
Total contractual cash obligations	$7,578	$84,455	$--	$92,033

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.

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For the year 2005, $0.8 million of dividends were accumulated (net of $0.1 million of deferred preferred stock offering costs amortized during 2005) of which all was paid in 2005. During the first six months of 2005, the Company completed the conversion of all of the remaining outstanding shares of the 8.5% redeemable convertible preferred stock to common stock, with $31.6 million of stated value being converted into approximately 7.1 million shares of the Company's common stock.

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.

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 2005, 2004, and 2003, such capitalized costs totaled $13.8 million, $11.9 million, and $10.0 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.

Changes in the quantities of our reserves could significantly impact the Company's provision for depletion and amortization of oil and natural gas properties. A 10% decrease in reserves would have increased our provision for the year by approximately 12%; however, a 10% increase in our reserves would have decreased our provision for the year by approximately 10%.

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.

At December 31, 2005, we had $26.6 million allocated to unevaluated oil and natural gas properties. A 10% increase or decrease in the unevaluated oil and natural gas properties balance would have increased or decreased our provision for depletion and amortization of oil and natural gas properties by approximately 1% for the year ended December 31, 2005.

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 judgment. 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.

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.

At December 31, 2005, we had a cushion (i.e. the excess of the ceiling over our capitalized costs) of $236.6 million (before tax). A 10% increase in prices would have increased our cushion by approximately 35%. A 10% decrease in prices would have decreased our cushion by approximately 25%. Our hedging program would reduce some of the impact of a price decline.

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 derivative contracts. These contracts 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 contracts 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 a gain of $126,000 during the year ended December 31, 2004, and a loss of $251,000 during the year ended December 31, 2005.

During the year ended December 31, 2005, the change in estimated fair value of the Company's oil and natural gas contracts was an unrealized loss of $3.6 million ($2.3 million net of tax) which is recognized in other comprehensive income. Based upon December 31, 2005, oil and natural gas commodity prices, approximately $3.4 million of the loss deferred in other comprehensive income could potentially lower gross revenues in 2006. The contract agreements expire at various dates through July 31, 2007.

Net settlements under these contract agreements reduced oil and natural gas revenues by $20,578,000 and $18,624,000 and $14,916,000 for the years ended December 31, 2005, 2004, and 2003, 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, and bank borrowings. 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, 2005 and 2004, and were determined based upon variable interest rates currently available to us for borrowings with similar terms.

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 was effective 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. The Company adopted the provisions of SFAS No. 123R on January 1, 2006, using the modified prospective method. Under this method, compensation cost will be recognized in our financial statements beginning January 1, 2006, based on the requirements of SFAS No. 123R, for all share-based payments granted or modified after that date, and based on the requirements of SFAS No. 123R for all unvested awards granted prior to the adoption date of SFAS No. 123R. The impact on the Company's results of operations is expected to be similar to the pro forma disclosures included in the notes to the financial statements.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections" which replaces Accounting Principles Board Opinions No. 20, "Accounting Changes" and Statement of Financial Accounting Standards No. 3, "Reporting Accounting Changes in Interim Financial Statements - An Amendment of APB Opinion No. 28." SFAS No. 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS No. 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The Company adopted the provisions of SFAS No. 154 on January 1, 2006.

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

The Company is 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 on 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 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

From time to time, Meridian addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. From time to time, we may enter into 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.

All of the Company's current hedging contracts are in the form of costless collars. The costless collars provide the Company with a lower limit "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 are settled monthly based on the NYMEX futures contract.

The notional amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 16% of our proved developed natural gas production and 28% 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, 2005, is provided below (see the Company's website at www.tmrc.com for a quarterly breakdown of the Company's hedge position for 2006 and beyond):

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	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Fair Value Dec 31, 2005 (in thousands)
NATURAL GAS (MMBTU)					
Jan 2006 - Mar 2006	Collar	1,690,000	$ 7.50	$11.25	$(1,282)
Apr 2006 - Oct 2006	Collar	1,130,000	$ 8.00	$14.50	37
Total Natural Gas					(1,245)
CRUDE OIL (BBLS)					
Jan 2006 - Jul 2006	Collar	113,000	$37.50	$47.50	(1,712)
Jan 2006 - Jul 2006	Collar	25,000	$40.00	$50.00	(331)
Aug 2006 - Jul 2007	Collar	168,000	$50.00	$74.00	(391)
Total Crude Oil					(2,434)
					$(3,679)

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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.

CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and therefore have been omitted.

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, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income for each of the three years in the period ended December 31, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of The Meridian Resource Corporation and subsidiaries' internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 10, 2006, expressed an unqualified opinion thereon.

BDO SEIDMAN, LLP

Houston, Texas
March 10, 2006

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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
REVENUES:			
Oil and natural gas	$195,255	$202,447	$137,124
Price risk management activities	(251)	126	--
Interest and other	692	545	355
	195,696	203,118	137,479
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	15,860	14,035	11,260
Severance and ad valorem taxes	8,811	9,394	7,608
Depletion and depreciation	97,354	102,915	75,441
General and administrative	18,010	15,169	11,610
Accretion expense	1,120	601	667
Hurricane damage repairs	3,066	--	--
Write-down of securities held	--	195	--
	144,221	142,309	106,586
EARNINGS BEFORE OTHER EXPENSES & INCOME TAXES	51,475	60,809	30,893
OTHER EXPENSES:			
Interest expense	4,724	7,154	11,496
Debt conversion expense	--	1,188	--
	4,724	8,342	11,496
EARNINGS BEFORE INCOME TAXES	46,751	52,467	19,397
INCOME TAXES:			
Current	(568)	834	(731)
Deferred	18,568	18,508	4,980
	18,000	19,342	4,249
EARNINGS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	28,751	33,125	15,148
Cumulative effect of change in accounting principle	--	--	(1,309)
NET EARNINGS	28,751	33,125	13,839
Dividends on preferred stock	902	3,877	6,593

NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	$ 27,849	$ 29,248	$ 7,246
NET EARNINGS PER SHARE BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE:			
Basic	$ 0.33	$ 0.41	$ 0.16
Diluted	$ 0.31	$ 0.37	$ 0.15
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE PER SHARE:			
Basic and Diluted	$ --	$ --	$ (0.02)
NET EARNINGS PER SHARE:			
Basic	$ 0.33	$ 0.41	$ 0.14
Diluted	$ 0.31	$ 0.37	$ 0.13
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic	84,527	72,084	53,325
Diluted	90,090	79,033	57,144

See notes to consolidated financial statements.

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

	DECEMBER 31,	
	2005	2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 23,265	$ 24,297
Restricted cash	1,234	891
Accounts receivable, less allowance for doubtful accounts of $242 [2005 and 2004]	41,188	27,763
Prepaid expenses and other	1,294	2,263
Assets from price risk management activities	528	5,705
Deferred tax asset	1,150	882
Total current assets	68,659	61,801
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $26,623 [2005] and $34,731 [2004] not subject to depletion)	1,512,036	1,377,649
Land	48	478
Equipment and other	6,540	10,039
	1,518,624	1,388,166
Less accumulated depletion and depreciation	1,032,595	938,965
Total property and equipment, net	486,029	449,201
OTHER ASSETS:		

Assets from price risk management activities	235	--
Other	879	2,272
Total other assets	1,114	2,272
TOTAL ASSETS	$ 555,802	$ 513,274

See notes to consolidated financial statements.

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

	DECEMBER 31,	
	2005	2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 7,595	$ 14,983
Revenues and royalties payable	9,149	8,117
Due to affiliates	4,638	3,866
Notes payable	1,103	870
Accrued liabilities	22,272	21,406
Liabilities from price risk management activities	3,977	8,003
Asset retirement obligations	2,879	1,331
Current income taxes payable	108	105
Total current liabilities	51,721	58,681
LONG-TERM DEBT	75,000	75,129
OTHER:		
Deferred income taxes	41,967	23,521
Liabilities from price risk management activities	464	--
Asset retirement obligations	9,085	8,293
Other	--	20
	51,516	31,834
COMMITMENTS AND CONTINGENCIES (NOTES 5, 6 AND 10)		
REDEEMABLE CONVERTIBLE PREFERRED STOCK:		
Preferred stock, 8.5%, $1.00 par value (1,500,000 shares authorized, none [2005] and 315,886 [2004] shares of Series C redeemable preferred issued at stated value)	--	31,589
STOCKHOLDERS' EQUITY:		

Common stock, $0.01 par value (200,000,000 shares authorized, 86,817,658 [2005] and 79,215,394 [2004] issued)	900	821
Additional paid-in capital	524,692	490,351
Accumulated deficit	(145,395)	(173,244)
Accumulated other comprehensive loss	(2,314)	(1,574)
Unamortized deferred compensation	(318)	(313)
Total stockholders' equity	377,565	316,041
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 555,802	$ 513,274

See notes to consolidated financial statements.

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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings	$ 28,751	$ 33,125	$ 13,839
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	--	--	1,309
Depletion and depreciation	97,354	102,915	75,441
Amortization of other assets	446	1,506	1,715
Non-cash compensation	1,845	1,920	1,579
Non-cash price risk management activities	251	(126)	--
Debt conversion expense	--	1,188	--
Write-down of securities held	--	195	--
Accretion expense	1,120	601	667
Deferred income taxes	18,568	18,508	4,980
Changes in assets and liabilities:			
Restricted cash	(343)	(891)	--
Accounts receivable	(13,425)	(3,060)	(536)
Due from affiliates	--	--	1,557
Prepaid expenses and other	969	(677)	635
Accounts payable	(7,388)	6,291	(8,150)
Due to affiliates	772	3,563	303
Revenues and royalties payable	1,032	(4,318)	57
Other assets and liabilities	4,127	10,751	(1,774)
Net cash provided by operating activities	134,079	171,491	91,622
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(132,912)	(142,436)	(71,920)
Proceeds from (settlements on) sale of property	(51)	(72)	4,893

Net cash used in investing activities	(132,963)	(142,508)	(67,027)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	10,000	75,129	--
Reductions in long-term debt	(10,129)	(132,320)	(51,430)
Proceeds - Notes payable	3,142	2,537	1,888
Reductions - Notes payable	(2,909)	(1,861)	(2,525)
Repurchase of common stock	--	(49,291)	--
Issuance of stock/exercise of stock options	13	94,777	33,185
Preferred dividends	(2,166)	(5,248)	--
Additions to deferred loan costs	(99)	(1,230)	(179)
Net cash used in financing activities	(2,148)	(17,507)	(19,061)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,032)	11,476	5,534
Cash and cash equivalents at beginning of year	24,297	12,821	7,287
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 23,265	$ 24,297	$ 12,821
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Non-cash financing activities:			
Conversion of preferred stock	$ (30,625)	$ (27,734)	$ --
Issuance of shares for settlement of accrued liabilities	$ (1,932)	$ --	$ --
Conversion of convertible 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, 2003, 2004 AND 2005 (in thousands)

	Common Stock		Additional		Accumulated	Unam
	Shares	Par Value	Paid-In Capital	Accumulated Deficit	Other Comprehensive Loss	Def Compe
Balance, December 31, 2002	50,089	$ 557	$ 378,215	$ (209,738)	$ (4,938)	$
Issuance of rights to common stock	--	8	1,256	--	--	(1
Company's 401(k) plan contribution	109	--	(498)	--	--	
Exercise of stock options	80	1	78	--	--	
Compensation expense	--	--	--	--	--	1
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	--	--	(1
Company's 401(k) plan contribution	52	--	343	--	--	
Exercise of stock options	27	--	131	--	--	
Compensation expense	--	--	--	--	--	1
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)	
Issuance of rights to common stock	--	3	1,597	--	--	(1
Company's 401(k) plan contribution	53	--	250	--	--	
Exercise of stock options	49	--	163	--	--	
Compensation expense	--	--	--	--	--	1
Accum. other comprehensive income	--	--	--	--	(740)	
Issuance for conversion of pref stock	7,099	71	30,554	--	--	
Issuance cost - 2004 stock offering	--	--	(150)	--	--	
Issuance of shares as compensation	402	5	1,927	--	--	
Preferred dividends	--	--	--	(902)	--	
Net earnings	--	--	--	28,751	--	
Balance, December 31, 2005	86,818	$ 900	$524,692	$(145,395)	$(2,314)	$

See notes to consolidated financial statements.

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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
Net earnings applicable to common stockholders	$ 27,849	$29,248	$ 7,246

Other comprehensive income (loss), net of tax, for unrealized losses from hedging activities:			
Unrealized holding losses arising during period (1)	(14,116)	(6,161)	(12,461)
Reclassification adjustments on settlement of contracts (2)	13,376	12,106	9,695
Write-down of securities held	--	185	--
	(740)	6,130	(2,766)
Total comprehensive income	$ 27,109	$35,378	$ 4,480
(1) Net of income tax (expense) benefit	$ 7,601	$ 3,317	$ 6,710
(2) Net of income tax expense	$ (7,202)	$(6,518)	$ (5,221)

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, 2005, was $1,234,000, and at December 31, 2004, was $891,000. The restricted cash is related to a contractual obligation with respect 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, 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 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 $3.9 million, $6.3 million and $9.6 million in 2005, 2004 and 2003, respectively. Cash payments for income taxes (federal and state, net of receipts) were $1,285,000 for 2005, $950,000 for 2004, and $23,000 for 2003.

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, 2005, and December 31, 2004, the Company had approximately $24,370,000 and $22,970,000, 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 applied 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, 2005, 2004 or 2003.

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

	2005	2004	2003
Net earnings applicable to common stockholders as reported	$27,849	$29,248	$7,246
Stock-based compensation (expense) benefit determined under fair value method for all awards, net of tax	(237)	(119)	63
Net earnings applicable to common stockholders pro forma	$27,612	$29,129	$7,309
Basic earnings per share:			
As reported	$ 0.33	$ 0.41	$ 0.14
Pro forma	$ 0.33	$ 0.40	$ 0.14
Diluted earnings per share:			
As reported	$ 0.31	$ 0.37	$ 0.13
Pro forma	$ 0.31	$ 0.37	$ 0.13

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 3.97%, 3.37% and 2.87%; dividend yield of 0%; volatility factors of the expected market price of the Company's common stock of 0.92, 0.96

and 1.02 for 2005, 2004 and 2003, respectively; and a weighted-average expected life of five years. These assumptions resulted in a weighted average grant date fair value of $3.43, $5.92 and $3.44 for options granted in 2005, 2004 and 2003, respectively. For purposes of the pro forma disclosures, the estimated fair value is amortized to expense over the awards' vesting period.

FAIR VALUE OF FINANCIAL INSTRUMENTS.

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings. 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, 2005 and 2004, and were determined based upon variable interest rates currently available to us for borrowings with similar terms.

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.

The Company enters into 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 year ended December 31, 2003, a gain of $126,000 during the year ended December 31, 2004, and a loss of $251,000 during the year ended December 31, 2005.

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 immediately recognized 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.

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 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. The Company adopted the provisions of SFAS No.123R on January 1, 2006, using the modified prospective method. Under this method, compensation cost will be recognized in our financial statements beginning January 1, 2006, based on the requirements of SFAS

No. 123R for all share-based payments granted or modified after that date, and based on the requirements of SFAS No. 123R for all unvested awards granted prior to the adoption date of SFAS No.123R. The impact on the Company's results of operations is expected to be similar to the pro forma disclosures made above.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections" which replaces Accounting Principles Board Opinions No. 20, "Accounting Changes" and Statement of Financial Accounting Standards No. 3, "Reporting Accounting Changes in Interim Financial Statements - An Amendment of APB Opinion No. 28." SFAS No. 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS No. 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The Company adopted the provisions of SFAS No. 154 on January 1, 2006.

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 $1.1 million, $0.6 million and $0.7 million in 2005, 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):

	2005	2004	2003
Net earnings applicable to common stockholders	$27,849	$29,248	$7,246
Cumulative effect of accounting change	--	--	1,309
Pro forma net earnings applicable to common stockholders	$27,849	$29,248	$8,555
Pro forma earnings per share:			
Basic	$ 0.33	$ 0.41	$ 0.16
Diluted	$ 0.31	$ 0.37	$ 0.15

The following table describes the change in the Company's asset retirement obligations for the years ended December 31, 2005 and 2004 (thousands of dollars):

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
Additional retirement obligations recorded in 2005	883
Settlements during 2005	(182)
Revisions to estimates and other changes during 2005	519
Accretion expense for 2005	1,120
Asset retirement obligation at December 31, 2005	$11,964

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. DEBT

CURRENT REVOLVING CREDIT AGREEMENT

On December 23, 2004, the Company amended its credit agreement 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, Allied Irish Banks PLC, RZB Finance LLC and Standard Bank PLC completed the syndication group. The initial borrowing base under the Credit Facility was $130 million and it has been reaffirmed by the syndication group effective November 1, 2005. As of December 31, 2005, outstanding borrowings under the Credit Facility totaled $75 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. The determination of our borrowing base is subject to a number of factors including, quantities of proved oil and gas reserves, the bank's price assumptions and other various factors unique to each member bank. Our lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that our oil and gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect.

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.

The Company recently notified the syndication group that a shortfall would exist in the mortgage and the title opinion requirements with respect to the reserve information the Company was required to deliver to the syndication group on March 15, 2006. The primary reason for the shortfall was the inclusion of new properties drilled during 2005 included in the Company's reserve estimates, which were not previously encumbered by mortgages. Accordingly, the syndication group approved a 30-day waiver of the mortgage requirement and a 60-day waiver of the title opinion requirement. The Company expects to be in full compliance within the time periods allowed in the waiver.

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, 2005, the three-month LIBOR interest rate was 4.54%. The Credit Facility also provides for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the Credit Facility.

FORMER CREDIT FACILITY

In 2002-2004, the Company had a $175 million senior secured credit agreement. In the first nine months of 2004, the Company made repayments of $48.3 million, bringing the outstanding balance to $74 million as of September 30, 2004. On December 23, 2004, the Company made a final debt repayment of $74 million, which paid off this senior secured credit agreement in full.

SUBORDINATED CREDIT AGREEMENT

The Company had a short-term subordinated credit agreement with Fortis Capital Corp. for $25 million that had a maturity date of December 31, 2004. Note payments totaling $6.25 million were paid in 2002, $8.75 million was paid in 2003, and the remaining $10 million was paid in 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 ("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, 2005, are as follows: none in 2006 or 2007, $75 million in 2008, and none thereafter.

5. LEASE OBLIGATIONS

The Company has a seven-year operating lease for office space with a primary term expiring in September 2006. The Company is currently in negotiations for office lease terms beyond September 2006. The Company also has operating leases for equipment with various terms, none exceeding three years. Rental expense amounted to approximately $2.5 million, $2.4 million and $2.3 million in 2005, 2004 and 2003, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $1.8 million for 2006, $0.1 million for 2007 and none thereafter.

6. COMMITMENTS AND CONTINGENCIES

LITIGATION

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 in Louisiana, as a result of

Meridian's satisfying a prior adverse judgment in favor of Amoco Production Company. Meridian has filed an answer denying Hawkins' 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 that it had been paid by Hawkins. The Company has not provided any amount for this matter in its financial statements at December 31, 2005.

TITLE/LEASE DISPUTES. Title and lease disputes may arise due to various events that have occurred in the various states in which the Company operates. These disputes are usually small and could lead to the Company over- or under-stating our reserves when a final resolution to the title dispute is made.

ENVIRONMENTAL LITIGATION. Various landowners have sued Meridian (along with numerous other oil companies) in various similar lawsuits concerning several fields in which the Company has had operations. 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. The Company, in certain instances, has indemnified third parties from the claims made in these lawsuits. The Company has not provided any amount for these matters in its financial statements at December 31, 2005.

LITIGATION INVOLVING INSURABLE ISSUES. There are no other material legal proceedings which exceed our insurance limits to which Meridian 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.

7. TAXES ON INCOME

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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
Current:			
Federal	$ (676)	$ 905	$ (568)
State	108	(71)	(163)
Deferred:			
Federal	17,480	18,160	4,980
State	1,088	348	--
Income tax expense	$18,000	$19,342	$4,249

The Company's income tax provision is attributed to the following items (thousands of dollars):

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
Earnings before cumulative effect of change in accounting principle	$18,000	$19,342	$ 4,249
Losses on derivatives recognized in other comprehensive income (loss)	(390)	3,199	(1,489)
Total income tax provision	$17,610	$22,541	$ 2,760

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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
Income tax provision computed at statutory rate	$16,363	$18,364	$ 6,331
Nondeductible costs	479	607	758
State income tax, net of federal tax benefit	1,158	302	(106)
Decrease in net operating loss carryover due to expiration	--	69	--
Change in valuation allowance	--	--	(2,734)
Income tax expense	$18,000	$19,342	$ 4,249

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,	
	2005	2004
Deferred tax assets:		
Net operating tax loss carryforward	$ 51,071	$ 41,244
Statutory depletion carryforward	950	950
Tax credits	1,311	1,987
Unrealized hedge loss	1,240	850
Other	5,214	4,698
Total deferred tax assets	59,786	49,729

Deferred tax liabilities:		
Book in excess of tax basis in oil and gas properties	100,603	72,298
Basis differential in long-term investments	0	70
Total deferred tax liabilities	100,603	72,368
Net deferred tax asset (liability)	$(40,817)	$(22,639)

As of December 31, 2005, the Company has approximately $145.9 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, 2005, 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	39,701	26,184
2019	47,730	48,630
2020	31	31
2021	36	36
2022	13,053	13,786
2023	44,668	44,516
TOTAL	$145,918	$133,882

As of December 31, 2005, the Company had approximately $1.3 million 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 2005.

8. REDEEMABLE CONVERTIBLE PREFERRED STOCK

A private placement totaling $66.9 million of 8.5% redeemable convertible preferred stock was completed during May 2002. The preferred stock was convertible into shares of the Company's common stock at a conversion price of $4.45 per share. Dividends were payable semi-annually in cash or additional preferred stock. At the option of the Company, one-third of the preferred shares could be forced to convert to common stock if the closing price of the Company's common stock exceeded 150% of the conversion price for 30 out of 40 consecutive trading days on the New York Stock Exchange. The preferred stock was 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 were 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 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. During the first six months of 2005, the Company completed the conversion of all of the remaining outstanding shares of the 8.5% redeemable convertible preferred stock to common stock, with $31.6 million of stated value being converted into approximately 7.1 million shares of the Company's common stock.

During 2005, $0.8 million of dividends were accumulated (net of $0.1 million of deferred preferred stock offering costs amortized during 2005) and paid as the Company completed the conversion of the remaining shares of preferred stock to common stock. 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.

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9. 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. A portion of the proceeds from the offering were utilized to repurchase 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. The repurchased 7,082,030 shares of common stock that were held in Treasury Stock, subsequent to the offering, 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 was used for exploration activities and for other general corporate purposes.

WARRANTS

The Company had the following warrants outstanding at December 31, 2005:

WARRANTS	NUMBER OF SHARES	EXERCISE PRICE	EXPIRATION DATE
Executive Officers	1,428,000	$5.85	*
General Partner	1,758,404	$0.11	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, 2005, 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 1,758,404 shares of common stock at an exercise price of $0.11 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. There are adequate authorized unissued common stock shares that are required to be issued upon conversion of the General Partner Warrants. The Company is not required to redeem the General Partner Warrants.

On June 7, 1994, the shareholders of the Company approved a conversion of Class "B" Warrants into Executive Officer 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. The Executive Officer Warrants expire one year following the date on which the respective officer ceases to be an employee of the Company. The Executive Officer 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 Executive Officer Warrants held by the officer for an amount per Executive Officer 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, 2005, 2004 and 2003, 2,162,478, 1,670,685, and 2,130,334 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, 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
Granted	45,000	4.68
Exercised	(48,500)	3.37
Canceled	(94,500)	9.93
Outstanding at December 31, 2005	3,595,050	$4.12
Shares exercisable:		
December 31, 2003	3,510,700	$4.06
December 31, 2004	3,498,050	$4.06
December 31, 2005	3,430,050	$3.97

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
RANGE OF EXERCISABLE PRICES	OUTSTANDING AT DECEMBER 31, 2005	WEIGHTED AVERAGE EXERCISE PRICE	EXERCISABLE AT DECEMBER 31, 2005	WEIGHTED AVERAGE EXERCISE PRICE
$3.00 - $4.99	3,107,650	$ 3.39	3,081,400	$ 3.38
$5.32 - $9.00	365,750	8.00	227,000	8.16
$11.13	121,650	11.13	121,650	11.13
	3,595,050	$ 4.12	3,430,050	$ 3.97

The weighted average remaining contractual life of options outstanding at December 31, 2005, was approximately three 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 2005, $400,000 for 2004 and $316,000 for 2003, 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, 2005, the plan had reserved 3,850,000 shares of common stock for future issuance and 3,225,988 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 $1,595,000, $1,577,000 and $1,330,000 for 2005, 2004 and 2003 periods, respectively, and is reflected in general and administrative expense and in oil and gas properties for the years ended December 31, 2005, 2004 and 2003, 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.

10. 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 $300,000, $299,000 and $331,000 in 2005, 2004, and 2003, 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 $6.4 million, $6.9 million and $4.3 million in 2005, 2004 and 2003, 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.

11. 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. From time to time, we enter into 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 derivative contracts. These contracts 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 contracts 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 year ended December 31, 2003, a gain of $126,000 during the year ended December 31, 2004, and a loss of $251,000 during the year ended December 31, 2005.

For the year ended December 31, 2005, the change in estimated fair value of the Company's oil and natural gas contracts was an unrealized loss of $3.6 million ($2.3 million net of tax) which is recognized in other comprehensive income. Based upon oil and natural gas commodity prices at December 31, 2005, approximately $3.4 million of the loss deferred in other comprehensive income could potentially lower gross revenues in 2006. These derivative agreements expire at various dates through July 31, 2007.

Net settlements under these contracts reduced oil and natural gas revenues by $20,578,000, $18,624,000 and $14,916,000 for the years ended December 31, 2005, 2004, and 2003 respectively, as a result of hedging transactions.

All of the Company's current hedging contracts are in the form of costless collars. The costless collars provide the Company with a lower limit "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 are settled monthly based on the NYMEX futures contract.

The notional amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 16% of proved developed natural gas production and 28% of 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 hedging agreements is recorded on the consolidated balance sheet as assets or liabilities. The estimated fair value of hedging agreements as of December 31, 2005, is provided below:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Fair Value Dec 31, 2005 (in thousands)
NATURAL GAS (MMBTU)					
Jan 2006 - Mar 2006	Collar	1,690,000	$ 7.50	$11.25	$(1,282)
Apr 2006 - Oct 2006	Collar	1,130,000	$ 8.00	$14.50	37
Total Natural Gas					(1,245)
CRUDE OIL (BBLS)					
Jan 2006 - Jul 2006	Collar	113,000	$37.50	$47.50	(1,712)
Jan 2006 - Jul 2006	Collar	25,000	$40.00	$50.00	(331)
Aug 2006 - Jul 2007	Collar	168,000	$50.00	$74.00	(391)
Total Crude Oil					(2,434)
					$(3,679)

12. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2005, 2004 and 2003, were as follows (based on sales exceeding 10% of total oil and natural gas revenues):

	YEAR ENDED DECEMBER 31,		
CUSTOMER	2005	2004	2003
Superior Natural Gas.................	46%	45%	19%
Crosstex/Louisiana Intrastate Gas....	19%	22%	24%
Conoco, Inc..........................	--	--	10%

13. 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 $9,997,000, $8,539,000 and $5,161,000 for the years ended December 31, 2005, 2004 and 2003, respectively, in oil and natural gas drilling activities for which the Company was the operator. Net amounts due to TODD,

JAR and Mr. Reeves were approximately $2,308,000 and $1,751,000 as of December 31, 2005 and 2004, respectively. Net amounts due to Sydson and Mr. Mayell were approximately $2,330,000 and $2,115,000 as of December 31, 2005 and 2004, 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, 2005, 2004 and 2003 and received fees of approximately $320,000, $255,000 and $210,000, 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 10 above, pursuant to which he was paid approximately $464,000 during 2005, $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, 2005, 2004 and 2003, and received fees of approximately $19,000, $12,000 and $49,000, 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. Mr. Messersmith also participated in the Management Plan described in Note 10 above, pursuant to which he was paid approximately $702,000 during 2005, $688,000 during 2004 and $360,000 during 2003.

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 Land 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 $100,000, $80,000 and $40,000 for the years 2005, 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 $111,000, $101,000 and $42,000 for the years 2005, 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 previous 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 years ended December 31, 2005 and 2004, and received fees of approximately $32,000 and $67,000, respectively. Currently he is a partner in the law firm of J. Todd Reeves and Associates, and is providing legal services to the Company and received fees of approximately $100,000 in 2005. Such fees exceeded 5% of the gross revenues for these firms 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.

Michael W. Mayell, the son of Michael J. Mayell, an officer and Director of Meridian, is a staff member in the Production Department, and was paid $79,000, $60,000, and $30,000, for the years 2005, 2004 and 2003, respectively. James T. Bond, former Director of Meridian, is the father-in-law of Michael J. Mayell, and has provided consultant services to the Company and received fees in the amount of $175,000, $124,000, and $115,000, for the years 2005, 2004 and 2003, respectively.

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14. EARNINGS PER SHARE

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

	(in thousands, except per share) YEAR ENDED DECEMBER 31,		
	2005	2004	2003
Numerator:			
Net earnings applicable to common stockholders	$27,849	$29,248	$ 7,246
Plus income impact of assumed conversions:			
Preferred stock dividends	N/A	N/A	N/A
Interest on convertible subordinated notes	--	270	N/A
Net earnings applicable to common stockholders plus assumed conversions	$27,849	$29,518	$ 7,246

Denominator:			
Denominator for basic earnings per share - weighted-average shares outstanding	84,527	72,084	53,325
Effect of potentially dilutive common shares:			
Warrants	4,755	4,508	3,393
Employee and director stock options	808	1,589	426
Convertible subordinated notes	N/A	852	N/A
Redeemable preferred stock	N/A	N/A	N/A
Denominator for diluted earnings per share - weighted-average shares outstanding and assumed conversions	90,090	79,033	57,144
Basic earnings per share	$ 0.33	$ 0.41	$ 0.14
Diluted earnings per share	$ 0.31	$ 0.37	$ 0.13

N/A = Not Applicable, meaning anti-dilutive for periods presented. Due to its anti-dilutive effect on earnings per share, approximately 2.1 million shares in 2005, 9.8 million shares in 2004 and 22.7 million shares in 2003 related to our redeemable preferred stock, convertible subordinated notes, stock options and warrants were excluded from the dilutive shares.

15. ACCRUED LIABILITIES

Below is the detail of our accrued liabilities on our balance sheets as of December 31 (thousands of dollars):

	2005	2004
Capital expenditures	$12,853	$12,662
Operating expenses/Taxes	2,794	2,005
Hurricane damage repairs	2,717	--
Compensation	1,949	3,355
Interest	503	60
Dividends	--	1,346
Other	1,456	1,978
TOTAL	$22,272	$21,406

16. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Results of operations by quarter for the year ended December 31, 2005 were (thousands of dollars, except per share):

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

2005				
Revenues	$50,044	$44,103	$36,845	$64,704
Results of operations from exploration and production activities(1)	17,486	12,675	10,534	29,307
Net earnings(2)	$ 6,127	$ 4,126	$ 3,276	$14,320
Net earnings per share:(2)				
Basic	$ 0.08	$ 0.05	$ 0.04	$ 0.17
Diluted	$ 0.07	$ 0.05	$ 0.04	$ 0.16

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

	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 (2)	$ 5,287	$ 7,745	$ 7,786	$ 8,430
Net earnings per share:(2)				
Basic	$ 0.08	$ 0.11	$ 0.10	$ 0.11
Diluted	0.08	0.10	0.09	0.10

(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 hurricane damage repairs.

(2) Applicable to common stockholders

17. 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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
(thousands of dollars)			
Costs incurred during the year:(1)			
Property acquisition costs			

Unproved	$ 7,097	$ 16,687	$ 4,107
Proved	--	--	--
Exploration	110,669	93,682	42,081
Development	14,916	31,610	25,586
Asset retirement cost accruals, net	1,220	4,921	1,326
	$133,902	$146,900	$73,100

(1) Costs incurred during the years ended December 31, 2005, 2004 and 2003 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $13,814,000, $11,924,000 and $10,030,000, respectively.

CAPITALIZED COSTS RELATING TO OIL AND NATURAL GAS PRODUCING ACTIVITIES

	DECEMBER 31,	
	2005	2004
(thousands of dollars)		
Capitalized costs	$1,512,036	$1,377,649
Accumulated depletion	1,027,430	931,033
Net capitalized costs	$ 484,606	446,616

At December 31, 2005 and 2004, unevaluated costs of $26,623,000 and $34,731,000, 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

	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
(thousands of dollars)			
Operating Revenues:			
Oil	$ 34,647	$ 36,060	$ 35,032
Natural Gas	160,608	166,387	102,092
	$195,255	202,447	137,124
Less:			
Oil and natural gas operating costs	15,860	14,035	11,260
Severance and ad valorem taxes	8,811	9,394	7,608

Depletion	96,396	101,944	74,456
Accretion expense	1,120	601	667
Hurricane damage repairs	3,066	--	--
Income tax	26,950	19,342	4,249
	152,203	145,316	98,240
Results of operations from oil and natural gas producing activities	$ 43,052	$ 57,131	$ 38,884
Depletion expense per Mcfe	$ 3.74	$ 2.88	$ 2.61

ESTIMATED QUANTITIES OF PROVED RESERVES

The following table sets forth the net proved reserves of the Company as of December 31, 2005, 2004 and 2003, and the changes therein during the years then ended. The reserve information was reviewed by T. J. Smith & Company, Inc., independent reservoir engineers, for 2005, 2004 and 2003. 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, 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
Production during 2005	(882)	(20,490)
Discoveries and extensions	366	15,283
Revisions of previous quantity estimates and other	(671)	(15,875)
BALANCE AT DECEMBER 31, 2005	5,177	79,917
PROVED DEVELOPED RESERVES:		
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
Balance at December 31, 2005	3,492	62,524

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 reviewed by our 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.

	AT DECEMBER 31,		
	2005	2004	2003
(thousands of dollars)			
Future cash flows	$1,122,282	$ 897,839	$ 842,945
Future production costs	(163,804)	(139,112)	(118,775)
Future development costs	(55,212)	(39,352)	(30,044)
Future net cash flows before income taxes	903,266	719,375	694,126
Future taxes on income	(201,582)	(135,472)	(116,570)
Future net cash flows	701,684	583,903	577,556
Discount to present value at 10 percent per annum	(144,481)	(113,546)	(121,673)
Standardized measure of discounted future net cash flows	$ 557,203	$ 470,357	$ 455,883

The average expected realized price for natural gas in the above computations was $10.40, $6.40 and $6.07 per Mcf at December 31, 2005, 2004, and 2003, respectively. The average expected realized price used for crude oil in the above computations was $59.37, $42.33 and $32.05 per Bbl at December 31, 2005, 2004, and 2003, respectively. No consideration has been given to the Company's hedged transactions.

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, 2005, 2004 and 2003 (thousands of dollars):

YEAR ENDED DECEMBER 31,		
2005	2004	2003

Balance at Beginning of Period	$ 470,357	$ 455,883	$ 429,835
Sales of oil and gas, net of production costs	(170,584)	(179,018)	(118,256)
Changes in sales & transfer prices, net of production costs	293,294	32,203	82,200
Revisions of previous quantity estimates	(130,813)	22,468	(24,563)
Sales of reserves-in-place	--	--	(5,026)
Current year discoveries, extensions, and improved recovery	107,393	117,178	67,676
Changes in estimated future development costs	(16,764)	(11,331)	(7,824)
Development costs incurred during the period	10,654	9,851	20,511
Accretion of discount	47,036	45,588	42,983
Net change in income taxes	(49,453)	(23,278)	(21,186)
Change in production rates (timing) and other	(3,917)	813	(10,467)
Net change	86,846	14,474	26,048
Balance at End of Period	$ 557,203	$ 470,357	$ 455,883

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

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE 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 2005. 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 2005 that could significantly affect these controls.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining a system of adequate internal control over the Company's financial reporting, which is designed to provide reasonable assurance regarding the preparation of reliable published consolidated financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's system of internal control over financial reporting as of December 31, 2005. In making this assessment, the Company's management used the criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" that the Committee of Sponsoring Organizations of the Treadway Commission issued.

Based on its assessment using those criteria, management believes that, as of December 31, 2005, the Company's system of internal control over financial reporting was effective.

The Company's independent registered public accounting firm has audited our assessment of the Company's internal control over financial reporting, which report follows.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders and Board of Directors
The Meridian Resource Corporation

We have audited management's assessment, included in Management's Annual Report on Internal Control Over Financial Reporting, that The Meridian Resource Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2005, and our report dated March 10, 2006, expressed an unqualified opinion thereon.

BDO Seidman, LLP

Houston, Texas
March 10, 2006

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 SEC on or before May 1, 2006.

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, 2005 and 2004

   (iii) Consolidated Statements of Operations for each of the three years in the period ended December 31, 2005

   (iv) Consolidated Statements of Changes in Stockholders' Equity for each of the three years in the period ended December 31, 2005

   (v) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2005

   (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).

*4.3 Common Stock Purchase Warrant of the Company dated October 16, 1990, issued to Michael J. Mayell (incorporated by reference to Exhibit 10.9 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).

*4.4 Registration Rights Agreement dated October 16, 1990, among the Company, Joseph A.

Reeves, Jr. and Michael J. Mayell (incorporated by reference to Exhibit 10.7 of the Company's Registration Statement on Form S-4, as amended (Reg. No. 33-37488)).

*4.5 Warrant Agreement dated June 7, 1994, between the Company and Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1994).

*4.6 Warrant Agreement dated June 7, 1994, between the Company and Michael J. Mayell (incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1994).

4.7 Amended and Restated Credit Agreement, dated December 23, 2004, among the Company, Fortis Capital Corp., as Administrative Agent, Sole Lead Arranger and Bookrunner, Comerica Bank, as Syndication Agent, Union Bank of California, N.A., as Documentation Agent, and the several lenders from time to time parties thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated December 23, 2004).

4.8 The Meridian Resource Corporation Directors' Stock Option Plan (incorporated by reference to Exhibit 10.5 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).

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).

10.1 See exhibits 4.2 through 4.9 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).

*10.4 Employment Agreement dated August 18, 1993, between the Company and Michael J. Mayell (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1995).

*10.5 Form of Indemnification Agreement between the Company and its executive officers and directors (incorporated by reference to Exhibit 10.6 of the Company's Annual Report on Form 10-K for the year ended December 31, 1994).

*10.6 Deferred Compensation agreement dated July 31, 1996, between the Company and Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1996).

*10.7 Deferred Compensation agreement dated July 31, 1996, between the Company and Michael J. Mayell (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1996).

*10.8 Texas Meridian Resources Corporation 1995 Long-Term Incentive Plan (incorporated by reference to the Company's Annual Report on Form 10-K for the year-ended December 31, 1996).

*10.9 Texas Meridian Resources Corporation 1997 Long-Term Incentive Plan (incorporated by reference from the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 1997).

*10.14 Employment Agreement with Lloyd V. DeLano effective November 5, 1997 (incorporated by reference from the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 1998).

*10.15 The Meridian Resource Corporation TMR Employee Trust Well Bonus Plan (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

*10.16 The Meridian Resource Corporation Management Well Bonus Plan (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

*10.17 The Meridian Resource Corporation Geoscientist Well Bonus Plan (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

*10.18 Modification Agreement effective January 2, 1999, by and among the Company and affiliates of Joseph A. Reeves, Jr. (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

*10.19 Modification Agreement effective January 2, 1999, by and among the Company and affiliates of Michael J. Mayell (incorporated by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

10.20 Amended and Restated Credit Agreement, dated December 23, 2004, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner, Comerica Bank, as syndication agent, and Union Bank of California, N.A., as documentation agent, and the several lenders from time to time parties thereto (incorporated by reference from the Company's Current Report on Form 8-K dated December 23, 2004).

21.1 Subsidiaries of the Company (incorporated by reference to Exhibit 21.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2000).

**23.1 Consent of BDO Seidman, LLP.

**23.2 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.

**31.3 Certification of Chief Accounting Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.

**32.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

**32.2 Certification of President pursuant to Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

**32.3 Certification of Chief Accounting Officer pursuant Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

* 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, 2006

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, 2006
BY: /s/ MICHAEL J. MAYELL Michael J. Mayell	President and Director	March 15, 2006
BY: /s/ LLOYD V. DELANO Lloyd V. DeLano	Chief Accounting Officer	March 15, 2006
BY: /s/ E. L. HENRY E. L. Henry	Director	March 15, 2006
BY: /s/ JOE E. KARES Joe E. Kares	Director	March 15, 2006

BY: /s/ GARY A. MESSERSMITH Gary A. Messersmith	Director	March 15, 2006
BY: /s/ DAVID W. TAUBER David W. Tauber	Director	March 15, 2006
BY: /s/ JOHN B. SIMMONS John B. Simmons	Director	March 15, 2006
BY: /s/ FENNER R. WELLER, JR. Fenner R. Weller, Jr.	Director	March 15, 2006

Index To Exhibit

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